INDIANA

2024 DUKE ENERGY | INTEGRATED RESOURCE PLAN

DUKE ENERGY

BUILDING A SMARTER ENERGY FUTURE ®

Letter from Duke Energy Indiana's President

November 1, 2024

Chairman Huston & Director Borum:

We are pleased to present Duke Energy Indiana's 2024 Integrated Resource Plan (IRP). On behalf of dozens of Duke Energy contributors as well as our collaborators from 1898 & Company, we are proud to present this body of work which the utility will rely upon to ensure safe, reliable, and affordable service to our customers in the years ahead, while adding needed additional power capacity to our system.

We have been focused on improvements to our IRP processes, technical work and ultimate work product since receiving feedback from commission staff and stakeholders after filing our 2021 IRP. Upon receipt of the 2021 IRP Director's Report, we committed ourselves to improvement. We conducted listening sessions with our most interested external stakeholders, developed multiple workstreams focused on delivering more transparent and data-driven load forecasting, enhanced modeling and analysis of demand-side resources and energy efficiency, and a transparent, robust and collaborative stakeholder process. A discussion of new areas of focus as well as improvement since the 2021 IRP are provided in Chapters 1 and 2 of the document. We thank our stakeholders for their participation in a total of 10 public and technically oriented meetings. The input we received from the commission as well as our stakeholders led to the constructive result presented here.

Driving and informing the Company's resource planning process are the Five Pillars of Indiana energy policy, which were incorporated into state law in 2023. The plan also prioritizes serving expected new load from successful economic development. The preferred portfolio provides pathways to achieve significant incremental capacity for our system in the quickest, most economical fashion possible — retiring rapidly aging assets and replacing those with highly efficient, dispatchable generators; repurposing other generators where prudent; and adding solar and storage assets.

Recognizing time is of the essence for adding power generation capacity to our system, we plan to maximize the value of existing generator interconnection rights to add efficient resources while repurposing existing generation infrastructure. We also accounted for ongoing uncertainties in federal regulation, MISO resource accreditation and planning reserve margin requirements, and supply chain constraints. The ultimate cost to customers is always a consideration and influenced our choices. The plan maintains critical optionality to respond to changing market and regulatory conditions.

The robust 2024 IRP analysis supports a set of low or no regrets near-term actions that will advance the plan and ensure that we continue to safely, reliably, and affordably serve our customers and support Indiana's growing economy.

Sincerely,

Stan Pinegar
President

Nathan Gagnon
Managing Director, IRP & Analytics

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Executive Summary

For over a century, Duke Energy Indiana (or the "Company") has proudly provided safe and reliable service to residential customers, communities, and commercial, industrial, and governmental enterprises across Indiana. The Company serves its customers with approximately 6,900 megawatts ("MW") of generation capacity, serving 900,000 electric customers across its 23,000 mile service territory. The Company's diverse portfolio, comprised of coal, integrated gasification combined cycle ("IGCC"), natural gas, oil, solar, wind, hydroelectric, and energy storage resources, together with strategic participation in the Midcontinent Independent System Operator ("MISO") market, provides a balanced mix of energy and capacity to support Indiana's economic growth and the long-term vitality of the state. Duke Energy Indiana's recent economic development wins add approximately 300 MW of additional demand by 2030. Economic development growth alone will create nearly 6,000 jobs and invest over $13 billion in communities served by Duke Energy Indiana. Blend 2, the Preferred Portfolio for this Integrated Resource Plan ("IRP"), ensures that the Company will continue to safely, reliably, and affordably serve customers in Indiana, providing incremental capacity to support customer and economic development growth while improving the environmental sustainability of the resource mix.

A Resource Plan for a Changing Energy Landscape

For decades, coal-fired generation formed the backbone of a reliable and affordable electric system for Duke Energy Indiana and for the nation at large. Over time, the Company has built on this strong foundation to benefit Indiana customers by adding new resources to provide fuel diversity, enhance flexibility, improve environmental sustainability, and support economic growth. Duke Energy Indiana remains committed to maintaining reliability and affordability while transitioning to an increasingly diverse and environmentally sustainable mix of natural gas, wind, solar, hydroelectric, and energy storage resources.

This necessary transition is taking place against a backdrop of profound transformation in the energy landscape, both in Indiana and nationally as outlined in Chapter 1 (Planning for the Future Energy Landscape). Consequential changes in the marketplace and regulatory environment since the Company submitted its previous IRP in 2021 have led the Company to make certain course adjustments, the opportunity for which is an important and valuable feature of the iterative IRP process. Inflation and supply chain challenges have increased costs and project lead times for new resources, including resources for which the Company had previously expected to see nominal dollar cost declines. In addition, delays in the MISO interconnection queue and to permitting have further slowed the pace at which new resources can be connected to the system. These higher costs and longer lead times come at a time of growing load, with an expanding manufacturing base requiring reliable, around-the-clock energy supply. In recognition of the needs of a growing economy and to ensure continued system reliability as the market share of weather-dependent renewable resources increases, MISO continues to refine and reform its capacity accreditation methods, moving to the seasonal accredited capacity ("SAC") construct in 2022 and proposing the direct loss of load ("DLOL") method in 2024. These MISO reforms put a premium on firm, dispatchable capacity resources that can serve customer needs on demand. Coinciding with the MISO reforms, the Company is seeing reliability risk shift from summer to winter hours. These changes combine to significantly increase the importance of firm winter capacity. As just one example, solar resources received 50% capacity accreditation in the 2021 IRP based on summer performance. Solar's 2% winter capacity accreditation under MISO's proposed DLOL construct significantly changes the role of that resource in the 2024 IRP analysis. Finally, as the Company was developing the 2024 IRP, the Environmental Protection Agency ("EPA") finalized its Clean Air Act Section ("CAA") 111 Rule ("EPA CAA Section 111 Rule") dictating specific actions for existing coal-fired generation and new natural gas generation. In this environment, the Company must advance solutions while prudently managing risks and uncertainties to ensure it continues to meet the needs of its customers.

Three key external factors in particular have added complexity and greater uncertainty in planning since the 2021 IRP: (1) regulatory requirements under the contested EPA CAA Section 111 Rule, (2) the potential for significant increases in load resulting from economic development in the region, and (3) cost volatility for new resources as the Company plans to replace aging coal units. Crucially, the Preferred Portfolio for the 2024 IRP includes opportunities to adjust course in response to changing conditions in these and other areas. The Company is mindful that it must keep a sharp eye on the Five Pillars of energy policy[1] guiding utilities in Indiana – reliability, resiliency, stability, affordability and environmental sustainability – as it transitions its generation fleet for the future.

Duke Energy Indiana's 2024 IRP is designed to reliably and affordably meet current and future customers' needs over the next 20 years, adding incremental generating capacity to support customer growth and economic development, retiring and replacing aging assets, and upgrading and repurposing others where reasonable and prudent, while maintaining optionality to respond to changing market and regulatory conditions. Chapter 2 (Methodology) explains in detail the analytical framework and tools used to develop the plan, and Chapter 3 (Key Assumptions) provides information on the forecasts and other inputs to the

1 Indiana Code 8-1-2-0.6.

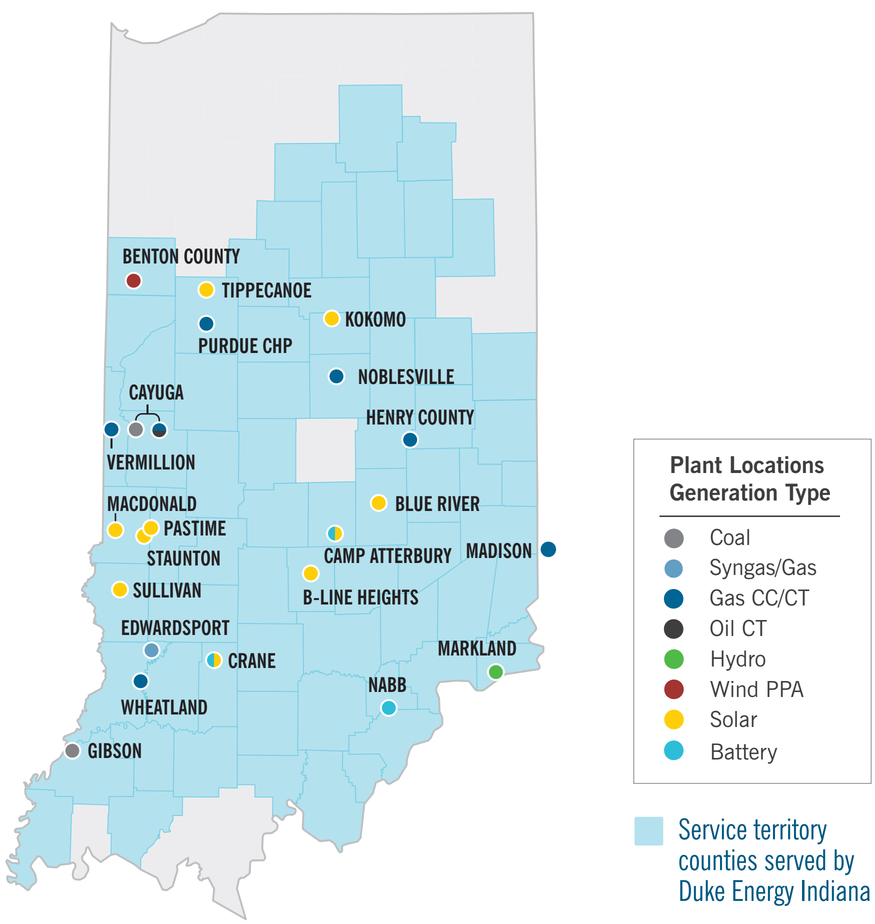
quantitative analytics. The results of those analytics are presented in Chapter 4 (Candidate Resource Portfolios), while Chapter 5 (Preferred Resource Portfolio) identifies the key factors influencing the selection of the Preferred Portfolio. Chapter 6 (Short-Term Action Plan) details the prudent, risk-balanced actions that the Company plans to take in the near term to advance the Preferred Portfolio. Finally, the Company has prepared 12 appendices that provide additional information on the inputs, assumptions, stakeholder process, and other aspects of the 2024 IRP.

Duke Energy Indiana Today

Duke Energy Indiana serves customers in 69 of the state's 92 counties with a resource portfolio that includes solar, wind, hydroelectric, coal, natural gas, and battery energy storage assets. Figure 1 provides a map of the Company's generating resources across Duke Energy Indiana's service territory.

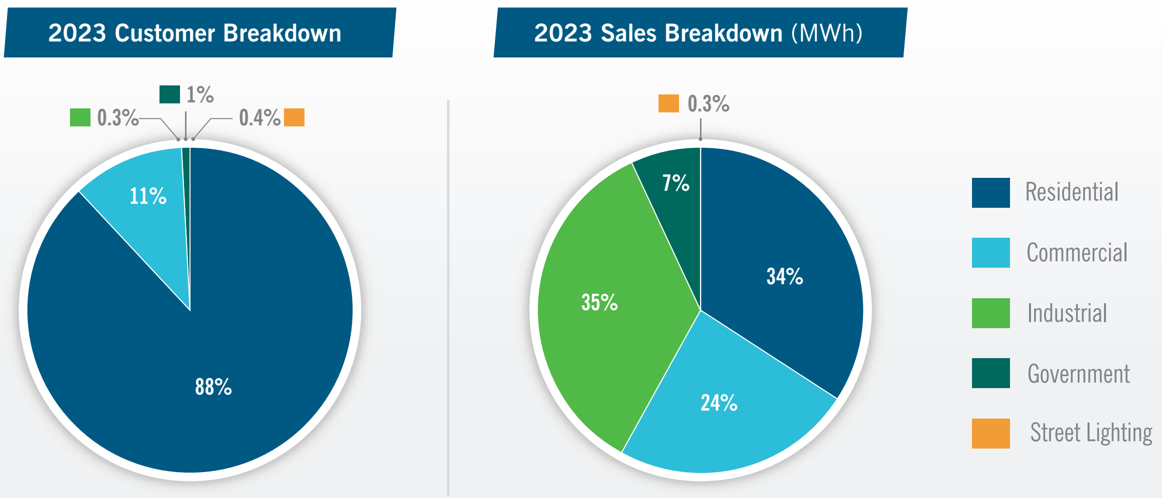
As the state's largest electric utility, the Company served peak demand approaching 6,000 MW in 2023 and generated approximately 29.5 terawatt-hours, or 29,500,000 megawatt-hours ("MWh"), of electricity. Figure 2 shows the composition of the Company's customer base by number of customers and by electricity sales.

Figure 1: Duke Energy Indiana Counties Served and Generating Resource Locations



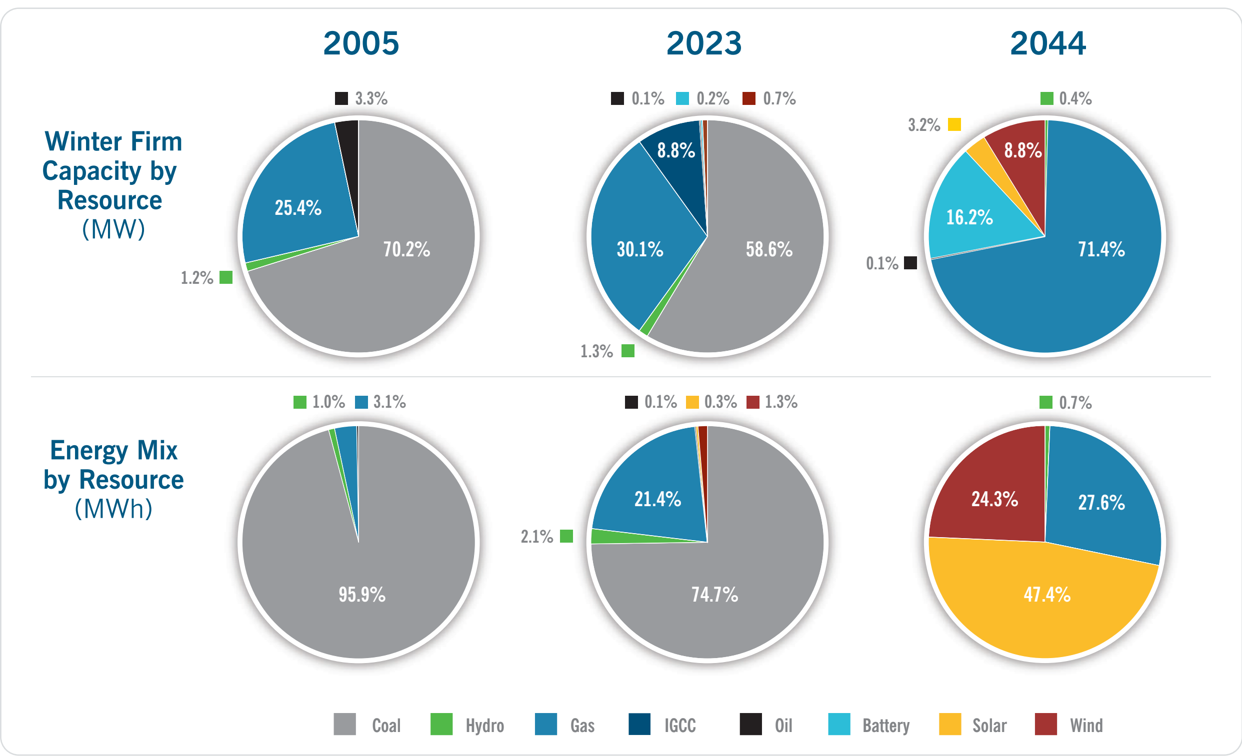
Note: Combined cycle ("CC"); combustion turbine ("CT"); power purchase agreement ("PPA")

Figure 2: Composition of Duke Energy Indiana Customer Base



Over time, the Company has steadily transitioned the portfolio of resources with which it serves these customers, replacing aging assets while improving resource diversity and environmental sustainability. The Preferred Portfolio positions the Company to continue these improvements into the future while supporting Indiana's growing economy. Figure 3 shows Duke Energy Indiana's changing energy and capacity mix over time.

Figure 3: Duke Energy Indiana Energy and Capacity Mix Over Time



Note: Energy and capacity for Duke Energy Indiana supply-side resources only. IGCC is included with coal in the energy mix. Edwardsport IGCC is converted to natural gas fuel by 2030 and included with gas for both energy and capacity in 2044.

Developing an Integrated Resource Plan

Planning Objectives

Driving and informing the Company's resource planning process are the Five Pillars, which were added to Indiana state law in 2023. As referenced above, the pillars governing utility decision-making include reliability, resiliency, stability, affordability and environmental sustainability. In addition to the Five Pillars, the Company's planning objectives include the consideration of risk and uncertainty, a vital aspect of long-term planning, particularly in the context of this changing energy landscape. Figure 4 illustrates the planning objectives, which are discussed in detail in Chapter 2.

Figure 4: Duke Energy Indiana Resource Planning Objectives

Stakeholder Process

The Company believes that stakeholder engagement is critical for resource planning, and it is essential to consider the needs and concerns of a broad audience of customers, regulators, environmental organizations, social advocates, community agencies, elected officials, and employees. Duke Energy Indiana recognizes that stakeholders have varying backgrounds in key resource planning concepts and, for meaningful stakeholder engagement for all participants, the Company invited interested individuals to participate in public meetings that discussed key resource concepts at a high level. Duke Energy Indiana also asked interested individuals to self-identify as "technical representatives" and participate in technical meetings to discuss detailed, sometimes confidential, modeling assumptions subject to a nondisclosure agreement.

Over the course of eight months, more than 146 individuals representing 75 organizations actively participated in a five-part engagement series consisting of a total of 10 public and technical meetings. In the public meetings, Duke Energy Indiana reviewed the overall purpose, components, and timeline of the 2024 IRP. Presenters and attendees then engaged in discussions around non-confidential modeling and input assumptions, scenario and scorecard

Figure 5: Public Stakeholder Meeting Participation

development, and several other resource planning concepts described further in the series summaries in Appendix A (Stakeholder Engagement). In the technical meetings, technical representatives dove deeper into the more complex and detailed IRP modeling assumptions and methodologies. Figure 5 shows the engagement throughout the stakeholder process.

Public meeting presentations and summaries were shared with stakeholders on the Duke Energy Indiana IRP website,[2] and individuals had the opportunity to provide comments and feedback to the Company during the meetings and throughout the stakeholder process via a dedicated email address. Technical representatives were given access to detailed modeling files and data as it became available. Feedback from all stakeholders was thoughtfully considered and a significant amount was incorporated into this 2024 IRP. The feedback considered and incorporated is discussed in Appendix A and throughout the IRP.

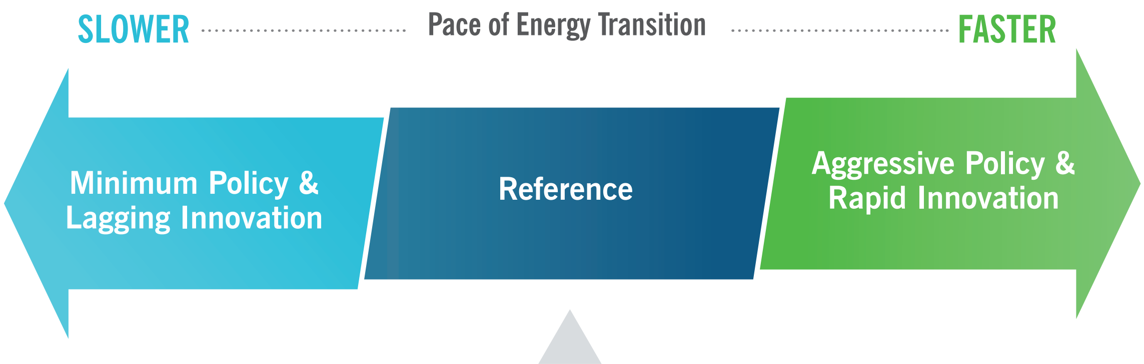
Analytical Framework

The Company developed a robust analytical framework for the 2024 IRP. This framework, described in detail in Chapter 2, was centered around six generation strategies, each of which was evaluated in three potential scenarios for the future, or "worldviews." The worldviews consisted of (1) the Reference Scenario, which includes existing regulations and the Company's base case forecasts and expectations for the most likely future, (2) Aggressive Policy & Rapid Innovation, which assumes regulatory and technological factors incentivize and enable a more rapid energy transition, and (3) Minimum Policy & Lagging Innovation ("Minimum"), which assumes a more lenient regulatory environment, including reversal of the EPA CAA Section 111 Rule, and a slower pace of energy transition. The worldviews represent three different versions of the future and were deliberately constructed to explore the range of plausible future outcomes. Each was modeled with a distinct set of assumptions corresponding to the market and regulatory factors that define the worldview, and they are not representative of or shaped by the Company's policy objectives.

The worldviews and their implications for the pace of energy transition are illustrated in Figure 6.

2 Duke Energy, Indiana Integrated Resource Plan, available at www.duke-energy.com/IndianaIRP.

Figure 6: 2024 IRP Scenarios ("Worldviews") Exploring Pace of Energy Transition



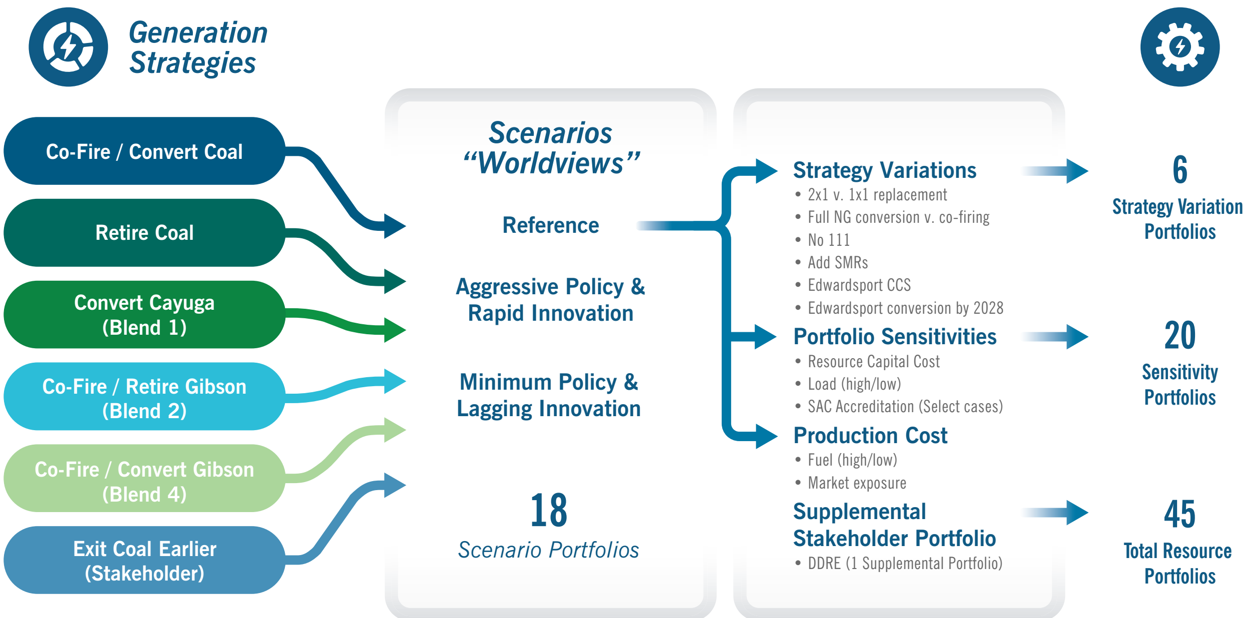
To further examine the detailed implications of specific resource decisions, and to test the sensitivity of model results to variability in individual inputs, the Company constructed additional strategy variations and conducted sensitivity analysis around both resource selection and portfolio operations. Importantly, one of these variations includes a portfolio optimized for a future in which the EPA CAA Section 111 Rule does not survive legal challenges, but the Company's base case assumptions otherwise hold (the "No 111" case). The results of the No 111 case inform the flexibility and potential pivot points included in the Short-Term Action Plan. The six generation strategies evaluated in these worldviews along with the No 111 strategy variation are summarized in Figure 7.

Figure 7: 2024 IRP Generation Strategies and No 111 Strategy Variation

<table>
<tr><th>UNIT</th><th>Convert/ Co-Fire Coal</th><th>Retire Coal</th><th>Blend 1</th><th>Blend 2</th><th>Blend 4</th><th>Exit Coal Earlier (Stakeholder)</th><th>No 111</th></tr>
<tr><td>Cayuga 1</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="6">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td colspan="2">Retire by 1/1/2030</td><td rowspan="2">NG Conversion by 1/1/2029</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Cayuga 2</td><td colspan="2">Retire by 1/1/2031</td></tr>
<tr><td>Gibson 1</td><td rowspan="2">Co-fire by 1/1/2030</td><td rowspan="4">Retire by 1/1/2032</td><td colspan="2" rowspan="2">Co-fire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">Retire by 1/1/2036</td></tr>
<tr><td>Gibson 2</td></tr>
<tr><td>Gibson 3</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Gibson 4</td></tr>
<tr><td>Gibson 5</td><td colspan="7">Retire by 1/1/2030</td></tr>
<tr><td>Edwardsport</td><td colspan="6">NG Conversion by 1/1/2030</td><td>NG Conversion by 1/1/2035</td></tr>
</table>

Note: Natural gas ("NG") conversion involves modifying existing infrastructure to use 100% natural gas fuel instead of coal for electricity generation. Co-firing involves infrastructure modification to use 50% natural gas fuel at the coal unit.

Figure 8: 2024 IRP Analytical Framework



Note: Carbon capture and sequestration ("CCS"); Deep decarbonization & rapid electrification ("DDRE")

The thorough 2024 IRP analysis centered around these six strategies ultimately yielded 45 potential resource portfolios along with additional supporting information derived from sensitivity analysis and stochastic risk assessment. The full analytical framework is illustrated in Figure 8.

Integrated Resource Planning Results

Reference Scenario results for the six generation strategies and the "No 111" strategy variation illuminate the trade-offs across potential paths forward. Strategies that keep more of the existing coal-fired steam units online (Convert/Co-fire Coal, Blend 4), achieving compliance with the EPA CAA Section 111 Rule by modifying these units to burn natural gas (either entirely or co-fired with coal), require lower levels of new resource additions. However, continued reliance on aging, relatively inefficient assets through the 2030s results in higher maintenance and compliance costs, increased cost risk due to MISO energy market exposure, and increased reliability risk. Strategies that retire most or all of the existing coal units by the deadline under the EPA CAA Section 111 Rule transition more rapidly to efficient, cost-effective resource mixes, but do so at the expense of greater near-term customer bill impacts and higher execution risk. The "blend" strategies explore various ways to balance these trade-offs, with Blend 2 separating itself from the other candidates as the most reasonable and prudent path forward.

Figures 9 and 10 show the cumulative resource additions and retirements and the energy mix for each generation strategy in the Reference Scenario and the "No 111" case at specific points in time.

Figure 9: Cumulative Supply-Side Resource Additions and Retirements for Generation Strategies in Reference Scenario and "No 111" Case (Installed GW, beginning of year)

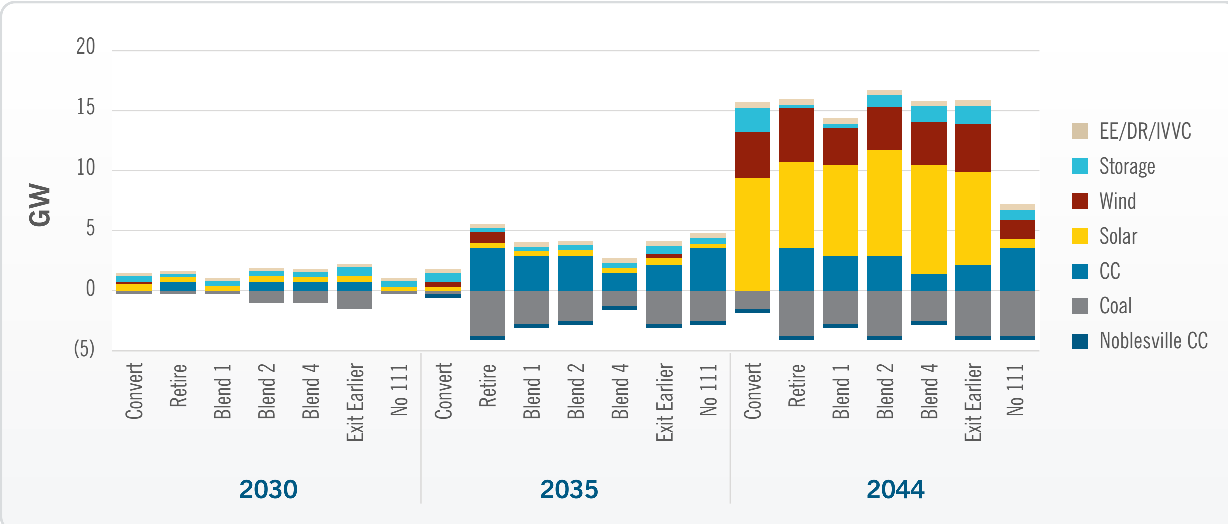
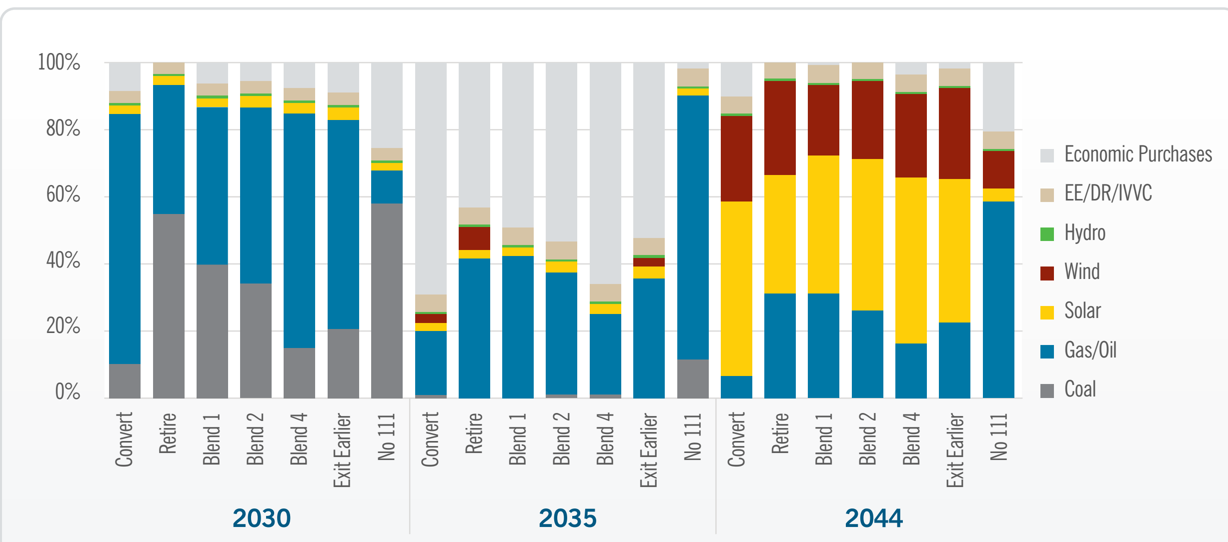


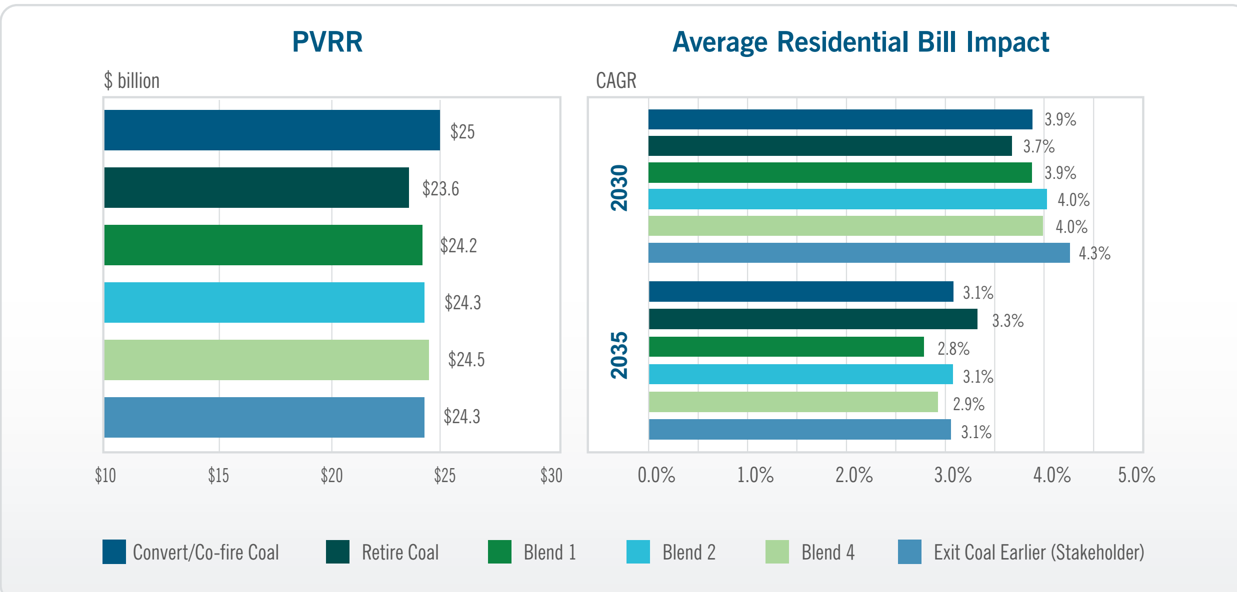
Figure 10: Energy Mix for Generation Strategies in Reference Scenario and "No 111" Case



Note: Energy Efficiency ("EE"); Demand Response ("DR"); Integrated Volt-Var Control ("IVVC")

Figure 11 shows the total portfolio cost, as measured by the present value of revenue requirements ("PVRR") over the planning period, and customer bill impacts by 2030 and 2035, as measured by the projected compound annual growth rate ("CAGR") for the average monthly bill of a typical residential household using 1,000 kilowatt-hours ("kWh") per month. These cost metrics include system fuel, operating and maintenance, and new resource capital expenditures for each candidate portfolio. Blend 2 achieves a reasonable balance between total cost (PVRR) and near-term customer bill impacts.

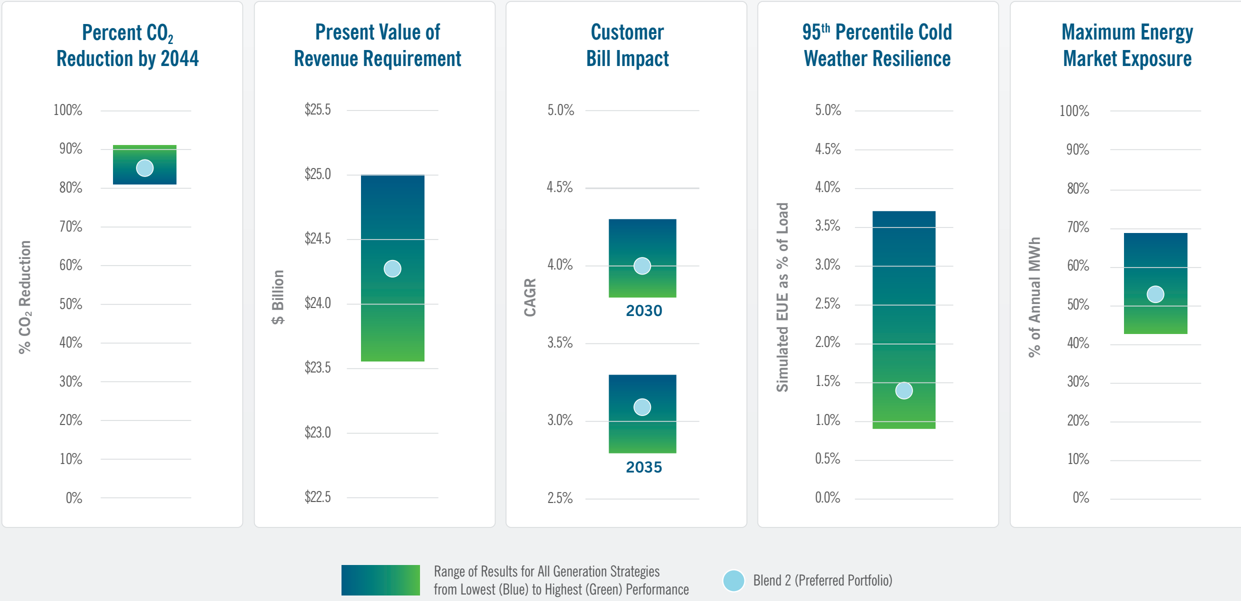
Figure 11: PVRR and Average Residential Customer Bill Impact Snapshots for Generation Strategies in Reference Scenario



Portfolio Evaluation

Balancing multiple objectives that are often in tension is a challenge, and avoiding negative outcomes can often be as or more important than achieving positive ones. Figure 12 shows where Blend 2, which the Company has identified as the Preferred Portfolio, falls in the range of results for CO_2 emissions reduction, cost, cold weather resilience, and energy market exposure across all generation strategies for the 2024 IRP. As discussed in Chapter 4 and Chapter 5, no generation strategy is consistently the best performer with respect to all of the planning objectives. Each strategy outperforms the group on certain metrics while underperforming on others. As Figure 12 illustrates, Blend 2 achieves better-than-average results for most metrics and never delivers the worst performance on any one metric.

Figure 12: Blend 2 Performance Within Range of Results for Selected Scorecard Metrics



Note: Expected Unserved Energy ("EUE") is stochastically simulated for Duke Energy Indiana as an islanded system with varying weather, unit outages, and economic conditions to indicate relative reliability, resiliency, and potential reliance upon the broader MISO market to meet customer demand.

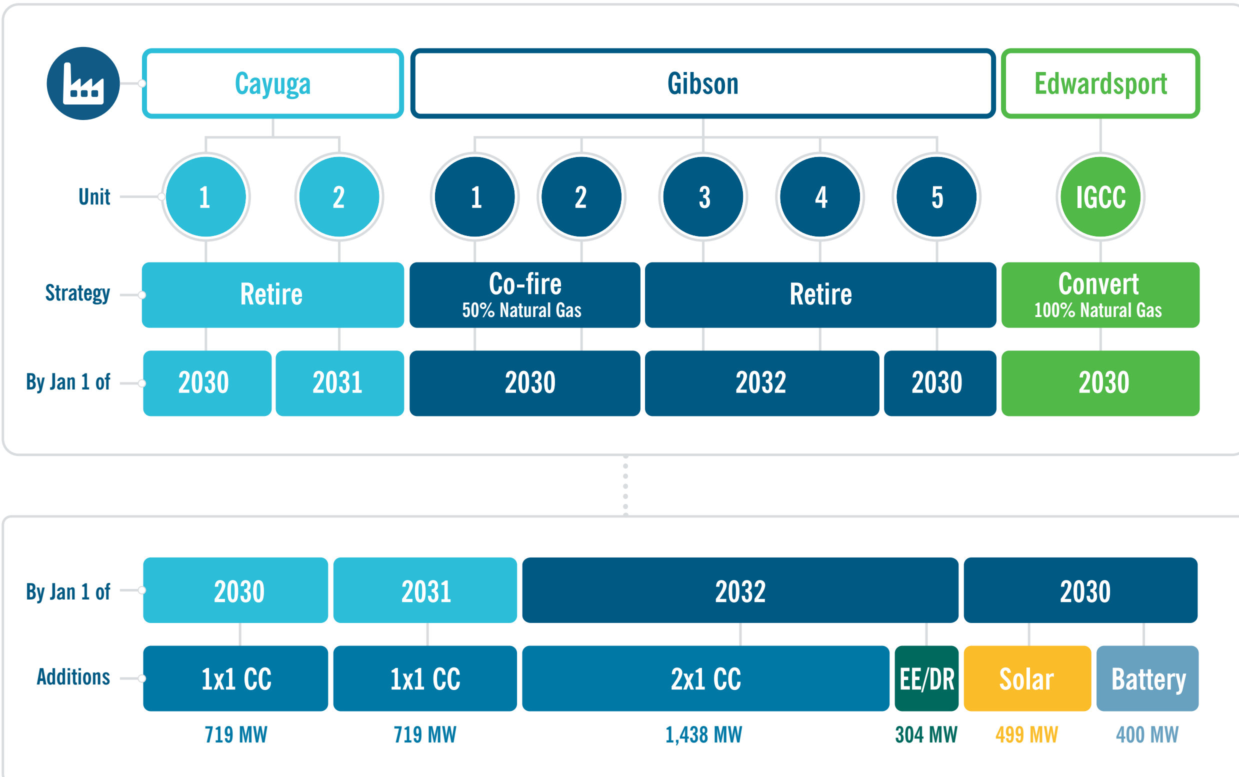
A Preferred Portfolio that Balances Planning Objectives

Duke Energy Indiana is committed to an orderly transition to cleaner energy that adds incremental generation to reliably support economic development and serve the needs of its growing customer base while replacing aging coal plants with a mix of diverse resources, including more flexible, equally reliable natural gas baseload generation, renewables, and energy storage, all with affordability top of mind. The Company has identified the Blend 2 Generation Strategy as the basis for the Preferred Portfolio in the 2024 IRP. This portfolio achieves compliance with the EPA's CAA Section 111(d) requirements but is flexible enough to allow for adjustments in the event the EPA rule is delayed or overturned. This strategy, described in more detail in Chapter 4 and Chapter 5, strikes the appropriate balance among the Five Pillars, mitigates risk with opportunities to adjust course as future conditions warrant, and adds new generating capacity to support robust economic development and customer growth in the state of Indiana.

By 2032, most projects initiated during the Short-Term Action Plan window for this IRP will be completed, coinciding with a critical compliance deadline for CAA Section 111(d). In this window, Blend 2 calls for over 2,800 MW of highly efficient combined cycle generation, nearly 500 MW of solar, and 400 MW of battery energy storage as shown in Figure 13 below. Additionally, the Company will implement more than 300 MW of energy efficiency and demand response programs. In total, Blend 2 would add over 1,100 MW of winter firm capacity, net of unit retirements, by 2032.

This mix will provide essential firm dispatchable capacity, enhance environmental sustainability, diversify the energy portfolio to mitigate risk, and provide for an affordable energy transition.

Figure 13: Summary of Blend 2 Strategy and Resource Additions by 2032

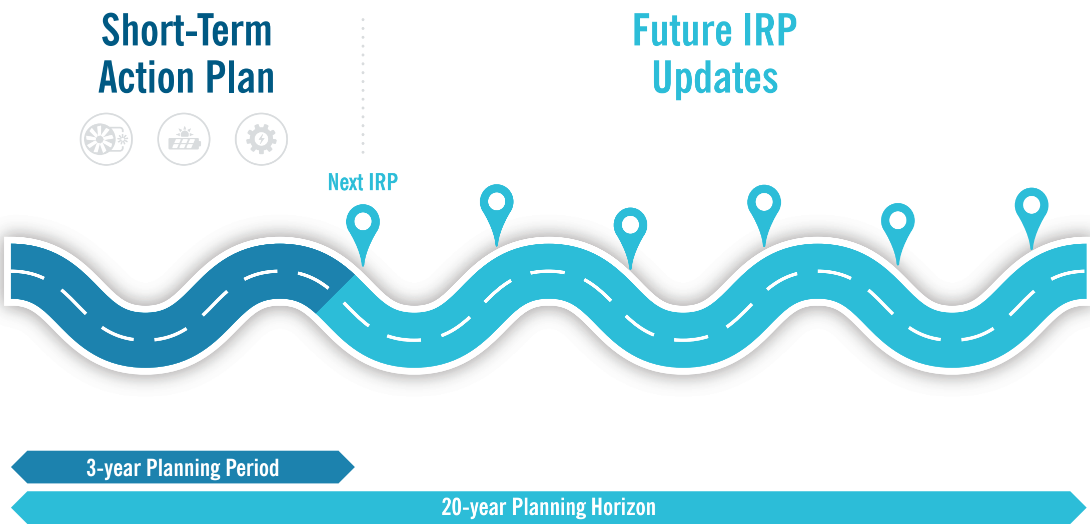


Short-Term Action Plan

The comprehensive resource planning analysis conducted by Duke Energy Indiana for the 2024 IRP identifies certain actions that are in the best interest of its customers across a wide range of potential future conditions, while also illuminating the signposts that will guide reasonable and prudent decision making over the next several years. This IRP is the latest iteration in the ongoing long-term resource planning process in which the Company updates its analysis and submits a new plan at least every three years. The Short-Term Action Plan covers activities that the Company will pursue over the three years between the development of this plan and the next.

Importantly, the Company is pursuing a path in its short-term action plan that has low or no regrets, with the ability to make adjustments if circumstances warrant. In addition to the activities outlined below and described in Chapter 6, the Company continually evaluates emerging opportunities to pursue prudent incremental supply-side and demand-side resources that can meet growing customer needs while balancing the planning objectives outlined in Chapter 2. The following short-term actions support the Preferred Portfolio and provide flexibility to adjust course as conditions change.

Figure 14: Short-Term Action Plan within a 20-Year Planning Horizon



Adding Capacity & Improving Reliability with Combined Cycle Generation at Cayuga

Since the early 1970s, the two coal units at Cayuga Generating Station (Cayuga 1 and 2) have provided reliable, affordable energy for Duke Energy Indiana customers. However, these units, now the oldest coal-fired generators in the Company's portfolio, are approaching retirement after six decades of service. In addition to requiring substantial maintenance work, continued operation of the Cayuga steam generators into the mid-2030s would be complicated by the need to comply with U.S. EPA's Effluent Limitation Guidelines and potentially add closed-cycle cooling to achieve compliance with sections 316(a) and 316(b) of the Clean Water Act, which govern discharge temperatures and intake structures, respectively. The age of the units, combined with the maintenance and compliance costs associated with continued operation, makes retirement and replacement of the existing Cayuga steam generators by 2030 and 2031 the reasonable and prudent course of action for the facility.

Replacing the coal units with two new 1x1 combined cycle generators will add over 400 MW of flexible, dispatchable generating capacity above the retiring capability at the site. Retiring these aging coal units and replacing them with more flexible and cleaner burning natural gas combined cycle units will provide environmental benefits by lowering CO_2 and nitrogen oxide ("NOx") emissions, eliminating sulfur dioxide and mercury emissions, and removing the current thermal discharge to the Wabash River. It will also increase reliability and resource adequacy of the Duke Energy Indiana generating fleet, providing flexible dispatchable generation needed in the MISO market and eliminating an ongoing risk of derates due to river temperatures. Additionally, the Cayuga site is well situated for natural gas generation, due to its proximity to interstate pipelines and a robust source of natural gas supply and firm transportation. Finally, the path promotes affordability through lowering ongoing operating costs, eliminating large environmental compliance costs associated with the aging coal units, and repurposing existing infrastructure at the Company's coal sites.

The Company has begun preliminary development of these projects, including filing an application for an air permit and entering the MISO interconnection queue for the incremental generation. Duke Energy Indiana plans to file a Certificate of Public Convenience and Necessity ("CPCN") with the Indiana Utility Regulatory Commission ("IURC" or the "Commission") application for these projects in the upcoming months.

Enhancing Plan Flexibility with Gas Supply to Gibson

The five coal-fired steam generators at Gibson have a combined generating capacity of nearly 3,200 MW, of which over 2,800 MW are owned by Duke Energy Indiana. The 2024 Preferred Portfolio includes the following short-term actions at Gibson to support compliance with CAA Section 111(d) requirements.

- **Units 1 and 2:** Upgrade to allow co-firing of natural gas and coal fuels, enabling the units to run at up to 50% of full capacity on natural gas alone. Of the Gibson generators, units 1 and 2, which have the newest emissions controls and largest precipitators, are best positioned to maintain coal-burning capability. Adding natural gas as a fuel option will reduce emissions from these units while allowing continued operation through 2038 in compliance with CAA Section 111(d). In addition to the natural gas upgrade, certain maintenance projects must be completed to allow these units to operate into the late 2030s

- **Units 3 and 4:** Retire and replace with a 2x1 combined cycle generator by 2032. Replacing these existing steam units with a highly efficient, flexible gas-fired generator will improve environmental sustainability, reduce reliability and resource accreditation risks, and add nearly 200 MW of incremental firm capacity above the retiring generating capability.

- **Unit 5:** Retire by 2030, consistent with the unit's expected depreciable life.[3]

Importantly for action at Gibson Station, Duke Energy Indiana will closely monitor legal and regulatory developments related to the contested EPA rule governing greenhouse gas emissions under CAA Section 111(d). Indications of the likely success or failure of legal challenges to the rule constitute critical signposts that could indicate the need to adjust the Short-Term Action Plan. In the event of any changes to compliance requirements or deadlines under the rule, the Company could delay taking action to co-fire Gibson units 1 and 2 until regulatory requirements were finalized. If the rule is overturned, the Company could continue to operate Gibson units 1 and 2 on coal through 2035, consistent with the 2021 IRP's moderately paced clean energy transition and the "No 111" Portfolio evaluated as part of the 2024 IRP.

Similarly, the Company could delay action on Gibson units 3 and 4 if deadlines for compliance with CAA Section 111(d) requirements are delayed. Regardless of the final outcome for the rule, the cost of new combined cycle generation to replace Gibson units 3 and 4 will be an important consideration. Over the next year, Duke Energy Indiana will engage with equipment suppliers and engineering, procurement, and construction ("EPC") contractors to monitor the costs and lead times for new generation projects, preserving the option to pivot to conversion of Gibson 3 and 4 to 100% natural gas fuel if market conditions or

3 Conversations regarding the joint owner implications of this anticipated retirement are ongoing.

customer load needs dictate that option to be in the best interest of customers.

The Company plans to repurpose the Gibson site for this new generation, which allows for the continued use of existing infrastructure, including transmission interconnections, and allows the Company to continue its investment in the local community, providing jobs and tax base. Securing firm natural gas fuel supply to the Gibson site is a requirement for any of the potential resource options described herein. Duke Energy Indiana will take the appropriate steps to ensure that gas fuel is available at Gibson when it is needed.

Edwardsport Integrated Gasification Combined Cycle Provides Valuable Optionality

With an in-service date of 2013, Edwardsport IGCC Plant is Duke Energy Indiana's newest and cleanest coal plant, and it continues improving operations and lowering costs. This facility provides essential dispatchable capacity, the value of which will continue to increase as renewables make up a greater portion of the MISO resource mix. It supports system resiliency with on-site fuel storage and the optionality of operating on coal, natural gas or a combination of the two. Edwardsport IGCC is well situated today to comply with ever increasing environmental regulations, such as stricter coal ash residual handling, NOx, mercury and particulate emission limitations, and clean water act regulations, and it holds the promise of cost-effective compliance with greenhouse gas emissions, like the EPA's CAA Section 111(d) rule through either conversion to natural gas operations or the addition of carbon capture, and sequestration ("CCS") by the early 2030s.

Given the substantial uncertainty around the future timing and extent of greenhouse gas regulations, including EPA's new CAA Section 111(d) rule, as well as future fuel prices, the cost of new resources and the pace at which they can be added to the system, and accelerating load growth driven by economic development, Duke Energy Indiana remains confident in the value of the flexibility and optionality provided by the Edwardsport IGCC. If, however, EPA's CAA Section 111(d) rule persists as it is currently written, the Company will maintain optionality by (1) continuing to advance studies of the feasibility, risks, and costs of deploying CCS at Edwardsport by 2032, and (2) remaining prepared to retire the gasifiers by 2030 should that ultimately prove to be a reasonable and prudent decision.

Notably, retirement of the coal gasification portion of Edwardsport IGCC in 2030 or 2035 would be well in advance of its projected end of useful life in 2045. As such, Duke Energy Indiana would require a Commission order that assures recovery of and on the retired assets in accordance with its CPCN for the plant in order to move forward with a natural gas conversion project at the plant.

In the event the EPA CAA Section 111 Rule is delayed or repealed, the Company could continue to operate the gasifiers as it monitors regulatory and market conditions. As described in the 2021 Duke Energy Indiana IRP, a decision to move to full-time natural gas operations at Edwardsport IGCC is virtually a permanent decision and would be very difficult to reverse. Required air permitting changes, the loss of specialized workforce for the gasification process, coal contract issues, and operational challenges with restarting the plant on coal would all make a reversal highly complex and costly. Until such time that a change occurs, the Company will continue to look for opportunities to maximize the value of Edwardsport IGCC's flexibility to operate on coal, natural gas, or a combination of the two.

Renewables & Storage Contribute Needed Capacity & Energy this Decade

To meet more immediate needs for incremental energy and capacity, Duke Energy Indiana plans to add approximately 500 MW of solar and 400 MW of battery energy storage to the portfolio by 2030. This includes the 199 MW Speedway Solar project that is scheduled to be completed in 2025. The remaining capacity will be procured through the ongoing evaluation of bids received in response to the request for proposals in the late 2024 through mid-2025 time frame. In addition to meeting customers' near-term needs for additional energy and capacity, these renewable and energy storage resources will help improve the environmental sustainability of the portfolio and enhance resource diversity.

The 2024 IRP analysis indicates that renewable energy and energy storage resources will make up a large part of the Company's energy mix starting in the mid-to-late 2030s as the relative economics of those resources improve. Duke Energy Indiana will continue to monitor the market and regulatory changes that influence the economic value of renewable and storage resources in between IRPs and in future IRPs. If circumstances warrant, the Company could accelerate some of the larger solar, wind and storage additions that are included in the Preferred Portfolio in the late 2030s to earlier in the plan.

Continued Investigation of Advanced Nuclear for Future Around-the-Clock, Carbon-Free Generation

Although nuclear resources were not economically selected in the 2024 IRP, advanced nuclear technologies such as small modular reactors ("SMR") offer the potential to add considerable value for customers. The potential for significant cost declines as SMR technology and supply chains mature, combined with the possibility of delivering reliable, around-the-clock, carbon-free generation in the future, makes it prudent for Duke Energy Indiana to continue to advance early studies and maintain advanced nuclear as a viable option in future resource plans. The Company plans to continue its work with Purdue University related to the feasibility of SMR and advanced nuclear generation, closely monitoring the evolving technology, the regulatory framework, stakeholder education, and costs as the initial SMR demonstration projects are brought online. It is prudent for the Company to continue these investigations given the long lead time associated with nuclear deployment.

Managing Demand with Customer Programs

Duke Energy Indiana recognizes the importance of customer programs in managing reliability on the grid. From load flexibility (or demand response) programs to help manage peaks and intermittency of the grid, to energy efficiency programs designed to lower energy consumption to electric vehicle programs to facilitate and manage the impacts of transportation electrification, Duke Energy Indiana is committed to continuing to offer a suite of programs to customers while progressing a reliable and resilient energy future.The Company contributes as appropriate in IURC, MISO, and Federal Energy Regulatory Commission policy areas that impact customer programs, benchmarks with other utilities, and stays abreast of vendor technologies to protect and grow opportunities for customers to participate.

Figure 15: Snapshot of Major Short-Term Actions

Combined Cycle

- **2024-2025:** File CPCN for two Cayuga 1x1 CCs, 719 MW each, to be in-service by beginning of 2030 and 2031.
- **Completed in 2024:** Submitted air permits, MISO Generator Replacement Requests ("GRR") for Cayuga units 1 and 2, and incremental capacity study requests.
- **2025–2026:** File CPCN for Gibson 2x1 CC at 1,438 MW to be in-service by 2032, submit air permits, submit MISO GRR for Gibson units 3 and 4.

Solar

- **2024-2025:** Procurements targeting approximately 300 MW of solar to be in-service by 2030.
- **2025:** Speedway Solar (199 MW) to be placed in-service by end of year.

Storage

- **2024-2025:** Procurements targeting 400 MW of battery storage to be in-service by 2030.

Energy Efficiency

- **2025:** File for new three-year energy efficiency programming.
- **2025-2027:** Continue to grow existing programs and introduce new cost-effective programs.

Demand Response & Voltage Optimization

- **Continue** to grow existing demand response programs and introduce new cost-effective programs, apply lessons learned to Savings on Demand program.
- **Continue** deployment of IVVC to additional circuits.
- **Monitor** changes to MISO and Federal Energy Regulatory Commission ("FERC") policies, participate in forums and utility groups.

Natural Gas Conversion/ Co-firing

- **2025-2026:** Complete Gibson 1-4 boiler studies for natural gas co-firing, conversion.
- **Complete** Edwardsport CCS Feed Study by mid-2026.
- **2026-2027:** Determination of Edwardsport natural gas conversion or CCS path and timing.

SMR

- **Continue** work with Purdue University, other preliminary discussions and activities related to advanced nuclear feasibility.
- **Monitor** technology developments.

Rate Design

- **2024-2027:** Ramp up implementation of Green Source Advantage, other voluntary customer clean energy programs.
- **If approved**, implement new time-of-use rates and electric vehicle programs.

Duke Energy Indiana will pursue these short-term actions and continue to monitor the energy landscape, checking and adjusting as warranted to ensure it is prepared to serve its customers with reliable, affordable, and increasingly clean energy now and into the future.

Chapter 1: Planning for the Future Energy Landscape

Highlights

- The Integrated Resource Plan is Duke Energy Indiana’s proposed road map for transitioning to cleaner energy without compromising reliability of service, energy affordability or the power demands of a growing region.
- As the energy landscape transitions, Duke Energy Indiana’s long-term integrated resource planning faces challenges, such as growing customer load, stringent environmental regulations, the growth of intermittent renewable generation, the introduction of new technologies, and the retirement of aging traditional baseload resources.
- Key elements of a balanced and orderly transition include replacing aging generation with new, more flexible baseload options, investing in pipeline and grid infrastructure, adding renewables and energy storage, and implementing its robust energy efficiency and demand response portfolio to ensure the delivery of reliable and increasingly clean electricity while keeping costs as low as possible for customers.

Landscape

In this Chapter, Duke Energy Indiana (or the “Company”) summarizes the various ways the changing energy landscape has influenced its 2024 Integrated Resource Plan (“IRP”) inputs and results. It addresses areas such as load growth resulting from exceptionally strong economic development and electrification, the planned retirement, modernization, and addition of baseload resources needed to ensure reliability of a transitioning energy grid, ever-changing regional transmission organization rules and procedures, historic tax credits resulting in the addition of solar, wind, and storage resources, the significant impact of new environmental rules, technology advancements, and consumer trends. This Chapter then summarizes the key elements needed for Duke Energy Indiana’s reliable and balanced energy transition and concludes with a recap of the new issues and improvements incorporated in the IRP.

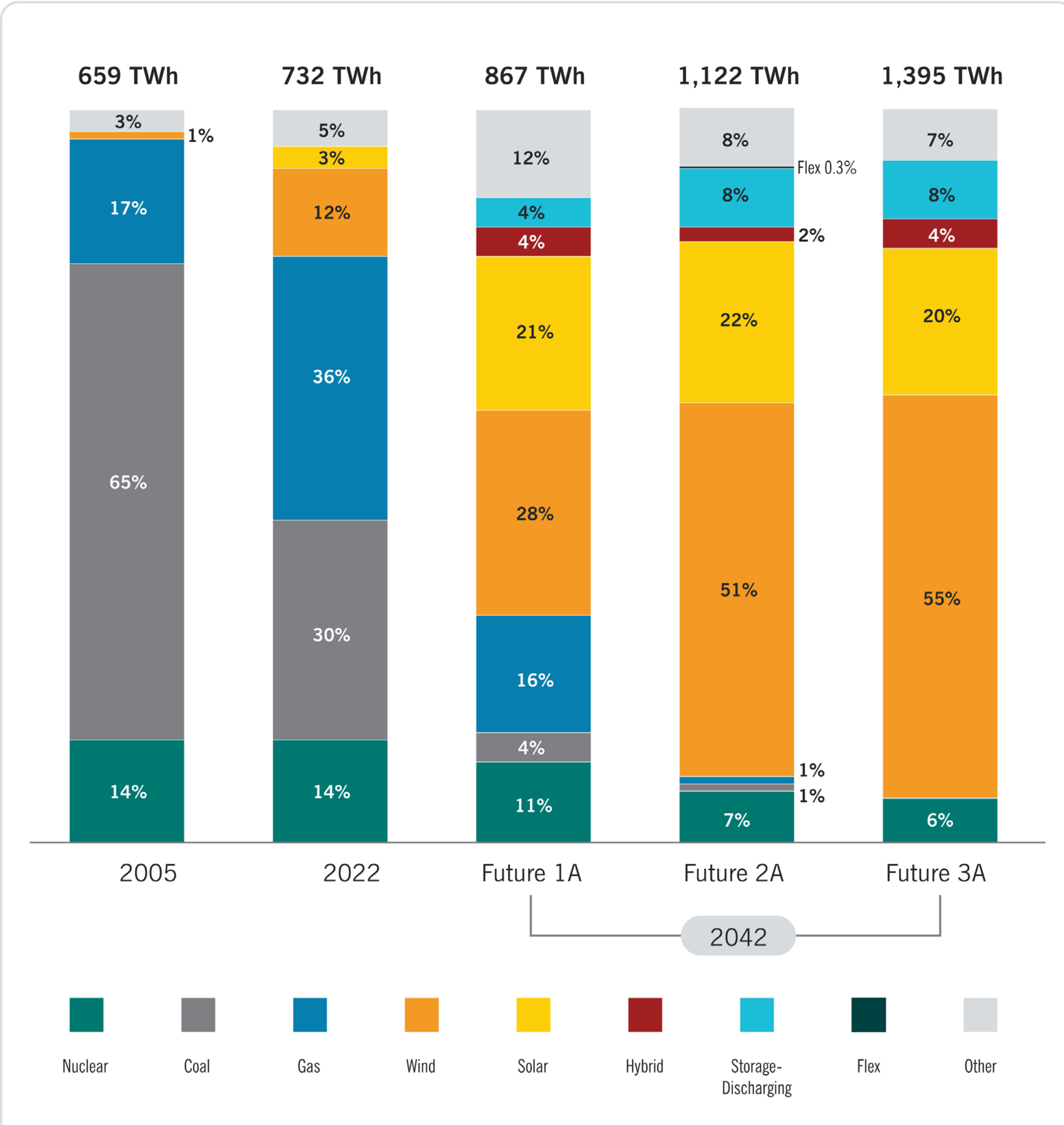
Energy Transition in Progress

Duke Energy Indiana enters into this IRP planning process with the U.S. electric industry in the midst of significant transition. The industry is experiencing a rapidly changing resource mix including the addition of intermittent renewable resources, the introduction of new technologies, and the retirement of traditional baseload resources. At the same time, the industry is experiencing unprecedented energy demand growth and increasing uncertainty from environmental regulations.

Duke Energy Indiana is a member of the Midcontinent Independent System Operation ("MISO"), established in 2001, an independent entity that oversees the flow of wholesale electricity across the Midwest and the southern United States. MISO manages the reliable flow of electricity in its regions, facilitates the buying and selling of electricity through energy and capacity markets, and plans for regional grid expansion.

A look at MISO members' generation fleets over time demonstrates the transition away from aging coal-fired generation to natural gas and renewable resources. MISO has forecasted the potential generation fleet mix in three potential "futures" representing a range of economic, political, and technological possibilities. As shown in Figure 1-1 below, the forecasted generation mix in each of these futures depicts a further transition away from fossil fuel generation and toward variable energy resources including solar, wind, and storage.

Figure 1-1: MISO's Forecasted Generation Mix Transition

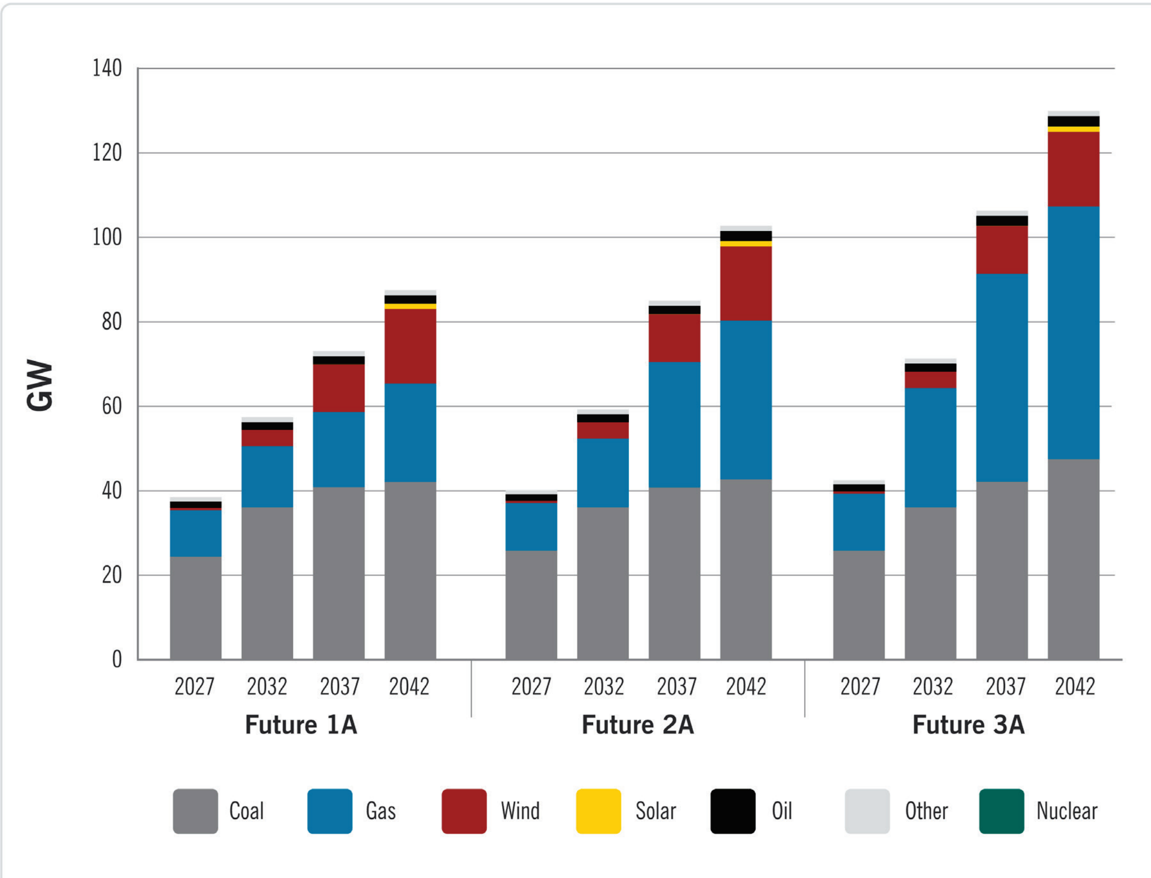


Note: Figure 1-1 depicts MISO's resource expansion analysis for a cohort of three future planning scenarios, which represent a range of economic, political, and technological conditions over the MISO's study period. Expressed in terawatt hours ("TWh").

Source: MISO, MISO Future Report – Series 1A, Figure 1: Overview of MISO's Generation Fleet Mix Transition, November 1, 2023, available at https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

Much of the transition since the 2000 timeframe has revolved around the retirement of aging coal plants driven by the increase in environmental regulations, as well as the improving economics of alternative generation sources like natural gas and renewables. MISO forecasts the coal retirement trend to continue in all future scenarios, as depicted in Figure 1-2 below.

Figure 1-2: MISO's Forecasted Cumulative Generation Retirements



Note: Expressed in gigawatts ("GW").
Source: MISO, Future Report – Series 1A, Figure 12: Total Retirements per Future (Cumulative by Year), Equal to Age-Based + Base, November 1, 2023, available at https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

As MISO forecasts the transition away from fossil fuels and toward renewables to continue, it has also noted that, during the transition, the MISO region will need to rely upon generation with attributes needed to support system adequacy, flexibility and system stability of the grid, as part of its reliability imperative. As utilities and states decarbonize their resource fleets, MISO explains:

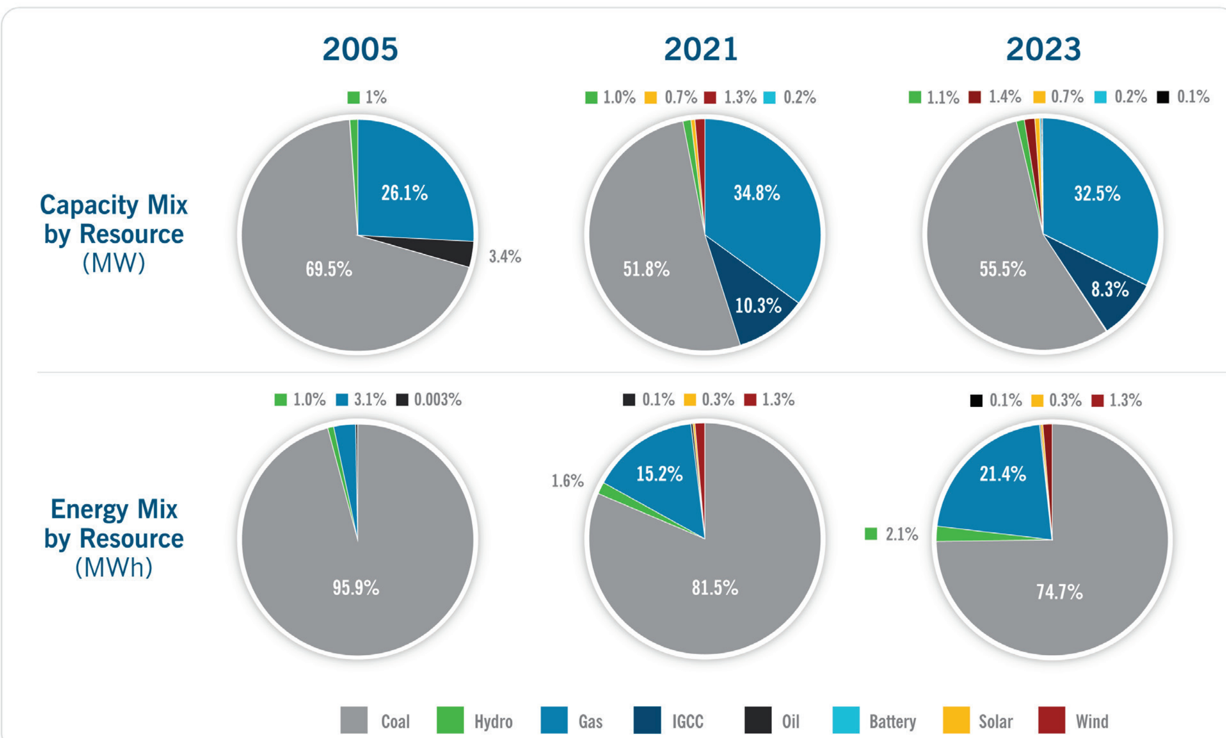
> A key risk is that many existing 'dispatchable' resources that can be turned on and off and adjusted as needed are being replaced with weather-dependent resources such as wind and solar that have materially different characteristics and capabilities. While wind and solar produce needed clean energy, they lack certain key reliability attributes that are

needed to keep the grid reliable every hour of the year… Until new technologies become viable, we will continue to need dispatchable resources for reliability purposes.[1]

Duke Energy Indiana Generation Transition

Within the broader context of the MISO region, Duke Energy Indiana has been steadily transitioning its generation mix. Once reliant on coal-fired generation for about 70% of its energy needs, as seen in Figure 1-3 below, Duke Energy Indiana has diversified its portfolio over time. This IRP marks a continuation of a measured transition to cleaner energy sources, while keeping power supply reliability and customer affordability at the forefront of resource planning. This orderly transition first impacted older and smaller coal-fired generating plants that faced rising environmental compliance and maintenance expenditures. Since the early 2000s, Duke Energy Indiana has repowered its Noblesville Station with natural gas, retired its old Edwardsport Station, as well as the Wabash River and Gallagher coal plants, and replaced them with the dual-fuel Edwardsport integrated gasification combined cycle ("IGCC") plant, natural gas combined cycle plants, and wind and solar resources.

Figure 1-3: Duke Energy Indiana Generation Profile Over Time



Note: Energy mix is shown as percent of total megawatt-hours ("MWh") generation from Duke Energy Indiana portfolio resources. Capacity mix is shown as percent of total installed capacity. IGCC is reflected as coal in the energy mix. 2044 mix is based on the 2024 IRP Preferred Portfolio.

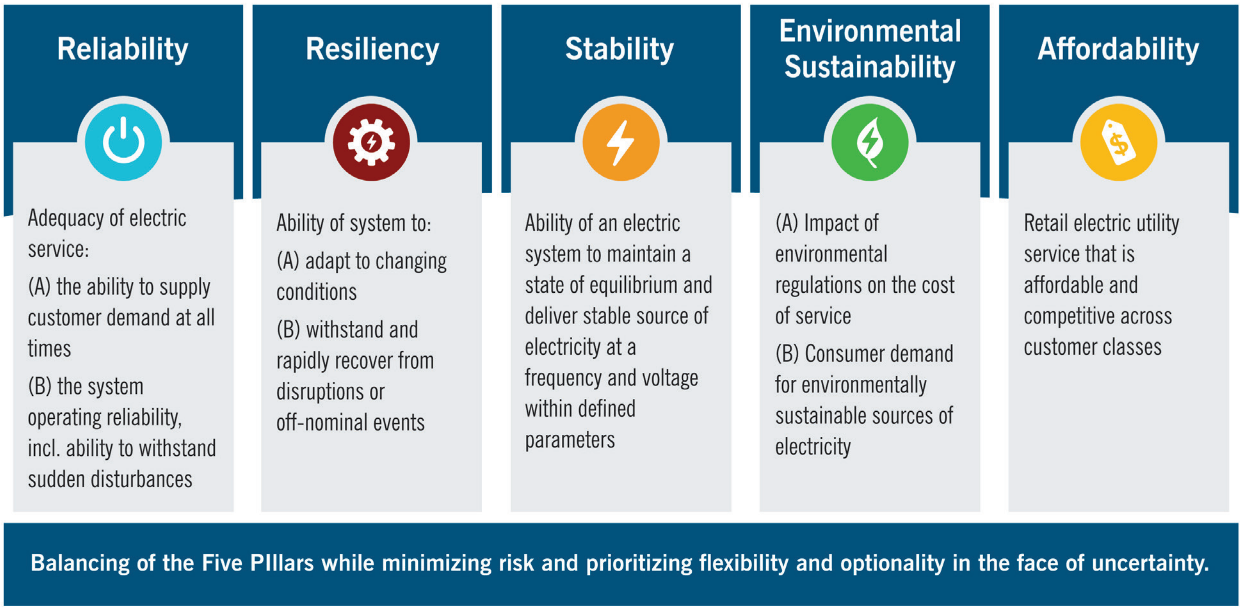
[1] MISO, MISO's Response to the Reliability Imperative, February 2024, available at https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

Duke Energy Indiana's transition from reliance upon emissions-intensive generating resources is reasonable, prudent, and consistent with risk mitigation practices throughout the broader electric power industry. However, this is a transition that must be managed carefully. The energy landscape is rapidly changing with the convergence of robust economic development and anticipated load growth, tightening capacity accreditation policies, and stricter environmental requirements. During this transition, the Company must heed MISO's reliability imperative and ensure the replacement and addition of reliable, dispatchable generation as part of a balanced portfolio. The Company is mindful of the need for a reliable grid at every hour of every day and all seasons of the year, including during extreme weather events. As a result, this IRP has a strong emphasis on the need for development and investment in the near and intermediate terms, as well as retaining flexibility to meet evolving conditions in the long term.

Challenges Impacting Planning

Duke Energy Indiana must plan a portfolio of resources designed to provide reliable, affordable and increasingly clean generation to meet the needs of its growing customer base. Helpfully, the state of Indiana has recently undertaken a multiyear energy policy process to provide guidance to utilities as they make this transition. The result is two reports from the General Assembly's 21st Century Energy Policy Development Task Force and subsequent legislation establishing five pillars of Indiana energy policy: Reliability, Resiliency, Stability, Environmental Sustainability and Affordability (the "Five Pillars"). A balance of all Five Pillars is required as the Company plans its 20-year IRP and its eventual requests to implement its Short-Term Action Plan through certificates of public convenience and necessity and other resource approval filings at the Indiana Utility Regulatory Commission. In addition to focusing on the Five Pillars, the IRP process requires an examination of risk and uncertainty as shown in Figure 1-4 below. Duke Energy Indiana has designed its decision-making criteria with these six factors in mind, analyzing portfolio options for their impact on customer rates, diversity of supply, emissions reductions, availability at times of peak need, and other key planning objectives. Additionally, with the focus on reliability needed during the critical time of energy transition, Duke Energy Indiana has conducted an enhanced reliability evaluation to measure the relative ability of portfolios to provide sufficient energy to the grid and be available during a range of weather and generation outage conditions.

Figure 1-4: Balancing the Five Pillars with Consideration of Risk and Uncertainty



The energy landscape is changing in significant ways and several changes directly influence long-term planning inputs and results as summarized in Table 1-1 below. In the next 20 years, forecasted load has increased materially due to robust economic development levels not seen in previous planning cycles and a continuing trend of electric vehicle adoption. The MISO planning reserve margin to provide physical power supply adequacy and reliability has increased and accredited capacity value has decreased, accounting for extreme weather needs and less reliance on neighboring systems. More broadly, an active environmental policy and regulatory landscape results in more stringent environmental regulations, driving the need to plan for an increasingly clean set of resources. Furthermore, economic and financial inputs are impacting resource costs in the IRP. The Inflation Reduction Act of 2022 (“IRA”) provides for extended clean energy production and investment tax credits that directly benefit customers along with $67 billion in additional federal clean energy grants,[2] and the Infrastructure Investment and Jobs Act (“IIJA”) provides for $65 billion in transmission and grid investment and over $7 billion in electric vehicle charging investment.[3] At the same time, upward pressure is impacting resource costs as inflation and macroeconomic uncertainty have increased and supply chain challenges have impacted all resources. Finally, the timing and magnitude of technology advancements and customer trends also drive planning assumptions.

[2] The White House, Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act’s Investments in Clean Energy and Climate Action, Version 2, January 2023, available at https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/.

[3] The White House, Fact Sheet: The Bipartisan Infrastructure Deal, November 2, 2021, https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/23/fact-sheet-the-bipartisan-infrastructurelaw-will-revitalize-main-street/.

Table 1-1: Changing Energy Landscape and Related Plan Implications

Change	Drivers	Plan Implications
Load Growth	• Robust economic development and electric vehicle load growth	• More resources needed to serve growth • Increased emphasis on load growth sensitivities in modeling
Reliability Amid Fleet Transition	• Need for 24/7 resources to replace retiring dispatchable generation • Increasing renewables due to IRA incentives • Extreme weather events	• More resources needed to maintain demand and energy needs 24/7 • Need for natural gas during transition • Diversity of resources preferred • IRA incentives modeled • Enhanced reliability modeling
Policy and Regulatory Landscape	• The Environmental Protection Agency (“EPA”) Clean Air Act (“CAA”) Section 111 May 2024 Final Rule (“EPA CAA Section 111 Rule”) regulating greenhouse gas emissions and other EPA regulations challenging coal plants • MISO reliability imperative, seasonal construct, accreditation changes	• Balance of Five Pillars • Increased complexity in modeling • Pursue least regret options in light of uncertainty
Advanced Technology Availability	• Clean energy technology not advanced on timeline to reliably replace aging coal generation	• Investments in battery storage • Study of carbon capture and sequestration (“CCS”) • Preliminary studies and monitoring of advanced nuclear • Study and monitoring of hydrogen advancements • Monitor risks and signposts and check and adjust in short-term action plan

Considerations Impacting Affordability of Replacement Generation	• IRA/IIJA incentives • Inflation, financing, and supply chain constraints • Longer infrastructure siting and permitting timelines for new generation/pipelines • MISO queue and transmission infrastructure challenges • Fuel availability and assurance challenges	• Upward cost pressure caused by supply chain constraints and accelerated transition due to federal environmental rules • Including incentives and real-world constraints on generation timing in analytics • Moderate transition within confines of environmental rules to minimize impact on affordability • Repurposing existing generation sites for new more flexible and reliable generation
Customer Trends	• Customer desire for cleaner energy options • Increased behind-the-meter generation and energy efficiency and demand response	• Inclusion of behind-the-meter generation, energy efficient and demand response in plan • Monitor real-world impact of voluntary customer programs

Load Growth

After years of slow load growth, recent trends in data centers for artificial intelligence, batteries for electric vehicles, and onshoring of manufacturing under the Creating Helpful Incentives to Produce Semiconductors ("CHIPS") and Science Act have begun to impact load forecasts. For Duke Energy Indiana, approximately 300 MW of large economic development projects have been included in the base load forecast by 2030. The size, scale, and speed of economic development of larger projects have dramatically increased over the past several years. As load increases over time, total annual energy consumption is projected to outpace peak demand growth over the planning period. This increase in load factor is driven by a growing industrial sector, which requires firm, dispatchable resources to provide dependable, around-the-clock energy supply. New residential customers are also coming onto the system through continued population growth. Finally, by 2044, the impacts of forecasted growth of electric vehicle adoption add another increase in projected load, as commercialization and economic development of transportation electrification advances with federal and state policy and incentive support. As a result, in the load forecast, total retail sales are expected to increase at an annual compound growth rate of 1.2% through the 20-year planning period.

This IRP reflects increased load growth and includes sensitivity analyses that push the boundaries of traditional load growth estimates. Details on load forecasts and related analysis and assumptions can be found in Appendix D (Load Forecast).

Reliability Amid Fleet Transition

Duke Energy Indiana maintains a reserve margin as required by MISO to ensure reliability during unexpected conditions related to extreme weather (especially during extreme hot or cold days), variance around economic load growth projections, and generation unplanned outages. As the region's energy needs grow due to economic development, population increase, and the adoption of electric vehicles, resource adequacy to ensure reliability at all times and in all seasons must keep pace.

Extreme weather events and the transition to increased intermittent generation have heightened focus on resource adequacy and reliability across the MISO region. As the resource mix and those of neighboring operating areas transition from conventional dispatchable baseload generation, like coal, to variable-energy renewables and energy-limited storage, all operating entities will be closely evaluating and adjusting long-term planning needs to provide adequate energy and capacity. Maintaining reliability is critical to the success of the energy future, and that is why MISO has put an increased emphasis on its reliability attributes needed during the transition, many of which can be met by the addition of flexible new natural gas generation. At the same time, the state of Indiana has placed increased importance on resource adequacy through enactment of the Five Pillars of energy policy, requiring utilities to balance reliability, resiliency, stability, affordability and environmental sustainability in their resource planning, and ensuring that utilities do not rely too heavily on the MISO capacity market to meet their customers' needs.

For this IRP, Duke Energy Indiana modeled updated MISO accreditation rules, including reserve margin changes. Additionally, Duke Energy Indiana performed an enhanced reliability evaluation to examine the various portfolios' ability to serve the energy needs even during extreme weather events. See Appendix E (Reliability & Resource Adequacy) for more details on this analysis.

Policy and Regulatory Landscape

In recent years, there have been major changes in the energy policy and regulatory landscape that are impacting integrated resource planning. Many of these changes are driven by environmental policy at the federal level. There have been new environmental rules related to coal combustion residual handling, closure and monitoring, mercury, NOx, particulates and SO_2 emissions, cooling water intake and discharge, and notably greenhouse gas limitations. The rules often are the source of increased uncertainty in the planning space. Draft rules can change before they are finalized and final rules are almost always challenged in the courts, sometimes leading to modifications or even complete reversal. Political party changes can also impact the ultimate effectiveness of environmental rules. Yet, the estimated costs and operational impacts associated with these rules must be reflected in the IRP modeling, along with scenario and sensitivity analysis which attempts to account for the uncertainty. Recent trends in environmental rules, along with the aging infrastructure, are leading utilities to consider retirement of coal generation in particular due to increased costs of compliance and limited flexibility with compliance options.

At the same time, policies are incentivizing investments in technology development (both at large scales and in distribution and consumer energy integration), economic development, renewables, transportation electrification and energy efficiency.

For instance, recent passage of the IIJA and IRA provide historic levels of investment and tax incentives for the grid, nuclear generation, renewables, energy storage, hydrogen, CCS, energy efficiency, and vehicle electrification. Federal and state actions continue to show interest in advancing transportation electrification, driving investments and economic development in industrial sector growth for electric vehicles and components, such as battery manufacturing and vehicle assembly. The IRA is providing significant investment incentives for CCS and clean hydrogen production, and the IIJA allocated billions for the Department of Energy ("DOE") to develop regional hydrogen hubs. This active policy and regulatory landscape require the Company to balance planning objectives and the scope and timing of planning inputs and assumptions as further described in Chapter 2 (Methodology) and Chapter 3 (Key Assumptions).

Addressing environmental justice and community impacts related to anticipated plant retirements and the siting of new resources is increasingly being integrated into policy and regulations, as seen in components of the IRA and IIJA. These activities occur as part of execution activities and project-related work, and the Company has developed environmental justice principles and protocols to guide siting activities in facilitating meaningful local engagement for infrastructure projects.

Next, given the trend toward more intermittent generation on the grid and retirement of traditional baseload generation, MISO and the other regional transmission organizations have implemented recent changes to ensure reliability and resource adequacy during the transition. Recent changes to the accreditation of traditional resources through MISO's Seasonal Accredited Capacity ("SAC") construct have resulted in lower accreditation for existing generation. Future proposals by MISO, including the Direct Loss of Load ("DLOL") methodology, further limit the accreditation of renewable resources. Changes such as the reliability-based demand curve, intended to provide a stronger incentive for the construction of new generation, will likely result in upward pressure of costs of capacity from the MISO planning reserve auction. These policy changes create additional challenges for utilities in meeting current and increasing future load requirements.

In Indiana, recent policy changes make clear the desire for utilities to balance several factors: reliability, resiliency, stability, affordability and environmental sustainability – the Five Pillars. In an integrated system, sometimes all these policy and technology changes align on both objective and timing, and other times run counter to one another, resulting in trade-offs in cost, risk, timing, reliability, and execution the Company must weigh and balance in its long-term resource planning.

Although there is a policy focus on providing incentives for advanced cleaner technologies and regulatory incentives to transition away from fossil fuels and to cleaner energy resources, the availability of the advanced technologies at scale has not materialized as fast as once predicted. This leaves utilities today with limited choices to serve increasing load, such as a combination of new natural gas resources, renewables, and storage in the near and mid-terms, and the need to focus on advanced technologies such as long-duration storage, CCS, hydrogen and advanced nuclear technologies in the long-term. In the face of change and uncertainty, the Company strives to select choices that have the fewest regrets no matter the ultimate outcome, focusing on diversity, flexibility, and an “all of the above” approach to resource planning.

Advanced Technology Availability

A key element to a reliable energy transition is a complementary set of technologies that provide customers with risk and cost hedges across the portfolio. A balanced energy transition relies upon a diverse power supply that can meet growth and future needs of the system as aging assets are retired. Duke Energy Indiana is involved and closely monitoring various technology advancements, some of which are integrated into planning assumptions and others not yet as detailed in Appendix F (Supply-Side Resources). There are varying perspectives around technology viability, timing of availability, cost and risk across a myriad of technologies, such as advanced nuclear, long-duration energy storage, hydrogen fuel, and CCS. Technology advancements are critical as coal retires and diverse, increasingly clean, and operationally compatible technologies are needed to maintain or improve system reliability. That is why the Company closely follows and participates in technology monitoring and study. For example, the Company was recently awarded a CCS front-end engineering design study at the Edwardsport IGCC plant by the DOE Office of Clean Energy Demonstrations. For the IRP, the Company must make assumptions based on the best available information and through industry and stakeholder networks monitor those assumptions during execution – and adjust in future planning cycles with more and better information. Additional information on resource planning assumptions is in Chapter 2 and in Appendix C (Quantitative Analysis).

Considerations Impacting Affordability for Replacement Generation

As discussed above, recent policies have provided incentives for generation investments in renewable energy, nuclear, CCS, hydrogen and energy storage. These policies are included in the IRP modeling, providing cost reductions. However, at the same time, the macroeconomic environment is continuing to experience inflation and a period of general uncertainty, increasing financing costs and labor and material costs through supply chains supporting all resources – including into primary materials such as rare earths, copper, and steel production. As a result, the Company has seen increasing costs across all technology types since its last IRP submittal, as detailed in Appendix F. Moreover, lead times to implement infrastructure are extending to account for longer lead times for certain parts and equipment, generator interconnection, and siting and permitting activities, increasingly recognized by state and federal government leaders as a challenge to advancing the energy transition. These issues are borne out in the request for proposal results and the Company’s own internal generation planning, where MISO interconnection queue delays, equipment vendor lead times and expected natural gas pipeline construction lead times have lengthened the time to bring new generation resources online and limited the number of new resources a utility can reasonably expect to develop and construct in any given year.

For new generation siting, the Company is prioritizing customer affordability through repurposing existing generation sites. These locations provide for favorable access to water, streamlined transmission interconnection, and a capable workforce which allow Duke Energy Indiana to continue to invest in these local communities.

Consideration of affordability calls for a moderate and intentional transition to mitigate the impact on customers. The pace of moderation will, however, be heavily influenced by the environmental policy realities discussed above. Inflationary pressures, siting and permitting lead times, in combination with supply chain and labor constraints, put emphasis on proactively monitoring risks and signposts and ensuring a continued “check and adjust” feedback loop across resource planning and execution.

Customer Trends

Customers have an increasing awareness and desire for energy stewardship. The Company considers the source and impact of energy choices on the environment and communities, in addition to ensuring an affordable and reliable energy supply. Customers increasingly want options to participate in the energy transition through access to renewables and the ability to influence and optimize system needs through energy efficiency, demand-side tools, and customer program participation. Indeed, the Company has seen a clear trend of economic development interests and existing large industrial and commercial customers demanding renewables and emissions reductions to meet their own clean energy goals.

Related to siting and execution of infrastructure projects, stakeholders, customers, and communities are engaging in environmental justice and impacted community activities. They are expressing increasing interest in not just personal energy stewardship on the consumption side, but broader community-based energy stewardship related to local environmental, economic, and social impacts of the energy transition.

There is a wide range of perspectives on the potential outcomes, system impacts, adoption rates, and cost impacts of consumer electrification patterns, energy efficiency, demand-side tools, and customer programs. Similar to technology advancements, the IRP must make assumptions on relative impact to load that these demand-side changes and customer-based programs may have based on the best available information and through industry and stakeholder networks. The Company continues to advance its commitment to providing customers with clean energy options and demand-side tools to influence load and “shrink the challenge” of the energy transition as described in Appendix H (Demand-Side Resources & Customer Programs). The Company will monitor the quantifiable results of these trends, programs, and adoptions rates and make necessary adjustments in future planning cycles. Additional information on resource planning assumptions is provided in Chapter 3, and the appendices.

Key Elements of a Balanced & Orderly Energy Transition

Several key elements to ensuring the energy transition advances in a balanced, prudent, and reasonable manner in the face of a dynamic planning environment are described in Table 1-2 below. In an integrated system, an “all of the above approach” and balanced portfolio approach are necessary as solutions work in concert to meet the planning objectives and provide important risk hedging through diversity of supply.

Table 1-2: Key Elements of a Balanced and Orderly Energy Future

	Element	Benefit
	Generation retirements only after timely commissioning of equally reliable resources	During transition, ensuring the replacement of retiring older units with new units coming online (and where appropriate adding additional capacity) and modernizing the fleet will ensure the ability to provide reliability in all hours.
	Dispatchable resources throughout planning period Dispatchable resources throughout planning period (Cont.)	To ensure reliability, dispatchable resources are needed in the near, intermediate, and long terms. Near and intermediate timeframes will require efficient and flexible natural gas generation to replace aging coal facilities, while emerging, dispatchable technologies mature. In the long term, advanced nuclear may provide the best promise for carbon-free, reliable generation, along with renewables and energy storage.
	Strategic grid planning and investment	Plans to modernize the grid and MISO’s long range transmission planning process are critical to ensure that transmission investment will not be a barrier to needed generation investment and the clean energy transition.
	Diverse set of resources to ensure reliability in uncertain future	Given uncertainty of political, regulatory, and technology environments, diversity of resources and optionality are keys to success.
	Fuel assurance	Assurance of fuel availability for fossil resources during the transition is a key element to a reliable portfolio. This includes natural gas pipeline build-out, firm transportation and dual fuel options, and on-site coal availability from a diverse set of suppliers.
	Competitive procurement process	The Company will continue competitive requests for proposal (“RFP”) and other processes to ensure short-term actions are cost-effective for customers.
	Constructive regulatory mechanisms for investment	Constructive regulatory mechanisms such as construction work in progress and timely cost recovery, expedited regulatory proceedings and processes, reasonable assurance of cost recovery for prudently incurred planning costs, and reasonable return and recovery of stranded costs are critical to a successful transition.

72	Advancement of energy efficiency, demand response, and customer programs	Continued commitment to energy efficiency, demand response and customer programs, and using grid edge technologies will help ensure customer acceptance of transition and lower overall costs.

2024 Integrated Resource Plan Improvements

The IRP process continues to evolve, and this IRP cycle is no exception. In fact, between the 2021 and 2024 IRP, significant policy changes required updating IRP analysis multiple times and there are a number of new issues included in the 2024 IRP. Duke Energy Indiana strives for continuous improvement in its planning processes and has thoughtfully considered and incorporated stakeholder feedback throughout the 2024 IRP process.

Table 1-3 below lists new 2024 IRP issues and improvements and indicates where they are addressed in the IRP document.

Table 1-3: 2024 IRP New Issues and Improvements

2024 New Issues/ Improvements	Location in IRP Document
• Incorporation of Indiana's Five Pillars of energy policy – Reliability, Resiliency, Stability, Environmental Sustainability and Affordability	*Chapter 2 (Methodology)*
• Enhanced Reliability Evaluation (Resource adequacy of portfolios) • Stochastic analysis to measure robustness of portfolios	*Chapter 2 (Methodology);* *Chapter 4 (Candidate Resource Portfolios);* *Appendix C (Quantitative Analysis);* *Appendix E (Reliability & Resource Adequacy);*
• EPA CAA Section 111 Rule, EPA Greenhouse Gas Rule impacts	*Chapter 2 (Methodology);* *Chapter 3 (Key Assumptions)*
• IRA assumptions regarding clean energy tax incentives • Significant economic development activity, including additional high load sensitivities	*Chapter 2 (Methodology);* *Chapter 3 (Key Assumptions);* *Appendix D (Load Forecast)*
• MISO seasonal construct leading to periods of winter planning versus historically summer planning	*Chapter 2 (Methodology);* *Chapter 3 (Key Assumptions)*

• Adjusted unforced capacity to reflect recent MISO capacity accreditation changes, including SAC and proposed DLOL methodologies	*Chapter 2 (Methodology); Chapter 3 (Key Assumptions); Appendix E (Reliability & Resource Adequacy)*
• Updated Demand-Side Management Market Potential Study • Additional detail on energy efficiency and demand response resources	*Appendix H (Demand-Side Resources & Customer Programs); Appendix C (Quantitative Analysis)*
• More rigorous approach to alternate load forecast sensitivities and additional detail on load forecasting methodology	*Appendix D (Load Forecast)*
• Advanced analytical framework, using generation strategies to inform EPA CAA Section 111 Rule compliance pathways and worldviews to evaluate portfolios in a diverse range of futures	*Chapter 2 (Methodology)*
• Enhanced stakeholder engagement process, incorporated new practices, and enriched meeting content, prioritizing broad, transparent, and inclusive stakeholder participation • Improved Technical Stakeholder communication through regular meetings and data provision throughout IRP cycle	*Chapter 2 (Methodology); Appendix A (Stakeholder Engagement)*
• Simultaneous RFP process to inform key IRP assumptions	*Appendix G (Competitive Procurement Process)*
• Earlier discussion and determination of scorecard decision criteria to include the Five Pillars of energy policy.	*Chapter 2 (Methodology); Appendix A (Stakeholder Engagement)*
• Study of CCS Edwardsport IGCC Plant as potential compliance option under EPA CAA Section 111 Rule	*Chapter 2 (Methodology); Chapter 3 (Key Assumptions)*
• Increased use of publicly available data and blended proprietary cost curves to allow for more detailed content to be shared publicly in stakeholder meetings and within the document • Improved processes for developing resource technology costs	*Chapter 2 (Methodology); Chapter 3 (Key Assumptions); Appendix F (Supply-Side Resources)*

Chapter 2: Methodology

Highlights

- An Integrated Resource Plan acts as a strategic compass, shaped by evolving policies that significantly impact long-term planning. As uncertainty increases further into the future, Duke Energy Indiana is committed to maintaining a robust, continuous planning process.
- The balanced, stakeholder-informed scorecard evaluates the extent to which diverse resource plans satisfy the Company's planning objectives, which include the "Five Pillars" of Indiana energy policy while also accounting for risk and uncertainty.
- The Company's analytical framework enables thorough evaluation of the risks, uncertainties, and potential trade-offs among resource decisions. The process ensures Duke Energy Indiana can navigate the changing energy landscape with flexibility while taking prudent steps in the near term to benefit customers throughout the planning horizon.
- The methodology employed in the 2024 Integrated Resource Plan process reflects Duke Energy Indiana's ongoing dedication to refining and improving its planning methods and accounting for dynamic economic, regulatory, and technological changes.

Resource planning in a changing energy landscape is a complex endeavor that must balance dynamic planning objectives while addressing inherent uncertainties and risks. For Duke Energy Indiana (the "Company"), this involves a robust, yearlong process of engaging with stakeholders, modeling and evaluating a range of strategies and scenarios to develop a resource plan that ensures reliable, affordable, and increasingly clean energy for customers.

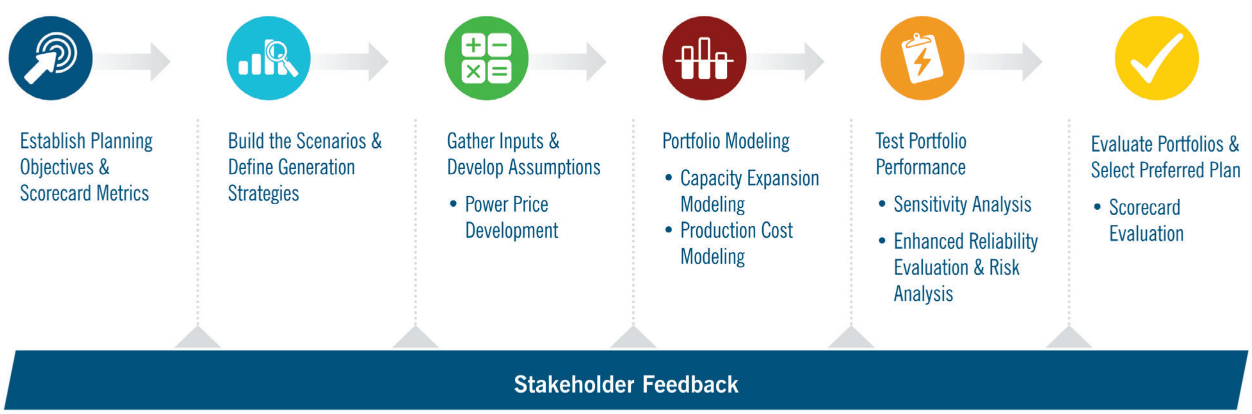
The Company's methodology for the 2024 Integrated Resource Plan ("IRP") incorporates stakeholder feedback and introduces new planning elements and approaches in response to an evolving landscape, where unprecedented growth in energy demand and increasing uncertainty from environmental regulations present new challenges across the planning horizon.

This Chapter outlines Duke Energy Indiana's resource planning objectives, the analytical framework utilized to develop the IRP, and the primary steps involved in the modeling process. This Chapter also describes the scorecard metrics used to assess resource plans and inform selection of the preferred resource plan ("Preferred Portfolio"). Portfolio modeling results, the final scorecard evaluation, and additional technical information are provided in subsequent chapters, as well as in other appendices referenced herein.

Introduction to the Resource Planning Process

Duke Energy Indiana's 2024 IRP was developed according to the detailed planning process outlined in Figure 2-1 below. At its core, the IRP process is structured to develop and analyze a diverse set of portfolios and resource options over the 20-year planning horizon from which to select a preferred long-term resource mix. The Preferred Portfolio must meet customers' energy adequacy and reliability needs with an increasingly clean resource mix, while maintaining affordability for customers and prudently managing risk and uncertainty.

Figure 2-1: 2024 Integrated Resource Planning Process



The necessary first step in the planning approach is to establish the Company's resource planning objectives and the measurements with which to evaluate future resource portfolios with respect to the planning objectives. The planning objectives serve as guiding principles and a foundation from which a balanced long-term resource mix is built. Next, the Company determines which key planning questions and uncertainties will impact the future. The analytical framework, including scenarios and generation strategies, is structured around those key questions. The Company builds scenarios, or "worldviews," addressing market and regulatory uncertainties. Then, the Company establishes generation strategies defining potential pathways for Duke Energy Indiana resource decisions considering key impactful environmental policies and constraints. Critical inputs are gathered, and key assumptions are developed for the Company to begin the process of modeling portfolios and testing portfolios' performance under varying conditions. Finally, performance of the candidate portfolios is summarized on a scorecard that includes a set of measures developed in concert with stakeholders to gauge portfolios' ability to balance the planning objectives. Based on this evaluation and the supporting information provided by the full scope of resource planning analytics, the Company identifies the Preferred Portfolio. Engagement with stakeholders is a critical component of the overall IRP process and is described in more detail below, as well as in Appendix A (Stakeholder Engagement).

Stakeholder Engagement

Stakeholder engagement is a foundational element of the Duke Energy Indiana Integrated Resource Plan process. The Company considers the needs and concerns of a diverse audience, including customers, regulators, environmental organizations, social advocates, community agencies, elected officials, employees and many others.

The 2024 engagement process consisted of five technical and five public meetings over the course of nine months, covering a wide range of technical matters as shown in Figure 2-2 below. The IRP was informed not only by these sessions, but also by other subject matter-specific engagement efforts across Duke Energy Indiana.

Figure 2-2: Stakeholder Engagement Timeline and Key Topics

As the focus of IRP stakeholder engagement is to obtain feedback on the Company's modeling assumptions and inputs, meetings were structured to ensure meaningful discussion of a significant number of complex technical topics. To enhance the focus on these more technical aspects of the Integrated Resource Plan development process, stakeholders from varying backgrounds participated in topical meetings as technical representatives to ensure deeper and more informative discussion. Throughout the IRP process, stakeholders were also invited to meet outside of the formal sessions, and as a result, the Company met with several stakeholders on an individual basis to discuss specific areas of interest.

The robust stakeholder engagement process for the 2024 IRP is detailed in Appendix A. Improvements to the process are also discussed later in this Chapter.

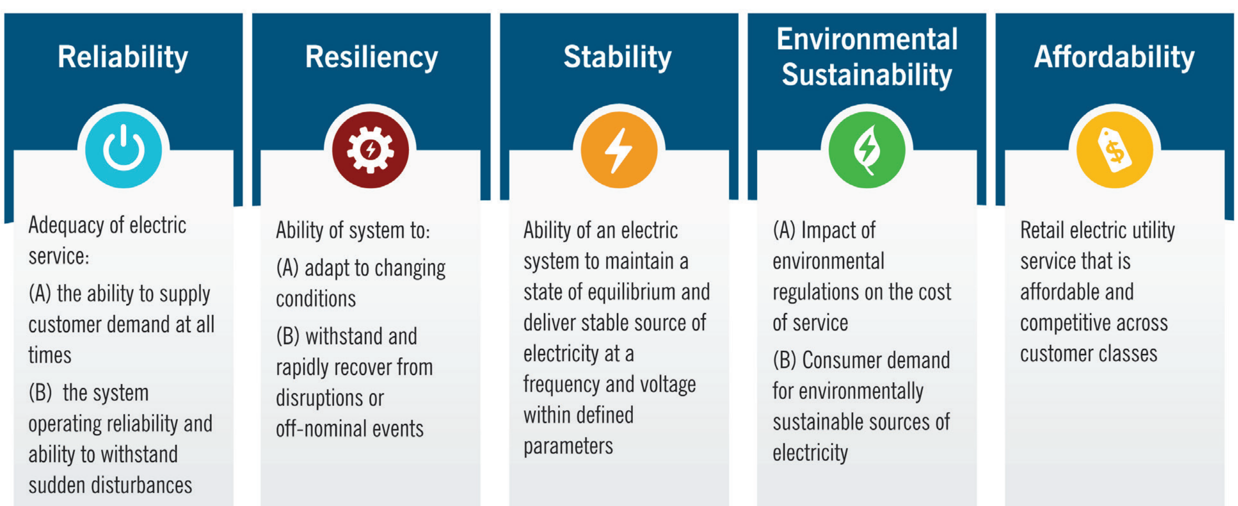
Resource Planning Objectives

In today's evolving energy landscape described in Chapter 1 (Planning for the Future Energy Landscape), Duke Energy Indiana establishes planning objectives to serve as guiding principles of long-term resource planning and considers the interdependencies and risks of resource decisions as part of a measured energy transition.

The Preferred Portfolio must comply with applicable planning, environmental, and other laws and regulations that govern resource planning inputs and outputs, while ensuring reliable electricity service for customers. The Company's planning objectives must also balance risks and timing of a measured energy transition. This is done by ensuring resource diversity and flexibility to mitigate fuel and technology risks, applying least-cost planning principles and considering affordability for customers, and accounting for risk and uncertainty in the face of changing conditions, such as evolving policies and technology advancements.

Duke Energy Indiana's resource planning objectives are based on the "Five Pillars of Electric Utility Service" (commonly referenced as the "Five Pillars") introduced by Indiana's 21st Century Energy Policy Development Task Force – Reliability, Affordability, Resiliency, Stability, and Environmental Sustainability.[1] These pillars were further codified in Indiana Code 8-1-2-0.6, which affirmed "the continuing policy of the State that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider [the Five Pillars]".[2] Figure 2-3 below summarizes the Five Pillars as defined in Indiana Code 8-1-2-0.6.

Figure 2-3: The Five Pillars of Indiana Energy Policy



[1] Indiana General Assembly, 21st Century Energy Policy Development Task Force Final Report, October 19, 2022.

[2] Indiana Code 8-1-2-0.6 (2023).

In addition to the Five Pillars, the Company's planning objectives include the consideration of risk and uncertainty as shown in Figure 2-4 below. Each of the Company's resource planning objectives is described in more detail below.

Figure 2-4: Duke Energy Indiana's Resource Planning Objectives

Reliability

System reliability and adequacy of resources to serve customer demand are primary obligations of the Company, along with meeting specific North American Reliability Corporation ("NERC") reliability requirements in system planning and operations. Customers expect Duke Energy Indiana to meet their energy needs reliably at all times of day and during all seasons of the year. The Company must plan for the aggregate needs of the system now and into the future for both normal and extreme weather conditions. Across the country, electric system reliability is increasingly challenged by summer heat waves, winter storms, and other extreme weather events. The increasing frequency and intensity of extreme weather events reinforces the central importance of system reliability to customers and businesses.

While the Midcontinent Independent System Operator ("MISO") is charged with maintaining the reliability of its regions, Duke Energy Indiana must ensure that it plans for a future resource portfolio that cost-effectively supplies the capacity and energy needed to meet its obligation to its customers. In recent years, MISO has shown a general need for additional generating capacity in the Indiana zone and potential related reliability concerns in future years. MISO has begun to implement and plan future changes to the way in which it models, values, and procures resources to ensure reliability and continues to study the impacts of an increasing penetration of intermittent generation in the market. The Company expects MISO's capacity accreditation construct to undergo significant further change in the coming years. Duke Energy Indiana closely monitors potential policy changes from MISO that could impact the capacity needs and resource requirements to maintain system reliability.

Given increasing uncertainty, a primary objective of long-term resource planning must be to maintain adequate reserves to serve customers through peak demand periods and meet capacity needs essential for economic development and growth in Indiana. In addition, there must be adequate system flexibility to serve customer demand that varies by year, season, day, and minute. Chapter 3 (Key Assumptions) defines the long-term planning reserve margin needed to meet resource adequacy at seasonal demand peaks and the accreditation constructs used to determine how much capacity a given resource can be relied upon for meeting the planning reserve margin requirement. Appendix E (Reliability & Resource Adequacy) describes the enhanced reliability modeling used to further test system needs by taking into consideration a given portfolio's ability to meet varying seasonal demand patterns. Appendix E also provides further context and considerations on maintaining reliability during the energy transition, as the resource mix changes for both Duke Energy Indiana and the broader MISO market.

Customer Affordability

Like reliability, cost-competitive rates and customer affordability are important for the vitality and continued growth of Indiana's economy. Maintaining customer affordability is critical to a sustainable transition of the electric power system. Affordability ensures that all customer segments can access reliable and efficient energy services without undue financial strain. This balance is vital for fostering public support for infrastructure required in the near term of the Preferred Portfolio. By prioritizing affordability, IRPs incorporate cost-effective resource options and innovative technologies, which contribute to long-term economic stability and the equitable distribution of energy benefits. Further, the IRP must balance key trade-offs among the needs for reliability and environmental sustainability with the fundamental importance of competitive and affordable rates across all customer classes.

Environmental Sustainability

Duke Energy Indiana must plan to balance risks associated with load growth while planning for an increasingly clean resource mix. Retiring, converting, and replacing (including repurposing sites where feasible) over 3,800 megawatts ("MW") of aging coal generation at an appropriate pace mitigates reliability and cost risks while significantly contributing to emissions reductions. Duke Energy has held a corporate commitment to clean energy for well over a decade, aligning with, and in response to, the clean energy goals of many of the customers currently served by Duke Energy Indiana, as well as the clean energy goals of industries and businesses looking to expand into the state.

Historical and evolving regulatory requirements and policy drivers, including the Environmental Protection Agency's Clean Air Act Section 111 May 2024 Final Rule ("EPA CAA Section 111 Rule"), underscore the need to plan for an increasingly clean resource mix. This objective must be balanced with the need to maintain reliability and affordability for customers. Timely commissioning of equally reliable replacement resources and the certainty of regulatory decisions to enable those replacements are essential to managing operational risk and ensuring a sustainable transition – one that does not compromise reliability, stability, resiliency, or affordability of electric service for all customer classes.

Resiliency

Resiliency is the ability of a system or its components to adapt to changing conditions, withstand disruptions, and rapidly recover from off-nominal events. The Company considers resilience in all decisions related to the generation resource mix and supporting electric infrastructure, acknowledging the inevitability and increasing risk of extreme events, both natural and man-made. Along with ensuring the availability of necessary resources to respond to such events, the Company continues to make meaningful investment in Indiana's electric infrastructure to maintain and improve the system's resiliency.

A resilient system must also respond to real-time fluctuations in customer loads and renewable output. In resource planning, resource diversity provides value for risk mitigation and resilience, as diversity of resources in a system means the system has a larger set of characteristics that adapt differently under different circumstances. Planning a resilient system means recognizing and accounting for the attributes and limitations of any one resource or fuel type. Thus, a diverse and balanced portfolio of energy resources allows the Company the ability to hedge risks and costs and take advantage of complementary technologies to optimize the system across economics, reliability, and environmental attributes. A sustainable energy transition will require a diverse array of tools in the toolbox – an "all of the above" approach. Having more tools in the toolbox to operate the system increases operational flexibility but also adds complexity for system operators that will require a glide path of operational experience as new technologies are integrated into the system at scale. Ultimately, a balanced and diverse resource mix prudently manages technology and fuel risks across the portfolio and provides for operational flexibility in all conditions.

Stability

Stable, robust power systems are strong networks, able to ride through different disturbances and maintain equilibrium. Stability of electric supply is essential to Indiana's industrial manufacturers and economy and is a basic requirement in Duke Energy Indiana's transmission planning. The Company adheres to all applicable industry standards and to its own detailed planning criteria. The stability of the Duke Energy Indiana system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC and ReliabilityFirst Corporation Reliability Standards. Generating units, at a minimum, must maintain stability and deliver electricity at a frequency and voltage consistent with industry standards under various contingency situations. These standards and the Company's transmission planning process and planning criteria are discussed further in Appendix I (Transmission Planning).

Proliferation of inverter-based resources coupled with continued retirement of dispatchable coal resources has introduced emergent grid reliability challenges in recent years. Given varying adoption rates, different parts of the country, and consequently the bulk grid, are experiencing these challenges at a different pace and severity. As noted by MISO's Resource Adequacy Subcommittee, "high levels of renewables result in a declining peak contribution and can create system instability."[3] In addition to adherence to all standards to ensure system stability, Duke Energy Indiana continues to monitor the changing resource mix in MISO and the implications of new technologies to address potential stability issues emerging from the energy transition. The Company is currently aware of and monitoring

[3] Midcontinent Independent System Operator, Inc, MISO Dashboard, July 23, 2024, available at https://www.misoenergy.org/engage/MISO-Dashboard/forward-capacity-accreditation-for-renewable-resources/.

technologies that may offer mitigation of potential stability issues. Specifically, these technologies include grid-forming inverter technology, additional fast-start resources such as battery storage, super capacitors or natural gas combustion turbines, and additional synchronous condensers.

Accounting for Risk & Uncertainty

Long-term resource planning requires addressing risks and uncertainties, particularly as future changes in economic conditions, policies, and technologies are challenging to predict. While planning and forecasting cannot provide perfect foresight, plans must still consider realities experienced “on the ground” through execution or account for reasonably foreseeable conditions. Many examples have already been highlighted in Chapter 1 such as environmental regulations making coal generation increasingly uneconomic and industries that are seeking to locate and expand in Indiana that are prioritizing access to increasingly clean energy as an important criterion of their siting process.

Other factors impacting generation project lead times and costs include supply chain and workforce constraints, requirements and challenges for siting and permitting, and the consideration of significant infrastructure dependencies such as transmission or fuel supply needs. This is a broad area that must be balanced with other planning objectives to ensure plan executability and account for realistic conditions in the planning environment.

Scorecard Evaluation Metrics

Duke Energy Indiana developed a comprehensive set of stakeholder-informed scorecard metrics to evaluate the candidate portfolios with respect to the resource planning objectives and guide selection of the Preferred Portfolio. The scorecard metrics are categorized by planning objective and provide a snapshot of a portfolio’s relative performance on each planning objective. As discussed earlier in this Chapter, the planning objectives include the Five Pillars (Reliability, Affordability, Resiliency, Stability, and Environmental Sustainability) and the consideration of risk and uncertainty. The scorecard metrics for each planning objective are summarized below. The scorecard results and evaluation across candidate portfolios are provided in Chapter 4 (Candidate Resource Portfolios).

In addition to the scorecard metrics and substantial quantitative analysis informing selection of the Preferred Portfolio, the Company must equally consider qualitative factors influenced by the continuously evolving energy landscape to ensure Duke Energy Indiana’s portfolio and pathway remain flexible in the face of significant uncertainty.

Environmental Sustainability Metrics

Metric	Description	Purpose
CO_2 Emissions Reduction	Percent CO_2 emissions reduction at specified years (2035, 2044) relative to Planning Year 1 (2025), including estimated CO_2 emissions associated with market purchases	Allows comparison of pace of emissions reduction
Cumulative CO_2 Reduction	Cumulative volume of CO_2 reduction over the planning period, reflected as million tons reduced through 2044 relative to Planning Year 1 (2025) including estimated CO_2 emissions associated with market purchases	Allows comparison of cumulative emissions reduction
CO_2 Intensity of Duke Energy Indiana	CO_2 emissions from Duke Energy Indiana resources per megawatt-hour (MWh) of energy generated by those resources	Assesses environmental sustainability of Duke Energy Indiana's resource portfolio

Affordability Metrics

Metric	Description	Purpose
Present Value Revenue Requirement ("PVRR")	Total forecasted revenue requirement associated with resource plan investments over the planning period, discounted to present	Provides estimate of total portfolio cost over analysis period in present value terms
Customer Bill Impact ("CAGR")	Average annual rate impact to customers over 5-year and 10-year time periods expressed as projected compound annual growth rate in customer bill of typical residential household using 1,000 kWh/month associated with resource plan investments, inclusive of existing unit ongoing costs	Provides snapshot of portfolio cost impact to customers at points in time

Reliability Metrics

Metric	Description	Purpose
Fast Start Capability	Fast-start capable resource capacity MW as a percent of peak load in 2035. Fast-start capable resources include combustion turbine (“CT”) and battery.	Indicates ability of the portfolio to compensate for unpredictable imbalances between load and generation
Spinning Reserve Capability	Spinning reserve capable resource capacity MW as a percent of peak load in 2035. Spinning reserve capable resources include steam, combined cycle (“CC”), CT, combined heat and power, and hydro.	Indicates ability of the portfolio to provide energy ‘on-demand’ during high-risk hours and meet demand if there is a sudden shortfall in generation

Resiliency Metrics

Metric	Description	Purpose
Resource Diversity	An empirically derived diversity baseline of the system’s capacity resources by technology type, as measured by the Herfindahl-Hirschman Index– the sum of squares of technology share in the portfolio on a firm capacity basis in 2035.	Measures diversity of capacity resources as an indicator of resilience through risk diversification
Simulated EUE in 95th Percentile Cold Weather as Islanded System	Stochastically simulated expected unserved energy (“EUE”) as a percent of load during coldest weather (95th percentile or colder) observed in Indiana over the past 44 years with market purchases turned off.	Tests portfolio performance in coldest hours as indicator of relative reliability and resilience across portfolios

Risk & Uncertainty Metrics

Cost Risk

Metric	Description	Purpose
Cost Variability Across Scenarios	The minimum and maximum PVRRs of the portfolio across the scenarios evaluated	Indicates risk of cost variance and high-cost outcomes across different potential futures
IRA Exposure	Portion of cumulative MW additions assumed to receive IRA credits relative to total resource additions through 2030 and 2035	Indicates both opportunity and risk of the IRA tax credits

Market Exposure

Metric	Description	Purpose
Fuel Market Exposure	Energy generated by resources with exposure to coal and gas market prices as percent of total fleet generation, averaged annually over the planning period	Indicates cost risk associated with fuel price volatility
Maximum Energy Market Exposure	Absolute value of maximum single year annual energy purchases net of sales as percent of load	Indicates cost risk associated with each portfolio's market exposure

Execution Risk

Metric	Description	Purpose
Cumulative Resource Additions in MW and as % of Current System	Cumulative MW additions of all capacity resource technology types, including DSM, through 2030 and 2035, expressed in MW and as percent of total MW capacity serving customers today	Indicates scale and pace of infrastructure siting, procurement, permitting, construction and interconnection required for successful plan execution

Stability Metrics

During the stakeholder engagement process, the Company reviewed several potential measurements of stability for inclusion on the scorecard. For example, the Company considered measuring the rate of change of inertial megawatts as an indication of risk to stability arising from operational complexities as the fleet is transitioned. The Company also considered measuring the penetration of inverter-based resources (“IBRs”) in a future resource mix as a means of indicating risk to stability and potential voltage support issues that could arise with a high penetration of IBRs.

Ultimately, stakeholders recommended a narrative approach to this planning objective. In lieu of quantitative metric(s) for stability, the Company has described potential issues and future challenges that may arise while dispatchable resources are retired and intermittent generation becomes a greater share of generating capacity in Duke Energy Indiana and the broader MISO territory. These challenges are discussed in Chapter 1 and Appendix E. Appendix I describes the Company’s transmission planning processes, detailed planning criteria, and analyses used to ensure continued system stability.

Analytical Framework

The IRP analytical framework allows for robust evaluation of the risks, uncertainties, and potential trade-offs relative to the planning objectives described above. This section describes the framework, including the scenarios, generation strategies, and additional analysis concepts used to develop and evaluate the 2024 IRP.

Scenarios (“Worldviews”)

Scenario development involves outlining potential futures and how various external trends could impact key variables within a resource plan. Alternate scenarios are designed to test a portfolio's performance across a diverse range of future world landscapes, enabling planners to evaluate the robustness and flexibility of resource plans in the face of uncertainty. In this process, numerous assumptions are modified simultaneously to reflect a substantially different overall view of the future. Scenarios serve as stressors to evaluate how different future resource plans perform under varied future conditions relative to each other with respect to the resource planning objectives described earlier in this Chapter.

The first scenario developed in planning is the Reference Case, or “Reference Worldview,” which is the Company’s "most likely future scenario."[4] This scenario reflects the best estimates of future electric system requirements, fuel price projections, and an objective analysis of the necessary resources over the planning horizon to meet customer needs safely, reliably and economically. It includes existing laws and policies and serves as a baseline against which other scenarios are compared.

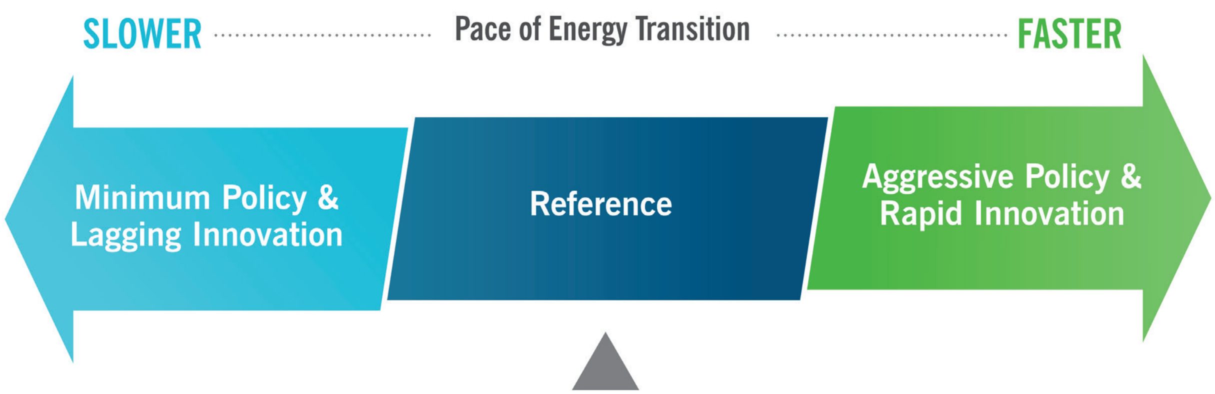
Once a Reference Case is established, alternate scenarios are developed. The goal of this step is to create scenarios that reflect sufficiently different forecasts from the Reference Case to encompass a range of plausible future outcomes, where the fundamental drivers of those alternate futures conceivably impact several modeling inputs. To achieve this broad scope, the Company analyzed various perspectives on key external market drivers and other impactful planning assumptions that are influenced by external factors. Scenarios do not include assumptions about Company actions or

[4] 170 Indiana Administrative Code 4-7-4.

resource portfolio decisions so that potential Duke Energy Indiana plans and decisions can be evaluated within and across scenarios.

In assessing external trends, the Company identified **policy** and **innovation** as pivotal drivers potentially leading to dramatically different future outcomes, impacting many key planning assumptions, and setting the **pace of the energy transition**. Figure 2-5 below illustrates the worldviews along a scale of the pace of the energy transition.

Figure 2-5: 2024 Integrated Resource Plan Scenarios ("Worldviews")



On one end of the spectrum illustrated in Figure 2-5, there is minimal climate policy intervention and lagging technology innovation, leading to a slower pace of energy transition. This worldview is the Minimum Policy & Lagging Innovation ("Minimum") scenario. On the opposite end, there is aggressive climate policy intervention and rapid technology innovation. This worldview is the Aggressive Policy & Rapid Innovation ("Aggressive") scenario.

These scenarios are not predictions of what the future will be; they are instead descriptions of what the future plausibly *could* be. They do not reflect the Company's policy goals. Rather, they are intentionally varied futures designed to push the boundaries of what might be considered plausible future outcomes and are modeled with a unique set of input assumptions corresponding to the external influences defining each scenario.

The planning input assumptions impacted by *more or less aggressive* climate policy and *more or less rapid* technological innovation include:

- Regulation of coal and natural gas electric generating units
- Incentives for clean energy investment and production
- Implementation of tax on carbon emissions
- Fuel prices (coal, natural gas)
- Resource availability (pace at which new resources can be interconnected)

- Capital costs of renewables and storage resources
- Customer adoption of distributed energy resources such as behind-the-meter solar
- Commercial availability of emerging resource technologies

A qualitative description of the assumptions defining the alternate scenarios is included below and summarized below in Figure 2-6. Quantitative inputs for all scenarios are provided in Chapter 3.

Aggressive Policy & Rapid Innovation

In the Aggressive Policy & Rapid Innovation scenario, power sector emissions are regulated through a mix of incentives, taxes, and environmental restrictions, driving the market to innovate more rapidly and deliver the energy transition at a faster pace.

- Existing coal and new natural gas generation facilities are regulated by EPA CAA Section 111 Rule. In addition, *existing* natural gas combustion turbines are regulated by stringent greenhouse gas restrictions.
- Aggressive regulation limits the supply of coal and natural gas, driving higher fuel prices.
- Inflation Reduction Act ("IRA") incentives are extended, and provisions enable increased capture of bonus incentives for domestic content.
- Resource availability remains consistent with the Reference Case in the near term (through 2028), but favorable transmission and queue reform is enacted to enable higher interconnection of renewable resources in the longer-term planning horizon (beginning 2029).
- A carbon tax is legislated and implemented by 2030.
- Extension of favorable government incentives for clean energy reduces overall cost of renewables and storage. These incentives encourage higher adoption of distributed energy resources by customers.
- Incentives for emerging technology research and development will accelerate the commercialization and availability of new resource options, including long-duration energy storage and hydrogen ("H_2") fuel.

Minimum Policy & Lagging Innovation

In the Minimum Policy & Lagging Innovation scenario, federal regulations and clean energy incentives are rolled back, leading to stalled innovation in the sector and an overall slower pace of energy transition.

- EPA Clean Air Act Sections 111(b) and (d) in the May 2024 Final Rule are repealed prior to implementation.
- Less government regulation drives price competition among competing fuels, leading to lower prices for coal and natural gas.

- IRA is repealed by 2025.
- Resource availability remains consistent with the Reference Case throughout the planning period.
- Carbon tax legislation is not passed.
- Reduced government incentives for renewables and storage increases overall cost which is offset by tempered demand. Similarly, reduced incentives available lead to lower adoption of distributed energy resources by customers.
- Lack of incentives for emerging technology research and development leads to delayed commercialization and insufficient supply chain for new resources such as advanced nuclear.

Figure 2-6: Summary of Assumptions by Scenario

	Minimum Policy & Lagging Innovation	Reference	Aggressive Policy & Rapid Innovation
CAA 111	No	Yes	Yes + Existing Gas
Coal Price	Low	Base	High
Gas Price	Low	Base	High
IRA	No	Yes	Yes
Resource Availability (interconnection timing)	Base	Base	High Renewable Availability in Long-Term
CO_2 Tax	No	No	Yes
Renewables & Storage Cost	Base	Base	Low
Distributed Resources	Low	Base	High
Emerging Technology	Advanced Nuclear not available	Base	Long Duration Energy Storage & H2 Available

High | Base | Low | Yes | No

Generation Strategies

To guide specification of candidate resource portfolios for quantitative analysis under the worldviews described above, the Company developed generation strategies, which outline potential future options for the existing fleet of coal-fired units. The generation strategies were designed around the compliance pathways mandated by the EPA CAA Section 111 Rule, which directly limits the flexibility to optimize resource modeling for existing coal units. The introduction of the EPA CAA Section 111 Rule prescribes specific compliance options for existing coal generation, thus, modeling a Reference Case, which necessarily considers current legislation, is constrained to align with regulatory-compliant pathways. This necessitates a shift in how the Company approaches portfolio development, as increasingly deterministic regulation constrains the set of options available to balance other planning objectives.

Duke Energy Indiana operates seven coal-fired steam units and the Edwardsport Integrated Gasification Combined Cycle ("IGCC") facility, each of which is subject to the requirements set forth in EPA CAA Sections 111(b) and 111(d), which are discussed in more detail in Chapter 3. At a high-level, the options include: (1) retirement by January 1, 2032, (2) conversion to 100% natural gas by January 1, 2032; (3) natural gas co-firing by January 1, 2030, and (4) implementation of nascent carbon capture and sequestration ("CCS") technology by January 1, 2032. The Company does not expect CCS to be a viable option by 2032 at any of its coal units except potentially the Edwardsport IGCC, where a front-end engineering and design ("FEED") study is already underway. Evaluating every possible combination of retirement, conversion to natural gas, or co-firing at the seven steam units would result in 2,187 distinct resource portfolios under the Reference Case alone.

To reduce the set of potential candidate portfolios, the Company began its analysis by creating two "bookend" generation strategies: one where all coal units are converted to natural gas or natural gas and coal co-firing by 2030, and the other where all coal units are retired by 2032. These two bounds, referred to as "Convert/Co-Fire Coal" and "Retire Coal," provided valuable insights into the resource needs associated with retaining existing steam units versus retiring and replacing aging generators. From there, the Company considered several reasonable combinations of the different compliance options for each coal unit in the fleet. To narrow in on the portfolios/combination of individual unit decisions to evaluate in the IRP, internal subject matter experts from plant operations, fuels procurement, environmental compliance and major projects collaborated to assess the operational considerations specific to each unit. This allowed for prioritization of the most viable compliance pathways for each unit, ensuring that the selected generation strategies were both practical and executable within the given real-world constraints.

Using the insights from the bookends alongside the operational considerations, the Company developed additional generation strategies, referred to as "blends." These blends incorporate combinations of retirement, natural gas conversion, and co-firing based on factors such as the unit's age, efficiency, and compliance-related infrastructure costs of each unit, as well as the current and future availability of natural gas to the site. In addition to the bookend and blend strategies developed, the Company collaborated with a stakeholder group to include a stakeholder-inspired generation strategy titled "Exit Coal Earlier (Stakeholder)."

This approach allowed the Company to create six distinct generation strategies, each of which was evaluated under the three scenarios – Reference, Aggressive, and Minimum – resulting in 18 portfolios. While the generation strategies prescribe decisions for existing coal units, the model optimizes selection of new resource additions. The composition of each generation strategy is outlined in Figure 2-7 below and described in further detail in Chapter 4.

Figure 2-7: Summary of 2024 IRP Generation Strategies

<table>
<tr><th>UNIT</th><th>Convert/ Co-Fire Coal</th><th>Retire Coal</th><th>(Blend 1)</th><th>(Blend 2)</th><th>(Blend 4)</th><th>Exit Coal Earlier (Stakeholder)</th></tr>
<tr><td>Cayuga 1</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="6">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td colspan="2">Retire by 1/1/2030</td><td rowspan="2">NG Conversion by 1/1/2029</td></tr>
<tr><td>Cayuga 2</td><td colspan="2">Retire by 1/1/2031</td></tr>
<tr><td>Gibson 1</td><td rowspan="2">Co-fire by 1/1/2030</td><td rowspan="4">Retire by 1/1/2032</td><td colspan="2" rowspan="2">Co-fire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Gibson 2</td></tr>
<tr><td>Gibson 3</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2030</td></tr>
<tr><td>Gibson 4</td></tr>
<tr><td>Gibson 5</td><td colspan="6">Retire by 1/1/2030</td></tr>
<tr><td>Edwardsport</td><td colspan="6">NG Conversion by 1/1/2030</td></tr>
</table>

Note: Natural gas ("NG") conversion involves modifying existing infrastructure to use 100% natural gas fuel instead of coal for electricity generation. Co-firing involves infrastructure modification to use 50% natural gas fuel at the coal unit.

Resource Decisions Common to All Generation Strategies

As illustrated in Figure 2-7 above, the retirement of Gibson 5 by 2030 and the conversion of Edwardsport to 100% natural gas fuel were common assumptions across all generation strategies. Unit 5 has the oldest emissions controls of the Gibson units and is assumed to retire in 2029 (by 1/1/2030) in the modeling.[5] The Company evaluated CCS as a compliance option for Edwardsport under the EPA CAA Section 111 Rule in a strategy variation listed below and described further in Chapter 5 (Preferred Portfolio).

In addition to Edwardsport conversion and the retirement of Gibson 5, other resource changes common to each portfolio developed for the 2024 IRP include:

[5] Duke Energy Indiana will make any decisions related to Gibson 5 in concert with the joint owners of that unit.

- The 199 MW Speedway Solar project is expected to be completed by the end of 2025 and is added to all portfolios as of January 1, 2026.
- The 100 MW power purchase agreement ("PPA") for the Benton County wind farm will expire and is removed from all portfolios as of January 1, 2028.
- PPAs for several solar projects totaling approximately 25 MW in aggregate will expire over the next 13 years. These resources are removed from all portfolios as those contracts expire.
- Noblesville CC is retired in all portfolios as of January 1, 2035.

Strategy Variations

In addition to the generation strategies modeled in each worldview, the Company considered various "what ifs" and tested variations of certain generation strategies by changing a significant strategy decision or assumption to the capacity expansion model and allowing the model to select a different mix of resources. Perhaps the most significant of these is the "No 111" strategy variation, which the Company developed to evaluate a potential future in which the EPA CAA Section 111 Rule does not survive legal challenges, but Reference Case assumptions otherwise hold. The results for this variation are presented in Chapter 4. Additionally, the Company evaluated several variations of the Preferred Portfolio (Blend 2) to explore specific alternative generation strategy decisions and assess the relative impacts of that decision on the Preferred Portfolio. The results of this analysis are presented in Chapter 5.

Preferred Portfolio (Blend 2) strategy variations include:

- Prescribing a 2x1 combined cycle replacement at Cayuga rather than the two 1x1 combined cycles to evaluate the effect on total cost
- Prescribing a full natural gas conversion for Gibson 1 & 2 versus co-firing to evaluate impact on total cost and resource selection in the latter part of the planning period
- Evaluating the Reference Case assuming EPA CAA Section 111 Rule is repealed prior to implementation to identify potential course adjustments and inform development of a sufficiently flexible Short-Term Action Plan
- Prescribing the addition of small modular reactors ("SMR") late in the planning period to assess the impact on total cost
- Evaluating CCS as a compliance option under the EPA CAA Section 111 Rule for Edwardsport to assess the potential value of the associated tax credits
- Evaluating Edwardsport gas conversion by 2028 (rather than 2030, as required by the EPA CAA Section 111 Rule) to quantify changes in portfolio costs resulting from earlier gasifier retirement

Sensitivity Analysis

In addition to testing variations of a generation strategy, sensitivity analysis is performed to understand the impact of key externally driven uncertainties on portfolio resource choices and performance. Unlike scenario analysis, where many assumptions are changed simultaneously, sensitivity analysis stresses a single variable while holding all else constant to isolate the impact of that variable and provide insight into the associated risk. Key characteristics defining a sensitivity are listed in Figure 2-8 below.

Figure 2-8: Sensitivities

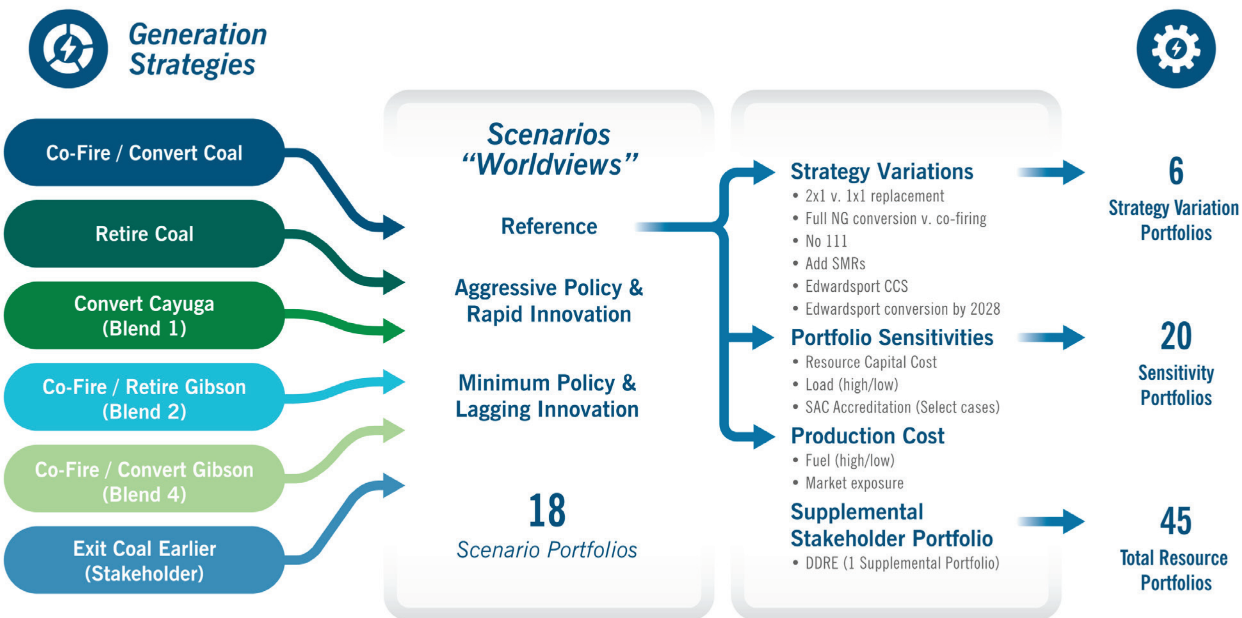
There is inherent uncertainty in all planning inputs and assumptions, and an unlimited range of many variables. Sensitivities are selected based on the qualities listed above in Figure 2-8. For the sensitivity analysis step, the Company tested deviations from the base forecasts for resource technology capital costs, load, and fuel prices. In addition, the Company performed a stochastic analysis to further evaluate risk associated with market exposure, which is discussed below. These sensitivities are described in more detail in Chapter 3.

Portfolio Matrix

Figure 2-9 below illustrates the 2024 IRP analytical framework for developing portfolios using the generation strategies modeled under three scenarios and evaluating various strategy variations and sensitivities.

This framework of extensive portfolio development analysis paired with additional production cost analytics allowed for a robust evaluation of the risks, uncertainties and potential trade-offs relative to the planning objectives described above. The evaluation of modeling results across the generation strategies is described in Chapter 4.

Figure 2-9: 2024 IRP Analytical Framework



Analytical Process & Tools

This section highlights the primary steps and tools involved in the IRP modeling process.

Modeling Software

Duke Energy Indiana utilized the EnCompass capacity expansion and production cost simulation software package ("EnCompass"), licensed through Yes Energy (formerly known as Anchor Power Solutions), as the primary modeling tool for the development and analysis of the IRP portfolios. The capacity expansion model and the production cost model are separate modules within EnCompass, as described in this section and Appendix C (Quantitative Analysis).

In addition to these primary tools, the Company utilized more granular reliability modeling tools as part of the overall modeling process to ensure consumer affordability and system reliability over the planning period.

Development of Modeling Assumptions

Duke Energy Indiana deploys a rigorous approach in developing input assumptions. The Company leverages various third-party software tools and sources, as well as internal subject matter experts and historical data, to develop modeling inputs. Chapter 3 describes each modeling assumption in detail.

Power Price Development

Near-term observable market prices and long-term fundamental projections are combined to develop power price forecasts. The Company uses EnCompass to develop long-term fundamental power price projections based on scenario-specific fuel price forecasts, technology assumptions, resource assumptions, and Horizon Energy's National Database, which provides the existing resource mix for the Eastern Interconnect, as well as a comprehensive dataset of hourly load shapes, dispatch, and prices across all modeled regions.

The Company used Horizon Energy's database within EnCompass to develop scenario-specific expansion plans for the whole Eastern Interconnect, which includes the entire MISO service territory and neighboring systems. The expansion plans are then run on an hourly basis to estimate the 20-year hourly power price for Duke Energy Indiana. This method ensures consistency between the power price forecasts and the Duke Energy Indiana EnCompass runs with regard to key assumptions such as fuel and load.

Capacity Expansion Modeling

The capacity expansion model is used to determine the least-cost mix of portfolio resources to meet customer energy and peak demand needs over the planning horizon. The model seeks to develop a portfolio of resources that will minimize overall system costs, inclusive of capital costs, for new resources as well as ongoing operation, maintenance, and fuel costs.

Capacity expansion examines numerous permutations of possible resource options that meet system needs for each portfolio. Given the vast number of resource options examined in this phase of the analysis, the capacity expansion screening model uses a simplified, average representation of hourly system demand to screen for the optimal resource portfolio.

Production Cost

The portfolio of resources developed using the capacity expansion model is then evaluated in the production cost model. This model uses detailed, hourly granularity over the planning horizon to simulate the commitment and dispatch of system resources to meet the weather normal hourly load requirements of the system consistent with least-cost system operations. This level of detailed analysis allows for modeling resources with specified generation profiles or other detailed operating characteristics.

Completion of this step produces preliminary portfolios that satisfy the planning reserve margin requirement and least-cost objectives. The results from the production cost runs are the basis for the economic and rate impact analysis, as this model calculates the revenue requirement of resource plans over the planning period. The detailed hourly production cost model is also utilized for sensitivity analyses of selected portfolios.

Enhanced Reliability Evaluation & Risk Analysis

New to the 2024 IRP analytical process, the Company performed an Enhanced Reliability Evaluation on the production cost modeling results to more robustly assess resource adequacy and the relative ability of potential resource plans to serve Duke Energy Indiana customer demand in a variety of real-world grid conditions. This evaluation generated thousands of simulations as part of a probabilistic reliability analysis using the Strategic Energy Risk Valuation Model, the same model MISO uses in its own probabilistic planning analyses. Key features of the enhanced reliability modeling include weather uncertainty simulation, unit availability uncertainty simulation, economic load forecast error, and 8760 production cost simulation.

MISO member utilities offer their units into the market rather than dispatch generation directly to serve customer load. However, the future resource mix and capacity accreditation framework of the broader MISO market is inherently uncertain, which highlights the need for Duke Energy Indiana's resource portfolios to closely align with Duke Energy Indiana's customer load. The ultimate purpose of this step is to ensure that Duke Energy Indiana future resource portfolios contribute their fair share to the MISO market and do not place undue burden on the rest of the system. This evaluation provides reasonable assurance that the final portfolios perform at levels of reliability sufficient to serve Duke Energy Indiana customers regardless of the resource changes of other MISO participants. Appendix E discusses the Enhanced Reliability Evaluation modeling in further detail.

In addition, a new stochastic economic analysis was performed in the 2024 IRP using PowerSIMM to assess the impact of uncertainty around future market conditions. The PowerSIMM production cost model from Ascend Analytics is designed for high granularity simulation of an electric power system, using a specified set of resources established in the capacity expansion model to perform a detailed hourly forecast of generation similar to the detailed Encompass production cost model. However, PowerSIMM performs hundreds of iterations based on varied weather, load, solar, wind, forced outages, fuel, and power prices simulated by iteration. This stochastic analysis produced a range of outcomes for each generation strategy for key output variables such as net market purchases, CO_2 emissions and operating costs.

The results of the Enhanced Reliability Evaluation and stochastic risk analyses are presented in Chapter 4 and further detailed in Appendix C.

Advancements in Analytical Process

Key Advancements in the 2024 Integrated Resource Plan

In addition to the integration of the Five Pillars, the 2024 Integrated Resource Plan incorporated feedback received from stakeholders and the Indiana Utility Regulatory Commission ("IURC" or the "Commission") in the "Director's Report for Duke Energy Indiana's 2021 Integrated Resource Plan" and introduces new planning elements and approaches in response to evolving economic conditions, policies, and technologies. This commitment to continuous planning and improvement ensures the IRP remains relevant and effective.

Incorporation of Federal Legislation

Recent federal actions since the previous IRP highlight just how much is changing, with the passage of the Infrastructure Investment and Jobs Act ("IIJA") and Inflation Reduction Act of 2022 ("IRA") providing historic levels of investment and tax incentives for renewables, transmission, nuclear, hydrogen, and vehicle electrification, and the passage of EPA Clean Air Act Sections 111(b) and (d) in the May 2024 Final Rule regulating greenhouse gas emissions from existing coal and new natural gas generation facilities.

Duke Energy Indiana carefully considered the EPA CAA Section 111 Rule and incorporated various permutations of compliance pathways into the modeled generation strategies in this IRP. The Company equally considered the tax incentives and funding available under the IRA and IIJA. IRA production tax credits and investment tax credits are modeled in this plan. All related assumptions are detailed in Chapter 3.

Improved Stakeholder Engagement & Data Sharing

Since the previous IRP, Duke Energy Indiana has enhanced its stakeholder engagement process and incorporated practices observed among peers. Duke Energy Indiana retained 1898 & Company, an experienced third-party consultant and facilitator, to advise the Company in its effort to meaningfully collaborate with interested parties. Together with 1898, Duke Energy Indiana devoted significant attention to creating a comprehensive engagement process designed to prioritize broad, transparent, and inclusive stakeholder participation. One of the major improvements includes the increased transparency and accessibility of the detailed modeling files and data used to create the 2024 IRP. Utilizing the online data sharing platform Datasite, the Company provided technical stakeholders with more than 650 modeling input and output files as the process evolved, ensuring comprehensive access to data earlier in the stakeholder process. This improvement is complemented by a more inclusive approach to stakeholder engagements, with the Company prioritizing diverse perspectives and striving for more meaningful and balanced dialogue than in previous IRPs.

In addition, Duke Energy Indiana has enriched the content of its meetings, incorporating more detailed information into presentations and fostering an environment conducive to open discussions. The Company has made strides in improving the tone and inclusiveness of its interactions, actively encouraging feedback with dedicated time for topical and open Q&A throughout the meetings and ensuring that all participants – regardless of their technical expertise – had multiple avenues for engagement, including oral comments, written submissions, and shared information. All stakeholder feedback throughout the process was thoughtfully considered and, in many cases, incorporated into the 2024 IRP key assumptions and scorecard evaluation metrics.

Another notable new feature of the 2024 IRP process is the introduction of technical meetings held prior to public forums, aimed at addressing complex and detailed resource planning modeling assumptions and methodologies for those stakeholders who, by virtue of their experience, have a deep level of technical understanding. These enhancements reflect Duke Energy Indiana's commitment to a more transparent, inclusive, and responsive stakeholder engagement process.

Increased Use of Publicly Available Data & Proprietary Data Blending

In addition to enhancing its approach to data sharing since the 2021 IRP, the Company has incorporated more publicly available data into its modeling assumptions and has blended proprietary data inputs such as cost curves from multiple sources. This strategy has enabled the Company to share more detailed and transparent content during stakeholder meetings and within the IRP document itself. As a result, stakeholders have been better equipped to evaluate the 2024 IRP modeling assumptions throughout the entire process.

Evolving MISO Capacity Accreditation Methodology

In June 2023, MISO moved from an annual to a seasonal resource adequacy framework. The Seasonal Accredited Capacity ("SAC") construct values resources differently during the four seasons of the planning year: summer, fall, winter, and spring. This shift, effective with the 2023/2024 planning year, recognizes that the grid faces increasing variability of reliability challenges throughout the year due to factors including baseload generation retirements, higher penetration of intermittent resources, extreme weather events, and declining excess reserve margins. The 2024 IRP has incorporated the foundational elements of MISO's change from annual to seasonal resource adequacy in its modeling, allowing for more precise planning and resource selection based on the specific needs and resource availability of each season.

Beyond the transition to a seasonal resource adequacy framework, MISO submitted a new probabilistic capacity accreditation framework to the Federal Energy Regulatory Commission, in February 2024. If approved, this new Direct Loss-of-Load ("DLOL") modeling framework would take effect in the 2028/2029 planning year.

The 2024 IRP has included best-available information on the potential capacity accreditation changes of future resources under MISO's existing SAC construct and proposed DLOL methodology. In the base case, the modeling assumes the SAC construct applies through planning year 2027/2028 and the DLOL method is implemented beginning in the 2028/2029 planning year, as proposed. In addition, analysis was performed to evaluate the impact of SAC remaining in effect throughout the IRP planning horizon. This approach, including the Reference Case assumption and sensitivity analysis, was defined as part of stakeholder discussions and aligns with the feedback received from technical stakeholders. Looking ahead, Duke Energy Indiana will continue to closely monitor potential MISO construct changes and evaluate potential impacts to reliability and capacity needs to ensure compliance with new requirements.

Transition to Winter Planning in the Near Term

Since the previous IRP, Duke Energy Indiana moved from summer planning to winter planning in the MISO capacity auction. This transition to winter planning was largely driven by MISO's implementation of the SAC construct discussed immediately above, which introduces seasonal resource adequacy requirements. This change was projected in the Company's previous IRP. As more intermittent resources are added to the MISO system, in particular solar, reliability risk is shifting to cold winter hours, particularly in the early morning and evening. Over time, winter reserves may become more constrained given that solar generation output is less coincident with peak loads in the winter period.

While Duke Energy Indiana's coincident summer peak load remains higher than its coincident winter peak load, the planning season load obligation is driven by coincident peak load plus the planning reserve margin ("PRM"). Under SAC, with the associated seasonal PRM, the Company's winter peak load plus winter PRM may more frequently tend to be greater than its summer peak load plus summer PRM. The tendency of Duke Energy Indiana's system to be winter planning may also be affected by the proposed change to DLOL.

The seasonal planning reserve margin assumptions are detailed in Chapter 3.

Enhanced Reliability Evaluation & Measurement

As discussed earlier in this Chapter, Duke Energy Indiana introduced an enhanced evaluation of reliability in the 2024 IRP analytical process to further test the ability of future resource portfolios to serve customer demands under a variety of real-world conditions and assess the resource adequacy of potential plans. This analysis included running a probabilistic set of simulations to evaluate the relative ability of the modeled portfolios to meet customer demand under a variety of real-world uncertainties. Appendix E discusses the Enhanced Reliability Evaluation in further detail. Results of this analysis are included in Chapter 4 and Appendix C.

In addition to the new resource adequacy modeling strategies introduced in this IRP cycle, system planners and reliability modelers assessed additional measurements of reliability to properly characterize new system risks. Beyond Loss of Load Expectation, new metrics such as EUE were evaluated to better illustrate how different resource portfolios can create risks of different magnitude, frequency, and duration as new resources carry different risk profiles. These measurements are discussed in more detail in Appendix E and Appendix C.

Introduced New Stochastic Risk Analysis

Beyond the Enhanced Reliability Evaluation, the 2024 IRP incorporates additional new stochastic risk analyses to explore and quantify selected market and operational risks. In contrast to the deterministic scenario and sensitivity analyses performed using the EnCompass model, the stochastic models use historical uncertainty and forward market volatility to generate hundreds to thousands of simulations which vary key inputs, such as market prices, meteorology, loads and unit outages. The portfolios are dispatched in each of these simulations of future years to produce statistical distributions (averages and ranges around the average) of key metrics such as energy sufficiency, market net purchases, operating costs, and emissions. Results of the stochastic risk analysis are presented in Chapter 4 and further detailed in Appendix C.

Advancing Modeling Framework Through Worldview Scenarios & Generation Strategies

Duke Energy Indiana "returned to the whiteboard" to develop its 2024 IRP modeling framework. As discussed earlier in this Chapter, this framework includes six generation strategies evaluated under three scenario "worldviews." Scenario analysis included capacity expansion modeling for a total of 18 scenario portfolios. In addition, the Company evaluated multiple strategy variations and sensitivities. Generation strategies, worldviews, and strategy variations are a new addition to the IRP framework and reflect Duke Energy Indiana's continued evolution of the modeling framework to improve resource planning analysis and incorporate significant changes in the planning landscape. In particular, the worldviews reflect a more dimensional evaluation of how the landscape could unfold in the future.

Refined Alternate Load Forecast Scenarios

The core priority for an IRP is to design a resource portfolio that will reliably serve load throughout the planning period. Like the 2021 IRP, Duke Energy Indiana tested each candidate portfolio under a high load and low load sensitivity; however, since the 2021 IRP, the Company has applied a more rigorous approach to developing the high and low load forecast scenarios. Rather than apply a standard deviation from the mean of the base load forecast, the Company developed detailed assumptions for high and low load encompassing economic growth, electric vehicle adoption, behind-the-meter solar adoption, and economic development. Notably, the Company included significant data center load above and beyond the greater economic development load assumed in the 2024 IRP high load forecast. The assumptions and framework leveraged to craft the alternate load forecasts are described in Appendix D (Load Forecast). The additional rigor used to develop the load sensitivities enables the Company to test portfolios against the potential for significant economic development growth in Indiana.

Providing Expanded Load Forecasting Methodology Discussion & Data

In response to feedback from the Director on the previous IRP, this IRP includes an expanded discussion with more detailed data on load forecasting results and methodologies. This encompasses inputs, tools, and methodology for developing load forecasts by customer class and provides a more in-depth explanation of how industrial load is projected. The Company has also significantly enhanced its discussion of the methodology and assumptions for forecasting electric vehicle load and behind-the-meter generation, emphasizing how these load modifiers influence each alternative load forecast scenario. The Company aimed to ensure that the methodology, data, and assumptions presented in this IRP are robust and transparent, allowing for comprehensive evaluation. This expanded discussion can be found in Appendix D.

Improved Discussion of Demand-Side Management & Market Potential Study

Similar to the expanded load forecasting discussion and data included in this IRP, the Company has provided more detailed information on the Market Potential Study and demand-side resource modeling performed. This includes the process of creating energy efficiency bundles, the resulting bundles incorporated into the 2024 IRP modeling, and the model's selection of these bundles across the generation strategies. These details are included in Appendix H (Demand-Side Resources & Customer Programs).

Studying Carbon Capture & Sequestration Technology at Edwardsport

In addition to the combined cycles evaluated in the 2024 IRP, combined cycle with CCS is a technology under evaluation that may play a role in a carbon-constrained energy system. The performance and cost of CCS on combined cycle considered in this IRP are based on generic unit estimates and engineering judgement.

CCS technology for both natural gas- and coal-fired units continue to be evaluated throughout the United States as a low-carbon technology deployment option. In 2023, the Department of Energy ("DOE") selected among competitive applicants for CCS studies and full-scale demonstrations for a FEED study award. Duke Energy Indiana was awarded a cost-share grant for one such full-scale FEED study at the Edwardsport IGCC facility, which is one of the cleanest and most efficient coal-fired power plants in the world. Two full-scale natural gas-fired CCS demonstrations were also selected for potential DOE cost-share grant funding. At Edwardsport, the post-combustion capture system will be designed to enable maximum fuel flexibility, from coal-gasified syngas, natural gas and syngas/natural gas blends. In July 2024, the DOE approved the Edwardsport CCS FEED study to enter budget period two, which includes the detailed engineering and full project cost estimate. The study is expected to be completed in 2026. This effort showcases Duke Energy Indiana's continued commitment to advancing cleaner emerging generation technologies and will help the Company to further refine its planning assumptions related to the costs and operating characteristics of CCS systems in future resource plans.

CCS is highly dependent on local and regional geology, and the site-specific information will dictate the potential to be an economical supply-side option. Retrofit of existing generation, both natural gas- and coal-fired, can extend the life of operating plants while moving toward lower CO_2 emissions goals. CCS will continue to be monitored by Duke Energy Indiana and evaluated as a decarbonization technology to meet future low-carbon requirements.

Future Advancements in Analytical Process

With each IRP, the Company takes the lessons learned from previous IRPs and thoughtfully considers feedback from stakeholders, the IURC and Commission Staff. Between the submission of the 2024 IRP and the beginning of the 2027 IRP, the Company will continue to work with involved parties to explore specific improvement opportunities such as those outlined below. This includes continuing to closely monitor emerging issues through the IURC's Contemporary IRP Issues Forum, as well as industry conferences and organizations such as the Electric Power Research Institute.

All potential future improvements to the analytical process are subject to change and will be evaluated for their relevance and ultimate value to the process, with consideration for any meaningful changes in policy, requirements, or technical capabilities that occur in the three years following this IRP.

Measurements of Resiliency & Stability

Throughout the industry, there is increasing attention and focus on natural and man-made disasters with a high-impact low-frequency property in electric power systems. A power system must be built with “resilience” or the ability to withstand, adapt and recover from these off-nominal events. Resilience metrics are tools to measure the resilience level of a power system, normally employed for resilience cost-benefit in planning and operation. While various resiliency metrics have been presented in power system literature, there is still a lack of a comprehensive framework regarding resiliency metrics for integrated resource planning, and existing frameworks have fundamental shortcomings.

There is ongoing work in the industry to translate resiliency into metrics and a modeling framework. Further evaluation is required to potentially score resiliency configuration characteristics, including those that support state policy goals. Without a clear definition of resilience and specific metrics with which to evaluate resilience improvements, so far, the IRP requirement has been open-ended, subject to interpretation, and, thus, difficult to address systematically in integrated resource planning.

As noted by the Director in the IURC’s Director’s Report for AES Indiana’s 2022 IRP, “the reliability, stability, and resiliency set of metrics are a relatively recent addition to Indiana utility IRPs... The basic methodology is evolving from one IRP to the next as can be expected depending on the specific utility circumstances.”[6] While long-term resource planning has limited capability to address immediate grid operations issues, Duke Energy Indiana will continue to monitor developments and explore opportunities to further refine resiliency and stability measures that could be incorporated in future IRPs.

Electric Vehicle & Data Center Load Modeling

In response to stakeholder feedback received throughout the IRP process, Duke Energy Indiana intends to explore methods for enhanced modeling of electric vehicle and data center loads to account for the characteristics and unique profiles of these emerging load types.

Continue to Refine Probabilistic & Stochastic Analysis

In addition to the general improvement in EV and Data Center modeling referenced above, the Company intends to explore methods of improving the characterizations of these loads in the Enhanced Reliability Evaluation introduced in this IRP, as the shape and weather-responsiveness of these loads may drive or mitigate periods of risk. In addition, the Company will continue to evaluate the historical dataset on which these analyses are based and consider whether it is reasonable to make adjustments to probabilistic weightings or sample size.

[6] Indiana Utility Regulatory Commission, Final Director’s Report for AES Indiana’s 2022 Integrated Resource Plan, August 26, 2024, available at https://www.in.gov/iurc/files/Directors-Final-AES-IRP-Report-8-14-24.pdf.

Chapter 3: Key Assumptions

Highlights

- Against a backdrop of profound transformation in the energy landscape, Duke Energy Indiana's commitment to iterative, continuous planning is critical to managing risk and uncertainty for an orderly energy transition. The Integrated Resource Plan considers the recent consequential changes in the marketplace and regulatory environment to develop key forward planning assumptions.

- The 2024 Integrated Resource Plan is supported by robust quantitative analytics based on inputs and assumptions from a range of industry-leading sources and Duke Energy Indiana subject matter experts.

- Duke Energy Indiana reviewed modeling inputs and assumptions with stakeholders throughout the development of the resource plan, during public engagement sessions and through comprehensive data sharing with technical stakeholders. All stakeholder feedback was thoughtfully considered and, in many cases, incorporated into the key assumptions described in this Chapter.

Development of Modeling Assumptions

This Chapter discusses the key inputs and assumptions relied upon in the development of Duke Energy Indiana's 2024 Integrated Resource Plan ("IRP" or the "Plan"). Duke Energy Indiana (or the "Company") is committed to continuously evaluating and updating modeling inputs and assumptions to best reflect industry and market conditions, both in the short term and over the planning horizon.

Duke Energy Indiana conducts a robust process to identify and define key inputs and rigorously evaluates the assumptions and forecasts that drive the IRP modeling. The Company leverages internal subject matter experts, as well as external data sources, and vets material assumptions with stakeholders. The inputs, assumptions, and modeling framework used to develop the 2024 IRP represent a snapshot in time and are subject to change in future IRPs, especially given the dynamic nature of the energy industry, as well as the changing dynamics of various resource supply chains, both domestically and globally. The Company uses reasonable inputs and assumptions for generic long-term planning assumptions that are founded in the best information available at the time modeling is undertaken, recognizing that actual project-specific costs, configurations, operating characteristics, and transmission requirements will be refined in plan execution. Supply-side and demand-side resources included in planning analytics are necessarily generic, reflecting a representative sample of the wide range of potential unit sizes, configurations, or specific technology designs that may be deployed. Plan execution is discussed further in Chapter 6 (Short-Term Action Plan).

Additional detail on modeling assumptions is provided in Appendix C (Quantitative Analysis) as well as other appendices referenced herein. All forecasts and analysis in the 2024 IRP are developed for the 20-year future planning period.

Reliability Requirements

Preserving reliability and ensuring resource adequacy are fundamental to resource planning, and the energy transition is reshaping how resource planners approach reliability. With a power market increasingly reliant on intermittent resources, there is a need for continuous improvement in developing reliability modeling assumptions. As a member of the Midcontinent Independent System Operator (“MISO”), Duke Energy Indiana must adapt to evolving market rules and requirements. Key reliability inputs needed in resource modeling include planning reserve margins, resource accreditation, and effective load carrying capability (“ELCC”) values. These inputs are foundational resource planning components that ensure Duke Energy Indiana is maintaining or improving upon the adequacy and reliability of the existing grid.

Planning Reserve Margin Requirement

MISO requires Duke Energy Indiana and other member utilities to meet a seasonal planning reserve margin requirement (“PRMR”). The PRMR is the amount of capacity that each load serving entity (“LSE”) must procure above its projected peak demand to ensure that it has sufficient resources to reliably serve customers in all seasons. Figure 3-1 below provides the formula used to calculate the PRMR for each LSE in megawatt (“MW”) terms based on the overall MISO reserve margin (“PRM”), expressed in percentage terms. The PRMR is supplemented by the Local Clearing Requirement, which mandates how much of the PRMR must be met by generation resources located within the LSE’s local resource zone in each season.

Figure 3-1: Simplified Planning Reserve Margin Requirement Calculation

$$\text{LSE PRMR (MW)} = \text{Coincident Peak Demand Forecast (MW)} \times \left[1 + \text{Transmission Loss \%}\right] \times \left[1 + \text{MISO PRM \%}\right]$$

Current Seasonal Accredited Capacity Construct

Beginning with the 2023/2024 planning year, MISO introduced a Seasonal Accredited Capacity (“SAC”) construct for resource adequacy. SAC sets parameters on a four-season basis for both accreditation and determination of PRMR. SAC now accredits thermal resources seasonally based on their level of performance during higher risk hours, as opposed to the historical annual equivalent forced outage rate (“EFOR”) unforced capacity value (“UCAP”) based approach. MISO defines the “Tier 2” Resource Adequacy hours as the highest risk hours and includes declared Maximum Generation Emergency hours plus a percentage of other defined “tight margin” hours. Thermal resource accreditation is weighted toward resource performance in these hours. The “Tier 1” hours include all hours that are not defined as “Tier 2.” This approach rewards resources that perform better during these critical “Tier 2” hours and penalizes those that do not. The accreditation of other resource types, including renewable energy resources, is also now seasonal.

Another aspect of the SAC construct is the creation of the “31-Day Rule” for planned outages within a season. The 31-Day Rule requires that if capacity that has cleared in the auction in a season is in planned outage for more than 31 days in that season, it must be replaced with uncleared capacity. In lieu of this physical replacement, the generator can opt to pay a fee, defined as the capacity replacement non-compliance charge. If applicable, generators are allowed to incorporate this charge into their capacity offers to reflect the future cost of these outages in the capacity auction. The Company attempts to manage its planned outage schedule to minimize the number of outages longer than 31 days. As such, the 31-Day Rule is not modeled in the IRP.

Proposed Direct Loss of Load Methodology for Resource Accreditation

As an ongoing evolution of the SAC methodology, MISO has filed with the Federal Energy Regulatory Commission (“FERC”) for approval to implement an ELCC-based approach for resource adequacy known as Direct Loss of Load (“DLOL”), beginning with the 2028/2029 planning year. DLOL is a two-step process in which expected marginal contribution to reliability is determined for each resource class, and then that class-level accreditation is allocated to individual resources within the class based on recent history, using the SAC “Tier 2” hours methodology. This process can be summarized first by determining the “size of the pie” (total accreditation of the resource class) followed by “divvying up the pie" (allocation to the individual resources within the class). MISO has proposed numerous resource classes for the DLOL approach, including separate classes for coal units, natural gas units, solar, wind, hydro, energy storage, and others.

This process will produce seasonal class averages of the different resource types. It is also expected that these class averages may change with time as the total installed capacity ("ICAP") of each resource class changes as a portion of the MISO system. MISO has provided indicative class performance (current UCAP to ICAP ratio under the SAC construct, and proposed DLOL to ICAP ratio) based on planning year 2023/2024 data. These are provided in Table 3-1 below.

Table 3-1: Current & Proposed MISO Accreditation by Resource Class

Resource Class	Summer		Fall		Winter		Spring	
	SAC[1]	DLOL	SAC[1]	DLOL	SAC[1]	DLOL	SAC[1]	DLOL
Gas excl. CC[2]	90%	88%	84%	88%	79%	66%	84%	69%
Combined Cycle	91%	90%	94%	89%	90%	74%	92%	75%
Coal	92%	91%	91%	88%	90%	73%	89%	74%
Hydro	96%	96%	94%	96%	93%	92%	97%	88%
Nuclear	95%	90%	96%	85%	95%	86%	92%	80%
Pumped Storage	99%	98%	91%	98%	94%	50%	89%	67%
Storage	95%	94%	95%	93%	95%	91%	95%	95%
Solar	45%	36%	25%	31%	6%	2%	15%	18%
Wind	18%	11%	23%	15%	40%	16%	23%	16%
Run of River	100%	100%	100%	100%	100%	100%	100%	100%

Note 1: Current numbers under the SAC construct represent UCAP for thermal resource class and average ELCC starting values for solar and wind resource classes.
Note 2: MISO has adjusted the gas resource class by removing combined cycle resources.
Source: MISO, Market Redefinition: Accreditation Reform, RASC, February 28, 2024

Per its FERC deficiency letter response filing on August 26, 2024, MISO may also add a dual fuel gas/oil class to the resources used in DLOL calculations. This information was not available at the time of the modeling for this IRP.

Effective Load Carrying Capability

The MISO class average accreditation values shown in Table 3-2 above are used as the starting point for each resource in the IRP modeling. For thermal and storage units, the initial value does not change over time since these are dispatchable resources that are available to meet load when not in planned maintenance or forced outage. However, due to the variable nature of solar and wind resources, it is crucial to understand the reliable capacity contributions of these resources in the planning process. The amount a resource can be counted on at periods of system stress is reflected in its ELCC. Unlike thermal units, the ELCC values of solar and wind resources will vary over time, depending on the total capacity of those resources connected to the grid. Duke Energy Indiana retained 1898 & Co. to develop ELCC curves used in modeling and development of the 2024 IRP. Refer to Appendix C for more detail on ELCC and the accreditation values used in modeling.

Planning Reserve Margin Requirement Under Direct Loss of Load Methodology

In establishing the PRMR under DLOL, MISO has proposed to use the DLOL resource accreditation values instead of the EFOR-based UCAP values used in previous methodologies, starting in MISO planning year 2028/2029. This ensures that the amount of capacity purchased by LSEs is commensurate with the accreditation of resources.

Because the DLOL total class accreditation is expected to be lower than traditional UCAP values, it is expected that MISO will also require a lower planning reserve margin under DLOL than in years past. The indicative PRM under DLOL can even be negative in some seasons. This implies that all uncertainty in load service has been embedded in the accreditation value of resources, and hence little or no reserve margin is required to be applied to the coincident peak load for further conservancy.

Table 3-2: Non-Coincident Planning Reserve Margin Used in IRP Modeling

Accreditation Methodology	Non-Coincident Planning Reserve Margin			
	Winter (Dec-Feb)	Spring (Mar-May)	Summer (Jun-Aug)	Fall (Sep-Nov)
SAC	16.8%	21.8%	5.6%	9.3%
DLOL	-5.8%	-2.7%	1.0%	4.5%

Duke Energy Indiana models a non-coincident peak load forecast in the 2024 IRP, thus the seasonal planning reserve margins presented in Table 3-2 above incorporate both the coincident PRM and the seasonal peak coincidence factors for MISO Local Resource Zone 6 (Duke Energy Indiana is in Zone 6). Duke Energy Indiana's non-coincident peak load is higher than its peak load coincident with the MISO peak, which causes the effective PRM on a non-coincident peak basis to be lower than MISO's PRM at the coincident peak.

Market Reliance

To ensure that none of the candidate resource portfolios developed for the IRP are overly reliant on the MISO energy market to serve customer load, the Company includes a requirement in the capacity expansion model that all candidate resource portfolios must be able to supply at least 75% of annual customer energy needs from Duke Energy Indiana resources. This constraint is enforced beginning in the 2030 study year. The constraint is important for portfolio development in the capacity expansion model, but it is not applied in the production cost model, which simulates hourly dispatch of the portfolio. This allows economic dispatch of Duke Energy Indiana resources as well as economic purchases and sales through participation in the MISO energy market. The Company performed additional stochastic analysis to assess cost risk associated with MISO energy market exposure. The results of this analysis are presented in Chapter 4 (Candidate Resource Portfolios) and are further detailed in Appendix C.

Load Forecast

Forecasted customer demand provides the basis for developing candidate resource portfolios, influencing the type, scale, and timing of resource changes. The Company prepares forecasts for annual energy and seasonal peak demand as part of the planning process, using a methodology (statistically adjusted end-use models and ordinary least squares regression analysis) relating sales to growth in number of households, inflation-adjusted income, employment levels, inflation-adjusted electric rates, market-driven efficiency and electrification trends, and policy-driven efficiency and electrification trends. The Company's load forecasting methodology and framework are described in greater detail in Appendix D (Load Forecast). In the load forecast for the 2024 IRP, the Company is projecting steady industrial sector demand growth driven by economic development, particularly manufacturing expansion. High load factor industrial customers require reliable, around-the-clock energy supply, a need that is reflected in the candidate resource portfolios presented in Chapter 4.

The load forecasting framework includes a national economic forecast, a service area economic forecast, weather data analysis, and the electric load model. The economic forecasts include projections of economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income levels. Moody's Analytics, a leading national economic consulting firm, provides historical data and forecasts of key economic and demographic variables for the load forecast model. The economic forecast, key account insights, economic development project assessments, and normal weather assessments are used together with the energy and peak demand models to produce the electric load forecast. The compound annual growth rate ("CAGR") of key economic trends over the next 10- and 20-year periods are presented in Table 3-3 below.

Table 3-3: Summary of Annualized Growth Rates for Key Economic Drivers

Driver	2025-2034 CAGR	2025-2044 CAGR
Households (Population)	0.60%	0.42%
Real Median Income	0.93%	1.01%
Real GDP Nonmanufacturing	2.23%	0.34%
Real GDP Manufacturing	2.09%	1.74%
Residential Electric Rates[1]	-4.26%	-1.39%
Commercial Electric Rates[1]	-3.72%	-0.85%
Industrial Electric Rates[1]	-5.67%	-2.79%
Economic Development Projects Energy Growth	9.53%	8.28%

Note 1: Growth in electric rates based on 2023 dollars (adjusted for inflation).

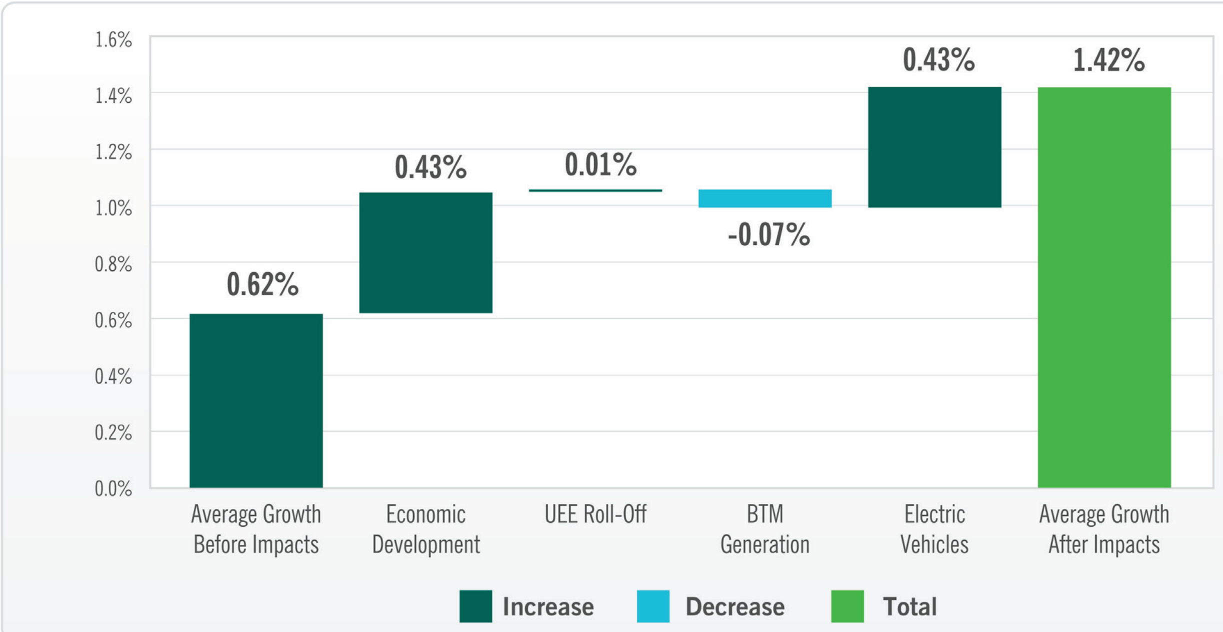
Growth in economic drivers of the three major sectors – residential (households), commercial (real GDP nonmanufacturing), and industrial (real GDP manufacturing) – contributes to growth in electric sales over the forecast horizon. Declines in electric rates relative to inflation provide an additional growth impact on electric sales as customers adjust energy consumption based on electric rates. Economic development impacts to the forecast ramp up from 2025 to 2034 and remain flat from 2034 to 2044. Economic development impacts refer to growth over and above what is already anticipated for the service area according to the Moody's Analytics forecast.

Load Modifiers

Independent forecasts for electric vehicle ("EV") adoption and behind-the-meter ("BTM") generation are key load modifiers in the forecast. The load forecast is also adjusted to account for expected near-term major load additions resulting from economic development wins within the Company's service territory. Duke Energy Indiana's load forecasting group works with the economic development team to identify the likely and expected new load from economic development projects and includes a portion of this expected future load in the load forecast. Incorporation of economic development projects in the load forecast is discussed further in Appendix D.

EVs and BTM generation are expected to significantly impact Duke Energy Indiana's net retail load over the 20-year planning period. New utility energy efficiency ("UEE") programs are included as a selectable resource in the capacity expansion model and are not reflected in the load forecast, however, contributions from existing UEE programs are deducted from the load forecast to avoid double counting as those programs reach end of life and are overtaken by naturally occurring efficiency trends. Figure 3-2 below shows the impact of these load modifiers on the baseload forecast through 2034. Table 3-4 below shows the annual impacts, measured in gigawatt hours ("GWh"), of load modifiers on the baseload forecast and provides net retail sales at meter, gross retail sales at generator, wholesale sales, and total system obligation at generator.

Figure 3-2: Load Modifier Impacts on Compound Annual Growth in Retail Sales (2025-2034)



Electric Vehicles

EVs currently comprise roughly 5%-6% of total vehicle sales in Duke Energy Indiana's service territory. They are forecasted to grow to 38% of vehicle sales by 2030 and over 77% of vehicle sales by 2040. Appendix D provides more detail about the EV forecasting methodology and the net load impact of EVs for the base, low, and high load forecasts used in the IRP analysis.

Behind-the-Meter Generation

Adoption of BTM solar is projected to steadily increase in the Duke Energy Indiana service territory throughout the forecast period, with a 20-year CAGR of approximately 7%. Energy from BTM generation is expected to grow from less than 0.5% of load currently to nearly 1.5% of load over the 20-year planning horizon. Appendix D provides detail on the BTM solar forecasting process and the net load impact of BTM generation on the base, low, and high load forecasts used in the IRP analysis.

Utility Energy Efficiency Historic Roll Off

The efficiency savings associated with existing UEE programs are deducted from the load forecast (potential future programs are included as selectable options in the capacity expansion modeling and are not reflected in the load forecast). Over time, as naturally occurring efficiency gains overtake the existing utility programs, these savings become part of the basic load and no longer need to be deducted. Table 3-4 below lists the "roll off" of these savings from UEE programs to naturally occurring efficiency trends, which continue to reduce forecasted load on an enduring basis. Additional detail on the incremental savings from new UEE programs is provided in Appendix H (Demand-Side Resources & Customer Programs).

Table 3-4: Forecasted Energy Sales – System Obligation at Generator (GWh)

Year	Base Retail Sales	Economic Dev.	UEE Historic Roll Off	Rooftop Solar	Electric Vehicles	Net Retail Sales at Meter	Line Loss + Company Use	Gross Retail at Generator	Wholesale	System Obligation at Generator
2025	27,350	917	20	-26	36	28,297	2,303	30,600	2,493	33,093
2026	27,565	1,538	37	-44	77	29,172	2,373	31,545	1,954	33,499
2027	27,845	2,055	55	-63	131	30,023	2,441	32,464	1,983	34,447
2028	28,068	2,087	71	-82	202	30,347	2,467	32,814	2,102	34,916
2029	28,245	2,081	86	-101	294	30,604	2,488	33,092	1,715	34,807
2030	28,452	2,081	92	-122	413	30,915	2,513	33,428	1,787	35,215
2031	28,616	2,081	90	-143	570	31,213	2,537	33,750	1,787	35,537
2032	28,801	2,081	79	-165	757	31,553	2,564	34,117	1,787	35,904
2033	28,893	2,081	63	-186	967	31,818	2,585	34,403	1,787	36,190
2034	29,013	2,081	44	-206	1,195	32,126	2,610	34,736	1,787	36,523
2035	29,131	2,081	28	-224	1,437	32,453	2,636	35,089	1,787	36,876
2036	29,295	2,081	14	-242	1,689	32,837	2,667	35,504	1,787	37,291
2037	29,351	2,081	6	-258	1,946	33,126	2,690	35,816	1,787	37,603
2038	29,462	2,081	2	-275	2,204	33,474	2,718	36,192	1,787	37,979
2039	29,579	2,081	0	-293	2,463	33,830	2,747	36,576	1,787	38,363
2040	29,742	2,081	0	-310	2,720	34,232	2,779	37,011	1,787	38,798
2041	29,800	2,081	0	-327	2,902	34,455	2,797	37,252	1,787	39,039
2042	29,915	2,081	0	-345	3,105	34,756	2,821	37,577	1,787	39,364
2043	30,043	2,081	0	-362	3,323	35,084	2,847	37,932	1,787	39,719
2044	30,234	2,081	0	-382	3,564	35,497	2,880	38,378	1,787	40,164
CAGR 2025-2034	0.7%	9.5%	9.2%	25.9%	47.6%	1.4%	1.4%	1.4%	-3.6%	1.1%
CAGR 2025-2044	0.5%	4.4%	—	15.2%	27.3%	1.2%	1.2%	1.2%	-1.7%	1.0%

Alternate Load Forecasts

In addition to the base case load forecast, the Company developed both higher and lower projections to evaluate resource needs under alternate customer demand conditions. Since the 2021 IRP, the Company has adopted a more robust method for developing these alternate load forecasts. For this IRP, the Company formulated detailed assumptions for high and low load, considering key factors such as economic growth, electric vehicle adoption, behind-the-meter solar adoption, and economic development. Notably, Duke Energy Indiana also incorporated considerable data center load in addition to the larger economic development load assumed in the high load forecast.

Table 3-5 below provides a summary of the assumptions for the low, base, and high forecasts.

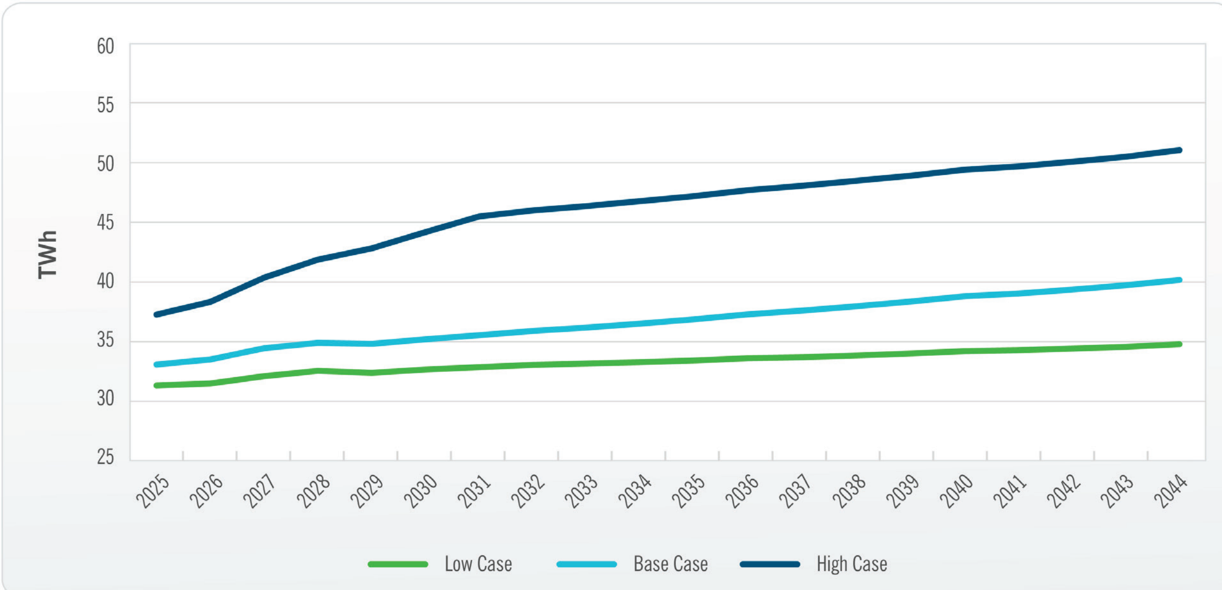
Table 3-5: Key Assumptions for Alternate Load Forecast Scenarios

	Economics	Electric Vehicles	Behind-the-Meter Solar	Economic Development[1]
Low	90/10	Low Adoption	High Adoption	Low (25%)
Base	50/50	Base Adoption	Base Adoption	Base (~60%)
High	10/90	High Adoption	Low Adoption	Higher (75%) +500 MW data center[2]

Note 1: Economic development includes projects greater than 20 MW with plans sufficiently advanced such that some level of demand could be anticipated with a reasonable degree of certainty.
Note 2: 500 MW of data center load is assumed in the high case in addition to 75% of announced economic development projects.

Figure 3-3 below presents the base, low, and high load forecasts used in the IRP. Appendix D provides more details on how each load forecast scenario was developed.

Figure 3-3: System Obligation at Generator for Base, Low, and High Load Forecasts



Fuel Prices

Duke Energy Indiana generates energy to serve its customers using a diverse mix of fuels including coal, syngas, natural gas, and fuel oil, as well as renewable energy resources.

Forecasting Fuel Prices

The Company uses a combination of observable short-term market-based price forecasts and longer-term fundamentals-based price forecasts to develop its coal and natural gas pricing forecasts. The market-based price forecasts incorporate data from third-party market sources along with public exchanges including New York Mercantile Exchange ("NYMEX") and price quotes from fuel providers in response to regular Duke Energy fuel supply requests for proposals. The long-term fundamental forecast is created as a composite of several nationally recognized fuel forecasts including both publicly available data (e.g., United States Energy Information Administration ("EIA")) and third-party proprietary forecasts from multiple reputable fundamental forecast providers.

The Company's high and low fuel price forecasts are based on alternative fuel price cases in the EIA Annual Energy Outlook ("AEO") for 2023. The EIA Low Oil and Gas Supply case describes a future in which fuel supplies are constrained, and high extraction costs are realized, driving up natural gas prices. Conversely, the EIA High Oil and Gas Supply case describes a future with high fuel availability and low extraction costs, which leads to persistently low natural gas prices.

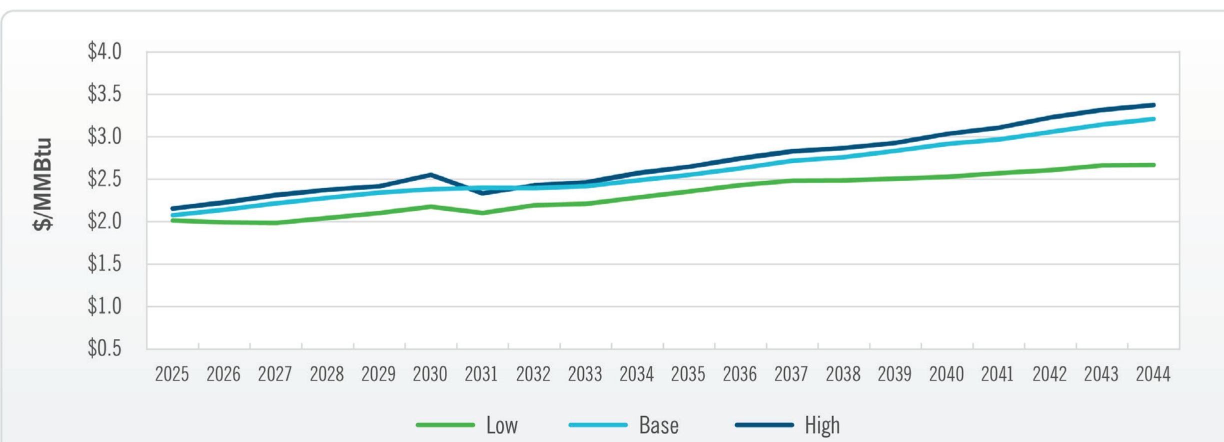
Figures 3-4 and 3-5 below provide the fuel price forecast for coal and natural gas. Additional details on fuel price forecasts can be found in Appendix C.

Coal Procurement & Price Forecasts

Coal-fired generators continue to provide reliable, dispatchable energy to Duke Energy Indiana customers. Until such time that existing coal units are retired or transitioned, coal prices will impact the economics of energy supplied by the fleet. In evaluating the purchase of coal as a fuel, three primary factors are considered: (1) the reliability of supply in quantities sufficient to meet Duke Energy Indiana generating requirements, (2) the quality required to meet environmental regulations and/or manage station operational constraints, and (3) the lowest reasonable cost as compared to other purchase options. The "cost" of the coal includes the purchase price at the delivery point, transportation costs, scrubbing costs for sulfur, emission allowances for nitrogen ("NOx") and sulfur oxides, and the evaluated economic impacts of the coal quality on station operations. Refer to Appendix C to review more detail on cost curves used for the different fuel price forecasts.

To enhance fuel supply reliability and mitigate supply risk, Duke Energy Indiana purchases coal from multiple mines in the geographic area of its stations. Stockpiles of coal are maintained at each station to guard against short-term supply disruptions. Currently, coal supplied to the Company's coal stations is sourced primarily from Indiana and Illinois, as these states are rich in coal reserves with decades of remaining recoverable reserves. However, utility demand for coal is expected to decline over the foreseeable future, which could potentially impact the viability of supply sources over the long term. While coal prices are currently projected to rise only slightly above inflation for much of the planning horizon, the risk of supply shocks increases over time. Annual U.S. coal consumption has fallen over 30% in the last decade in response to coal plant retirements and relatively low natural gas prices. With tens of additional gigawatts ("GW") of capacity potentially retiring across the U.S. in the next decade, utility demand for coal will continue to weaken.[1] Export demand from Asia and Europe are expected to provide some limited upward pressure on thermal coal prices.

Figure 3-4: Coal Price Forecasts (Illinois Basin, $/MMBtu))



[1] U.S. Energy Information Administration, Annual Energy Outlook 2023, March 16, 2023, available at https://www.eia.gov/outlooks/aeo/.

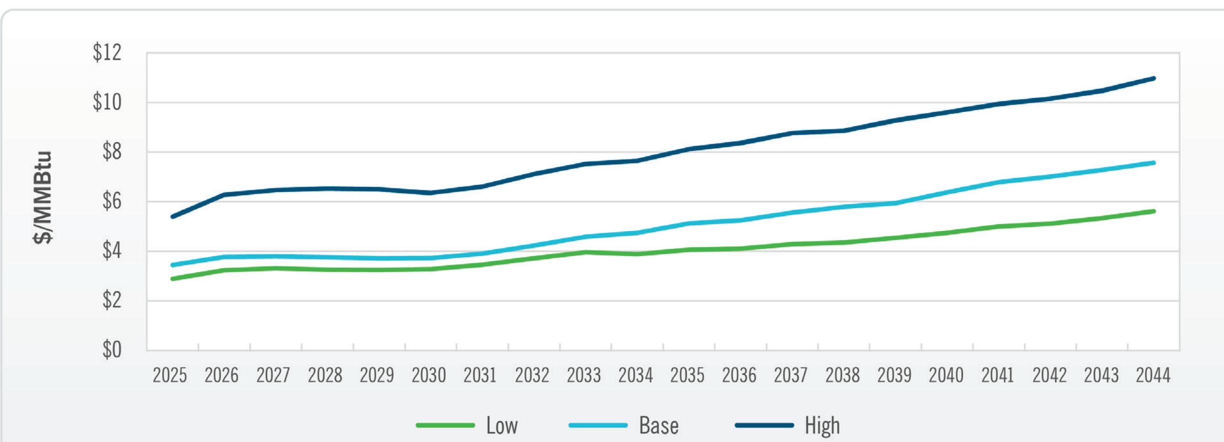
Note: These trend lines are direct outputs of the EIA AEO 2023 High Gas Supply and Oil sensitivity and Low Gas Supply and Oil sensitivity. The High Coal price drops below the Base price due to this dependency on EIA's forecasted gas supply rather than coal supply.

Natural Gas Procurement & Price Forecasts

New natural gas-fired generation will play a critical role in maintaining reliability and affordability for customers as part of an orderly transition to a lower risk, more efficient, and more environmentally sustainable system. Today, Duke Energy Indiana generates nearly a quarter of its electricity from natural gas using combustion turbine ("CT") and combined cycle ("CC") generators. The Company secures firm natural gas supply with spot market purchases under an Asset Management Agreement or under a North American Energy Standards Board agreement as a firm bundled delivered product (spot natural gas plus transportation). The Company releases its firm transportation to an asset manager to optimize and provide supply and firm delivery to its natural gas generation portfolio. Duke Energy Indiana has the following firm transportation contracts: (1) Midwestern Gas pipeline for gas delivery to Edwardsport, Vermillion, and Wheatland; (2) ANR Pipeline for gas delivery to Henry County; and (3) Panhandle Eastern Pipeline for delivery to Noblesville.

For IRP modeling purposes, the Company assumes gas for new resources is delivered via major interstate and intrastate pipelines. The natural gas price forecast includes estimates of the interstate and intrastate firm transportation costs and pipeline upgrades.

Figure 3-5: Natural Gas Price Forecasts (Henry Hub, $/MMBtu)

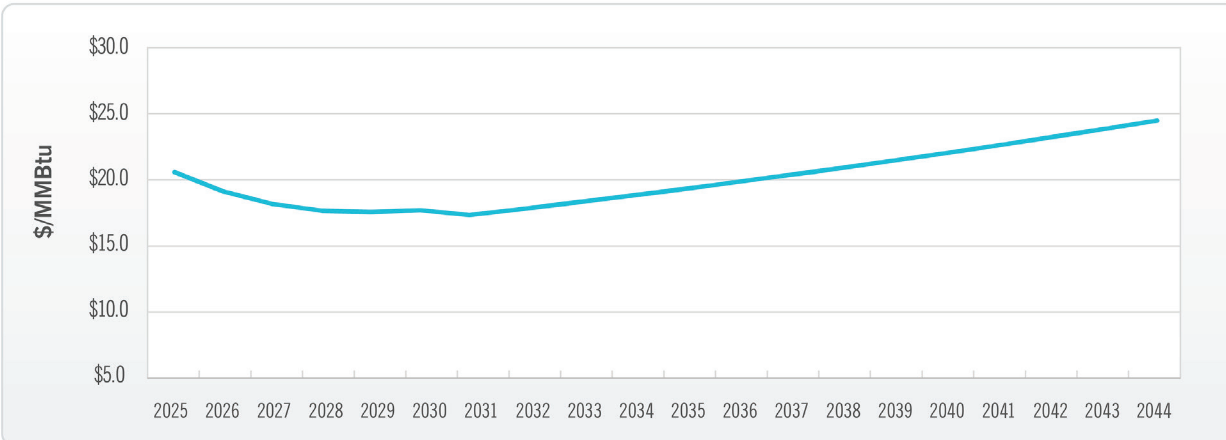


Oil Procurement & Price Forecast

Duke Energy Indiana uses fuel oil to start coal-fired units and for flame stabilization during low load periods. Cayuga Unit 4 (CT) and new CTs use oil as a backup fuel. Oil supplies, purchased on an as-needed basis, are expected to be sufficient to meet needs for the foreseeable future.

As oil makes up less than 0.1% of Duke Energy Indiana's generation mix, only a base price forecast is developed, which is presented in Figure 3-6 below.

Figure 3-6: Oil Price Forecast (NY Harbor Ultra-Low Sulfur Diesel, $/MMBtu)

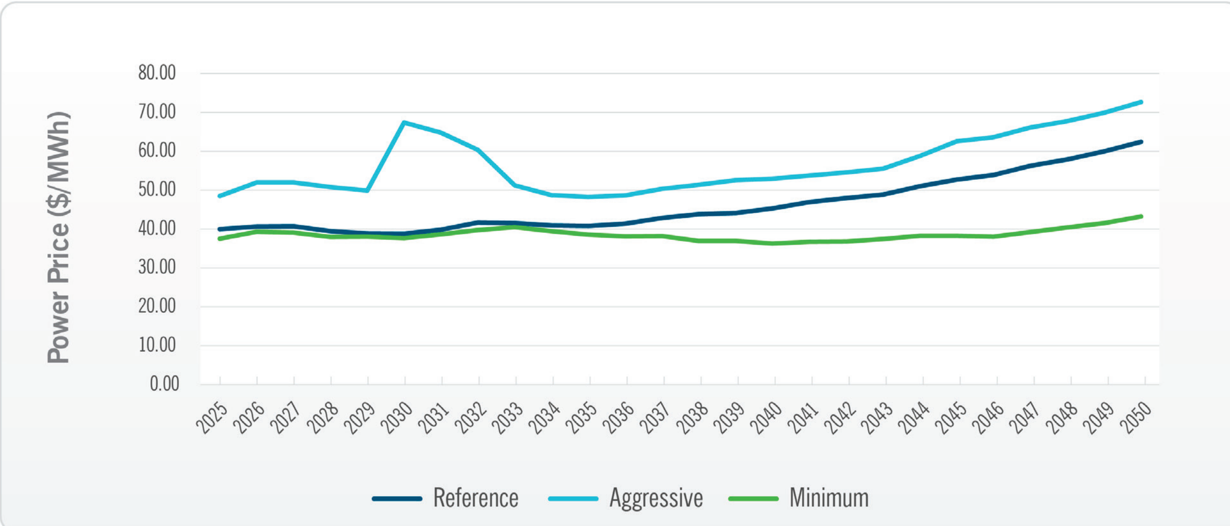


Power Price

Forecasted power prices in the MISO energy market are a function of forecasted fuel prices and other key input assumptions, including requirements under the Environmental Protection Agency ("EPA") Clean Air Act ("CAA") Section 111 May 2024 Final Rule ("EPA CAA Section 111 Rule"), tax incentives under the Inflation Reduction Act of 2022 ("IRA"), potential carbon tax legislation (in the Aggressive Policy & Rapid Innovation Scenario only), and new resource cost and availability. Additionally, changes in MISO's generation fleet are modeled to align with the assumptions of each specific resource planning scenario.

The Company developed individual generation expansion plans for the Eastern Interconnection, which is the power grid reaching from Central Canada eastward to the Atlantic Coast, south to Florida and west to the foot of the Rockies (excluding most of Texas), for each of the three different IRP planning scenarios (or "worldviews"). In addition, the Company also developed unique power price forecasts for the "No 111" portfolio variation, and to align with the high and low fuel price forecasts used in sensitivity analysis. Figure 3-7 below provides the power price forecasts for each planning scenario. The effect of the carbon tax is reflected in the energy price forecast for the Aggressive Scenario starting in 2030. The price increases immediately when the tax is implemented, and then declines rapidly as the market adjusts.

Figure 3-7: Power Price Forecasts by Planning Scenario



Power price forecasts used for sensitivity analysis are provided in Appendix C.

Federal Policy

EPA CAA Section 111 Rule

On May 9, 2024, the EPA published final new source performance standards ("NSPS") for greenhouse gas emissions from new, modified, and reconstructed oil and natural gas-fired electric generating units, as well as emission guidelines for existing coal-fired electric generating units. For new oil and natural gas-fired units, compliance with the NSPS emission limits discussed below are required at commencement of operation, with more stringent limits becoming applicable for new baseload natural gas-fired combustion turbines over time. For existing coal-fired units, under Section 111(d), states must submit plans by 2026 for containing standards consistent with the federal guidelines.

In its final rule, the EPA defines two subcategories for coal-fired units and a retirement option. Long-term coal-fired steam generating units installing and operating carbon capture and sequestration ("CCS") beginning in 2032 with 88.4% reduction from baseline CO_2 emission rates may operate indefinitely. Medium-term coal-fired steam generating units may elect to cease operations before January 1, 2039, and by January 1, 2030, must co-fire 40% natural gas that results in a 16% reduction in emission rate compared to their baseline CO_2 emission rates. Finally, coal units may elect to cease operations before January 1, 2032. In addition, if a coal unit converts to firing 100% natural gas and intends to run past 2039, it must convert by January 1, 2030.

For new baseload natural gas units, the EPA CAA Section 111 Rule requires CCS by January 1, 2032; however, Duke Energy Indiana does not expect CCS to be a viable alternative in that time frame due to the state of existing technology. (One potential exception is Edwardsport, where the Company has been awarded a U.S. Department of Energy front-end engineering and design ("FEED") study for CCS demonstration.) As such, starting January 1, 2032, new baseload natural gas units are limited to the requirements for intermediate load units, that is, a 40% annual capacity factor ("CF") limitation. New CTs treated as intermediate load units and are also limited to a 40% capacity factor in the modeling in compliance with the new rule.

Figure 3-8 below provides a summary of the EPA CAA Section 111 Rule for existing coal units and new natural gas turbines. These new requirements will impact coal units at Cayuga, Gibson, and Edwardsport and will be implemented as part of a State Plan submitted by the Indiana Department of Environmental Management ("IDEM") to EPA for its approval.

Figure 3-8: Summary of Compliance Options Under EPA CAA Section 111 Rule

	Existing Coal			
Deadline	Retire	Co-fire	Convert	CCS
1/1/2030		40% natural gas co-firing (at least 16% emissions reduction)	Conversion to 100% natural gas	
1/1/2032	Retire without changes			Presumptive 88.4% CO_2 emission rate reduction, equivalent to 90% CCS installed and operational
12/31/2038		Retire		Can continue to operate on gas or on coal with CCS

	New Gas Turbines		
Deadline	Base Load (>40% CF)	Intermediate Load (20% < CF ≤ 40%)	Low Load (≤20% CF)
Upon operation	800 lb. CO_2/MWh	1,170 lb. CO_2/MWh	Use of lower-emitting fuels (<160 lb. CO_2/MMBtu)
1/1/2032	Emission rate of 100 lb. CO_2/MWh, equivalent to 90% CCS installed and operational		

Additional information about the EPA CAA Section 111 Rule and the other environmental rules and regulations impacting the resource plan modeling can be found in Appendix J (Environmental Compliance).

Clean Water Act Section 316(a) & 316(b)

In compliance with Sections 316(a) and 316(b) of the Clean Water Act, Duke Energy Indiana has submitted study reports to IDEM ensuring compliance of existing identified thermal resources, which include Cayuga, Gibson, and Noblesville. No further action is needed at Gibson and Noblesville for those units to be in compliance with Section 316(a) and 316(b), at this time; however, continued operation of the Cayuga steam units into the mid-2030s would be complicated by the need to potentially add closed-cycle cooling to achieve compliance with Section 316 requirements. These requirements are discussed further in Appendix J.

Carbon Tax

In the Aggressive Policy & Rapid Innovation (“Aggressive”) scenario only, Duke Energy Indiana included a carbon tax introduced by 2030. This scenario assumes aggressive climate policy intervention implemented through a combination of incentives, taxes and regulations. The carbon tax assumption is informed by the Market Choice Act (“MCA”) reintroduced in the 118th Congress, which proposed a carbon tax of $35 per metric ton of CO_2 equivalent emissions.

In the Reference and Minimum Policy & Lagging Innovation (“Minimum”) scenarios, Duke Energy Indiana did not model a tax on carbon emissions. Currently, there are no state or federal regulations taxing carbon emissions.

Inflation Reduction Act

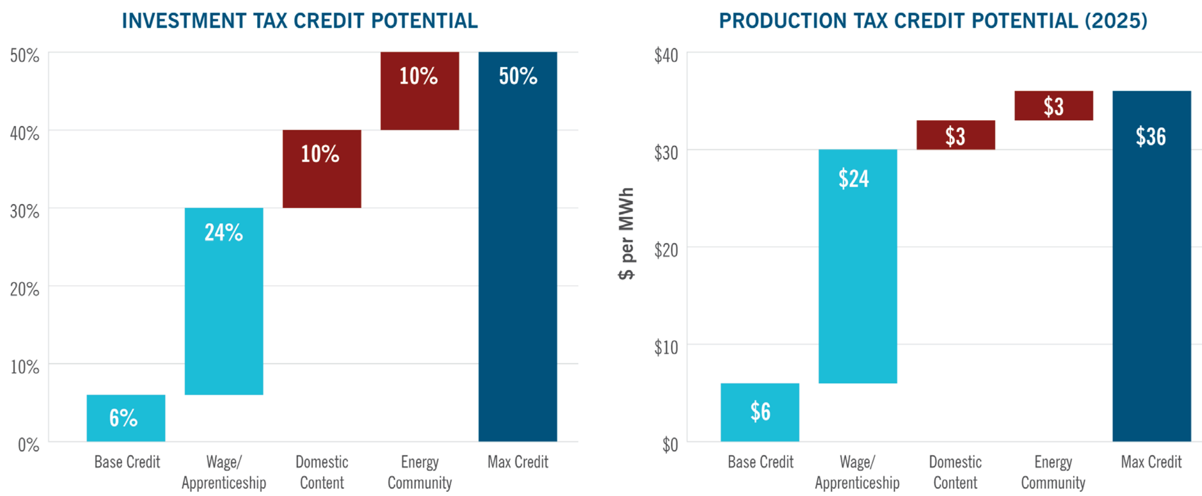
The Inflation Reduction Act of 2022 was signed into law on August 16, 2022. For Duke Energy Indiana, the IRA will primarily provide production tax credits (“PTC”) and investment tax credits (“ITC”) for zero-carbon generation. PTCs are inflation-adjusted federal tax credits for each kilowatt-hour (“kWh”) of electricity generated during the first 10 years of a facility’s operation. ITCs are federal tax credits based on a percentage of the capital cost of a facility and can be taken immediately upon project completion.

Both the ITC and PTC are awarded in base and bonus amounts as certain criteria are met. As seen in *indicative* Figure 3-9 below, the base credit for building a zero-carbon emitting resource is 6% of eligible investment for ITC and $6/megawatt-hour (“MWh”) (2025$) of PTC for the first 10 years of operation (inflating over time). There are three types of bonuses that can be added by meeting certain criteria for projects greater than 5 MW: (1) Wage and Apprenticeship (“W&A”), (2) Domestic Content, and (3) Energy Communities. These criteria are subject to certain conditions:

- Wage & Apprenticeship: Project wages must be equal to or greater than local prevailing wages; certain percentage of work hours must be performed by qualified apprentices.
- Domestic Content: Project's iron, steel and other components must be made in the U.S., and a certain percentage of the project’s manufactured products must be produced in the U.S.
- Energy Community: Project must be located in a coal closure area, a brownfield area, or other statistical area identified by the U.S. Internal Revenue Service.

Meeting wage and apprenticeship criteria adds a five times multiplier on the base credit, which results in a base ITC increase by 24 percentage points to a total of 30% and an increase in base PTC by $24/MWh to a total of $30/MWh. Meeting domestic content or energy community criteria can increase ITC by 10 percentage points each or 20 percentage points combined and PTC by $3/MWh each or $6/MWh combined. Potential maximum credit if all bonus criteria is met is 50% for ITC and $36/MWh (2025$) for PTC.

Figure 3-9: IRA ITC & PTC Potential



The Company assumes in the 2024 IRP analysis it will be able to meet wage and apprenticeship guidelines for all zero-carbon technologies. The baseline tax credits for all eligible projects will be approximately 30% ITC or $30/MWh PTC (2025). The Company also assumes it will achieve the domestic content bonus for wind projects beginning in 2030, energy community bonuses for 60% of standalone solar and solar paired with storage (“SPS”), and energy community bonuses for 100% of standalone battery energy storage and advanced nuclear (small modular reactor (“SMR”) and advanced reactor (“AR”)).

Table 3-6 below provides an overview of ITC and PTC assumptions for each technology type, including where applicable bonus incentives are included. For generic IRP modeling purposes, the Company assumes that solar and wind will receive PTCs, and all advanced nuclear and energy storage, whether paired or standalone, will receive ITCs. Nuclear units are modeled at a 40% ITC value with 10% cost of transfer – equating to 36% final ITC. Actual tax credit determinations will be made on a project-by-project basis in plan execution, based on-site and project-specific criteria.

Table 3-6: IRA Assumptions in Reference Scenario

	Base PTC (45Y)	Base ITC (48E)	Bonus Wage & Apprent.	Bonus Energy Comm	Bonus Domestic Content	PTC Modeling	ITC Modeling
SMR	No	Yes	Yes	100%	No	N/A	36% ITC
Standalone Solar	Yes	No	Yes	60%	No	1.06x W&A PTC	N/A
Wind (Pre-2030)	Yes	No	Yes	60%	No	1.06x W&A PTC	N/A
Wind (2030+)	Yes	No	Yes	60%	Yes	1.16x W&A PTC	N/A
SPS (Solar)	Yes	No	Yes	60%	No	1.06x W&A PTC	N/A
SPS (Storage)	No	Yes	Yes	60%	No	N/A	36% ITC
AR (Nuclear)	No	Yes	Yes	100%	No	N/A	36% ITC
AR (Storage)	No	Yes	Yes	100%	No	N/A	36% ITC
Standalone Storage	No	Yes	Yes	100%	No	N/A	40% ITC

Tax credits are also available for CCS at a rate of \$85/metric ton of CO_2 captured and sequestered for the first 12 years of CCS system operation.

Table 3-7: IRA Incentives Modeled for CCS

	Incentive	Bonus Wage & App	Tax Credit Description	Phase Out
CCS	45Q	Yes	12 Years of Tax Credits @ \$85/Metric Ton of CO_2 Captured & Sequestered	Construction Must Begin by 12/31/32; Safe Harbor available

Tables 3-6 and 3-7 above present the IRA assumptions used for the Reference Case. As detailed in Chapter 2 (Methodology), the Company adjusted IRA assumptions for the Aggressive and Minimum worldviews. Like the Reference Scenario, the Aggressive Worldview assumes an extension of PTCs and ITCs over the planning period (no phaseout); however, the Aggressive Worldview includes additional domestic content bonuses for solar, wind, and solar paired with storage, boosting the applicable PTC or ITC credits, as summarized below in Table 3-8. The Minimum Worldview assumes the IRA is repealed by 2025; therefore, no PTCs and ITCs are included in modeling for that scenario.

Table 3-8: IRA Assumptions in Aggressive Worldview

	Base PTC (45Y)	Base ITC (48E)	Bonus Wage & Apprent.	Bonus Energy Community	Bonus Domestic Content	PTC Modeling	ITC Modeling
SMR	No	Yes	Yes	100%	No	N/A	36% ITC
Standalone Solar	Yes	No	Yes	60%	Yes	1.16xW&A PTC	N/A
Wind	Yes	No	Yes	60%	Yes	1.16xW&A PTC	N/A
SPS (Solar)	Yes	No	Yes	100%	Yes	1.16xW&A PTC	N/A
SPS (Storage)	No	Yes	Yes	Yes	No	N/A	36% ITC
AR (Nuclear)	No	Yes	Yes	100%	No	N/A	36% ITC
AR (Storage)	No	Yes	Yes	100%	No	N/A	36% ITC
Standalone Storage	No	Yes	Yes	Yes	No	N/A	40% ITC

Supply-Side Resources

This section provides brief descriptions, model inputs, and assumptions for supply-side resources included in the 2024 IRP analytics. To be selectable in the capacity expansion model, each resource type discussed here passed the technical and economic screening process described in Appendix F (Supply-Side Resources). Appendix F also includes information on resources excluded from IRP analysis due to technical or economic screening.

For IRP modeling purposes, new generic resources are treated as if they are Company-owned in order to ensure that differing ownership structures do not distort resource evaluation within the EnCompass capacity expansion model. The role of the IRP is to identify how much of and when each resource type should be added to or removed from the portfolio. Specifics of how resources are procured, including appropriate contractual or other arrangements, are project-specific considerations that are determined in resource procurement, downstream of the IRP.

Retirement & Conversion of Existing Resources

As introduced in Chapter 2, the Company developed the various generation strategies to evaluate combinations of retirements and conversions of existing coal units to achieve compliance with the EPA CAA Section 111 Rule. In addition to the 111-compliant strategies, Duke Energy Indiana developed a “No 111” strategy variation using the Reference Case inputs absent the requirements of the EPA CAA Section 111 Rule. The full analytical framework for the 2024 IRP, including the generation strategies, strategy variations, and sensitivity analysis, is described in detail in Chapter 2.

Selectable Supply-Side Resources

The Company considered a diverse range of baseload, intermediate, peaking, variable energy, and energy storage technologies in developing the Plan. Appendix F describes the technical and economic screening process the Company used to identify the technically and economically viable resources for inclusion in IRP modeling. This section provides an overview of the assumptions associated with the selectable supply-side resources made available in the EnCompass capacity expansion modeling phase.

Table 3-9 below summarizes the key Reference Scenario assumptions for selectable supply-side resources included in the capacity expansion modeling. Further details regarding model input assumptions for selectable resources are provided in this section, with additional information provided in appendices referenced herein. As previously noted, input assumptions, such as project capital costs and transmission interconnection costs for each resource type, are generic values, and actual costs and characteristics will vary by project according to site and project-specific conditions. As part of the generic modeling process, several resource types were available for model selection in capacity blocks smaller than what may actually be deployed. This was done to better understand how the timing of resource needs is distributed and to reflect the ability to partner with other entities on new generating stations.

Table 3-9: Key Assumptions for Selectable Supply-Side Resources in Reference Case

Technology	Key Assumptions
Solar	• 300 MW available for model selection in 2027, 1,150 MW in 2028, 1,400 MW in 2029, 1,600 MW/year in 2030 and 2031, and 1,800 MW/year from 2032 through the end of the planning period • Bifacial panels, single-axis tracking (“SAT”) • Beginning in 2028, model may select standalone solar or solar paired with 4-hour battery energy storage
Storage Paired with Solar	• 575 MW available for model selection in 2028, 700 MW in 2029, 800 MW/year in 2030 and 2031, and 900 MW/year from 2032 through the end of the planning period • Capacity for paired storage resources is equal to 50% of the associated AC solar capacity • 4-hour lithium-ion
Standalone Storage	• Up to 300 MW/year available for model selection in 2028 and 2029, increasing to 700 MW/year from 2030 through the end of the planning period • All storage available in the Reference Scenario is 4-hour lithium-ion

Advanced Nuclear	• Four 300 MW SMRs available for model selection in 2037 and each year thereafter (1,200 MW/year) • Two 300 MW advanced reactors with 150 MW of integrated thermal energy storage available beginning 2039 (900 MW/year)
Wind	• 200 MW/year available for model selection in 2028 and 2029, 300 MW/year in 2030 and 2031, 400 MW/year available from 2032 through the end of the planning period
Gas	• Market-based natural gas commodity prices are used for 2025-2029, transition from market-based to fundamentals-based prices 2030-2032, full fundamentals-based pricing beginning in 2033 • One 1x1 CC (719 MW) available per year 2030-2032, three 1x1 CCs available each year 2033-2037, up to a cumulative total of six units • Two 2x1 CCs (1,438 MW each) available in 2032 only, to evaluate alternate configurations • One 2x1 CC with carbon capture and sequestration (1,215 MW) available per year starting in 2035, eligible for IRA 45Q tax credits if selected before 2040 • Two CTs available per year (425 MW each) from 2031-2037

In addition to the physical supply-side resources listed in the table above, the Company also allowed the model to select a generic, capacity-only resource in the early part of the planning period prior to the availability of new resources. This generic capacity resource has a one-year life and is a proxy for potential bilateral contracts or other potential near-term capacity resources. The cost of this resource for modeling purposes is based on the $720/MW-day clearing price for Zone 5 spring and fall capacity in the 2024/2025 MISO Planning Resource Auction (Zone 5 had highest clearing price).

Reference Case Modeling Inputs & Assumptions for Supply-Side Resources

This section includes descriptions of the costs, resource characteristics, and resource availability assumptions that Duke Energy Indiana used in the 2024 IRP analysis. The Company conducted capacity expansion modeling using beginning-of-year ("BOY") convention, meaning that resource changes (new unit additions, unit retirements and contract expirations, unit conversions) occur on January 1st of each year for modeling purposes. The information provided here is presented on a BOY basis.

Duke Energy Indiana considers a variety of data sources when preparing cost forecasts for each technology type, the details of which are provided in Appendix F. In addition to third-party estimates and the Company's own experience and expertise, Duke Energy Indiana used information from its ongoing 2023/2024 All-Source Request for Proposal ("RFP") to benchmark generic unit cost and resource availability assumptions.

The overnight costs shown herein are rounded to the nearest $50/kW and include a generic interconnection adder, expected owner's costs, and a contingency factor. Costs are presented in terms of dollars per kW of installed capacity. Expressed in 2024 dollars, these costs represent the estimated overnight cost for projects begun in 2024, with in-service dates aligning with generic project lead times for each resource type. Overnight costs for future in-service years are projected using technology-specific inflation curves based on an assumed general inflation rate and the expected technology learning curve through the modeling period.

Solar & Solar Paired with Storage

Technology Description

The generic solar unit in the 2024 IRP is a 50 MW-AC single-axis tracking system using bifacial panels. The generic solar facility has a 25% capacity factor. Duke Energy Indiana also modeled a generic solar resource paired with battery energy storage. For this resource, the battery component may be charged directly from the grid. Table 3-10 below summarizes the solar and solar paired with storage configurations available for model selection.

Table 3-10: Resource Characteristics of Solar and Solar Paired with Battery Storage

Technology	Model Inputs
Solar Capacity	50 MW inverter AC capacity (70 MW maximum DC capacity)
Paired Storage Power Capacity / Duration	25 MW (50% of solar MW-AC) / 4 hours
Paired Storage Energy Capacity	100 MWh

Technology Cost

The generic overnight costs for solar and solar paired with storage are provided in Table 3-11 below. These Midwest-specific cost estimates are based on information provided in Guidehouse cost forecasting tools[2] and benchmarked against the Company's ongoing RFP and other industry sources.

Table 3-11: Overnight Capital Costs of Solar and Solar Paired with Storage

Technology	Overnight Cost (2024 $/kW)
Solar PV, Bifacial SAT	$1,850
Solar PV Bifacial SAT + Li-ion Storage	$2,950

[2] Guidehouse creates cost forecasting tools based on market estimates of the technologies to determine current installation costs as well as expected costs for the next 10 years for each technology. The costs are validated against other industry reports and engineering studies.

Resource Availability

Table 3-12 below shows the resource availability assumptions for solar in the Reference Case. Beginning in 2028, the model may select either standalone solar or solar paired with storage.

Table 3-12: Availability of Solar and Solar Paired with Storage Resources

Technology	2027	2028	2029	2030-2031	2032+
Solar[1]	300 MW	1,150 MW	1,400 MW	1,600 MW/yr	1,800 MW/yr
Paired Storage[2]	–	575 MW	700 MW	800 MW/yr	900 MW/yr

Note 1: Solar resource availability includes standalone solar and solar paired with battery storage.
Note 2: Storage resource availability includes battery storage paired with solar. Standalone battery storage availability is provided below.

Standalone Energy Storage

Technology Description

Energy storage is used to transfer energy in time from when it is generated to when it is needed to serve customers. This service becomes increasingly important as weather-dependent resources grow as a share of the MISO system. In addition, fast-responding energy storage may support grid stability as more coal resources are projected to retire over the next decade.

Table 3-13 below provides the configuration of standalone battery energy storage modeled in the 2024 IRP.

Table 3-13: Resource Characteristics of Standalone Li-ion Battery Energy Storage

Technology	Model Inputs
Storage Power Capacity	50 MW
Storage Energy Capacity	200 MWh
Full Load Discharge Duration	4 hours

Technology Cost

The overnight capital cost estimate for energy storage is provided in Table 3-14 below. Battery energy storage costs were based on estimates from the Guidehouse tool.

Table 3-14: Overnight Capital Cost of Standalone Battery Energy Storage

Technology	Overnight Cost (2024 $/kW)
4-hour Li-ion Storage	$2,300

Resource Availability

Table 3-15 below shows the resource availability assumptions for standalone storage used in the Reference Case.

Table 3-15: Availability of Standalone Battery Energy Storage Resources

Technology	2028-2029	2030+
4-hour Li-ion Storage	300 MW/yr	700 MW/yr

Long-Duration Energy Storage Available in Aggressive Policy & Rapid Innovation Scenario

In addition to the 4-hour Li-ion battery energy storage available in all scenarios, the Aggressive Scenario includes long-duration energy storage ("LDES") options for model selection. The Company developed the overnight cost forecasts for the LDES proxies using a variety of sources, including publicly available resources and vendor solicitations. The public sources included the Department of Energy's LDES Commercial Liftoff Report and the LDES Council's "Net-Zero Power Long Duration Energy Storage for a Renewable Grid" report. The publicly available data often includes only the direct cost of the energy storage and does not account for total installed costs. Therefore, the Company applied adders for costs such as owner's cost where appropriate. Table 3-16 below presents the LDES costs modeled in the Aggressive Scenario.

Table 3-16: Overnight Capital Cost of Long-Duration Energy Storage

Technology	Overnight Cost (2024 $/kW)
10-Hour Generic LDES	$2,300
100-Hour Generic LDES	$2,550

Although LDES is still maturing, the Aggressive Scenario assumes a rapid timeline for innovation and commercial availability of emerging technologies, allowing LDES to be available for model selection by the early 2030s as shown in Table 3-17 below.

Table 3-17: Availability of Long-Duration Energy Storage Resources in the Aggressive Policy & Rapid Innovation Scenario

Technology	2030−2031	2032+
10-Hour Generic LDES[1,2]	500 MW/yr	500 MW/yr
100-Hour Generic LDES[1,2]	–	100 MW/yr

Note 1: LDES is a selectable resource in the Aggressive Policy & Rapid Innovation scenario only.
Note 2: No more than 500 MW total LDES (10-hour and 100-hour combined) can be selected per year.

Advanced Nuclear

Technology Description

Next generation nuclear can provide significant operational flexibility that will be needed to support the increased deployment of renewable energy resources. As shown in Table 3-18 below, the Company considered two types of advanced nuclear plants in development of the 2024 IRP: small modular reactors and advanced reactors. SMRs are water-cooled reactors, while ARs are non-water-cooled (e.g., molten salt, liquid metal, or high-temperature gas).

Table 3-18: Summary Resource Characteristics of Advanced Nuclear Technologies

Advanced Nuclear	
Small Modular Reactor	• Light water-cooled (the same technology utilized by today's current commercial fleet) • Proven technology and furthest along from a licensing standpoint • Typically, 300 megawatts electric ("MWe") or less
Advanced Reactor	• Non-water-cooled – uses molten salt, helium gas or liquid sodium • Higher efficiency, cycling ability and integrated storage • Integrates well with variable renewable power • Can be 50 MWe up to 1,200 MWe; typically, 350 MWe or less

Technology Cost

The projected overnight costs of advanced nuclear reactors are provided in Table 3-19 below. Advanced nuclear reactor costs are based on Electric Power Research Institute ("EPRI") analysis and reports, information from vendors, and other engineering studies.

Advanced nuclear technologies, particularly SMRs, offer several potential cost advantages over traditional nuclear power plants. By fabricating modular sections and equipment rooms offsite, the need for concrete, rebar, and on-site welding is significantly reduced. This off-site construction approach, combined with the use of commercially available components and fewer moving parts, leads to a smaller site footprint and lower costs relative to traditional nuclear. Additionally, the proven reactor technology and passive safety features of SMRs are expected to reduce licensing costs. As designs and construction processes continue to improve, the costs associated with advanced nuclear technologies are anticipated to decline further.

Table 3-19: Overnight Capital Cost of Advanced Nuclear Reactors

Technology	Overnight Cost (2024 $/kW)
Small Modular Reactor	$11,150
Advanced Reactor with Thermal Storage	$12,300

Resource Availability

In the Reference Scenario, the Company assumes that the first four 300 MW SMR blocks will be available beginning in 2037, with an additional four 300 MW blocks available each year thereafter. In addition, two 300 MW AR blocks (paired with 150 MW thermal storage) are available for model selection beginning in 2039 and each year thereafter, as shown in Table 3-20 below.

Table 3-20: Availability of Advanced Nuclear Resources

Technology	2037-2038	2039+
SMR (300 MW/block)	1,200 MW/yr	1,200 MW/yr
AR (300 MW nuclear and 150 MW thermal storage/block)	–	900 MW/yr (600 MW nuclear, 300 MW storage)

Onshore Wind

Technology Description

Onshore wind technology is a mature and scalable zero-carbon resource. Similar to solar, wind is a variable energy resource with output dependent on weather conditions.

Technology Cost

The overnight cost for wind resources is provided in Table 3-21 below. Wind technology costs are based on estimates from the Guidehouse tool specific to the Midwest.

Table 3-21: Overnight Capital Cost of Onshore Wind

Technology	Overnight Cost (2024 $/kW)
Onshore Wind	$2,050

Resource Availability

Table 3-22 below shows the wind resource availability assumptions used in Reference Case modeling.

Table 3-22: Availability of Onshore Wind Resources

Technology	2028-2029	2030-2031	2032+
Onshore Wind	200 MW/yr	300 MW/yr	400 MW/yr

Simple Cycle Combustion Turbines & Combined Cycle Power Blocks

Technology Description

Highly efficient advanced class combustion turbines, whether in simple cycle CT configuration or in CC power blocks, will play a critical role into the future, meeting the growing need for flexible, dispatchable resources that are capable of operating for extended periods of time. Reliable, dispatchable resources are required to support and backstop the integration of increasing amounts of variable-energy renewable resources and to maintain reliability as the Company transitions away from aging coal units. Although new gas-fired resources are limited to a 40% capacity factor under the EPA CAA Section 111 Rule, they will continue to provide low-cost energy up to the regulatory limits and be essential to maintaining system reliability and stability over the coming decades. The Company considered the scale, complexity, and lead times of new CC projects in determining the amount of new CC capacity available for model selection as seen in Table 3-23 below.

Table 3-23: Resource Characteristics of CCs and CTs

Technology	Capacity per Unit
1x1 Advanced Class Combined Cycle	719 MW
2x1 Advanced Class Combined Cycle	1,438 MW
2x1 Advanced Class Combined Cycle with CCS	1,215 MW
Advanced Class Combustion Turbine	425 MW
Hydrogen-Fueled Advanced Class CT	425 MW

Technology Cost

Overnight cost ranges for CTs and CCs are provided in Table 3-24 below. CT and CC costs are presented as a range, as they are based on proprietary data for specific turbine configurations for the Midwest region.

Table 3-24: Overnight Capital Costs of CCs and CTs

Technology	Overnight Cost (2024 $/kW)
1x1 Advanced Class Combined Cycle	$1,450-$1,550
2x1 Advanced Class Combined Cycle	$1,100-$1,250
2x1 Advanced Class Combined Cycle with CCS	$3,750
Multi-Unit Advanced Class Combustion Turbine	$1,000-$1,200
Hydrogen-Fueled Advanced Class CT	$1,200-$1,450

Resource Availability

- Combined cycles are available for model selection beginning in 2030. One 1x1 unit (719 MW) is available each year from 2030 to 2032, and three units are available each year from 2033 to 2037, up to a cumulative total of six 1x1 CC units as seen in Table 3-25 below.
- Two 2x1 CCs (1,438 MW each) are available in 2032 only, to allow evaluation of alternate CC configurations coinciding with coal unit retirements in compliance with the EPA CAA Section 111 Rule. Ultimately, the specific unit configuration will be determined in plan execution based on total system needs and project and site-specific considerations.
- One 2x1 CC with CCS (1,215 MW) is available for model selection each year beginning in 2035, up to a cumulative total of two. This technology is eligible for IRA 45Q tax credits if added before 2040.
- Two advanced class simple cycle CTs (425 MW each) are available per year, from 2031 to 2037 up to a cumulative total of four CTs. CTs are available for selection in half units as seen in table 3-26 below.
- In the Aggressive Worldview, two hydrogen-fueled advanced class simple cycle CTs (425 MW each) are available per year, beginning in 2031, up to a cumulative total of four hydrogen CTs. Hydrogen CTs are available for selection in half units.

To provide the capacity expansion model a range of different CC configuration options to replace retiring coal units, the Company made both 1x1 and 2x1 CCs available for selection in 2032. This resulted in the model being allowed to select more CC capacity in 2032 than may be prudent to attempt to deploy in a single year. Plan executability is evaluated in the selection of a Preferred Portfolio and is reflected on the scorecard. Execution considerations are further addressed in the Short-Term Action Plan, where generic model assumptions are translated to real world, executable actions.

Table 3-25: Availability of Combined Cycle Generators

Combined Cycle					
Technology	**2030-2031**	**2032**	**2033-2034**	**2035-2037**	**2038+**
1x1 CC	719 MW/yr	719 MW	2,157 MW/yr	2,157 MW/yr	–
2x1 CC	–	2,876 MW	–	–	–
2x1 CC with CCS	–	–	–	1,215 MW/yr	1,215 MW/yr

Table 3-26: Availability of Combustion Turbine Generators

Combustion Turbine		
Technology	**2031-2037**	**2038+**
CT	850 MW/yr	–
Hydrogen CT[1]	850 MW/yr	850 MW/yr

Note 1: Hydrogen CT is a selectable resource in the Aggressive Policy & Rapid Innovation scenario only.

Appendix F provides additional discussion of CC and CT technologies.

Transmission Network Upgrade Cost

The Company applied a generic transmission network upgrade cost proxy of $0.275/w (2024$) which equates to a $20.872/kW-year levelized cost to new resources modeled in the 2024 IRP. The estimate was based on historical network upgrade requirements for projects in the MISO generator interconnection queue. This generic proxy is added to all renewable, battery energy storage, and thermal resources except for CC resources available for selection by 2032. For modeling purposes, the Company assumes that new CC and CT capacity added in this timeframe will be eligible for generator replacement in the MISO interconnection process and likely not require transmission network upgrades.

Resource Availability Assumptions for Alternate Worldviews

Tables 3-27 and 3-28 below provide the Company's resource availability assumptions used in the Aggressive Policy & Rapid Innovation and Minimum Policy & Lagging Innovation worldviews as compared to the Reference Case. Assumptions differing from the Reference Case are indicated in bold text. Assumptions matching that of the Reference Case are denoted as "Reference."

Duke Energy Indiana presented its preliminary resource availability assumptions to stakeholders in the second series of technical and public stakeholder meetings in April 2024. Stakeholders found the assumptions overly conservative and suggested that the Company further consider resource availability assumptions for renewables so as to not unduly constrain the capacity expansion model. Duke Energy Indiana worked with internal subject matter experts to thoughtfully review assumptions and contemplated potential developments that might enable deployment of larger amounts of solar and wind in the time frames under consideration in the IRP. The Company adjusted renewable resource availability based on assumptions of streamlining to MISO's Definitive Planning Phase process and interconnection queue reforms that could result in expedited study processes, thereby increasing the rate at which new renewable resources can be brought online. Based on these assumptions, the Company (1) increased Reference Case solar availability from 1,000 MW/year to 1,200 MW/year beginning in 2032, (2) increased availability of wind beginning in 2032 from 300 MW/year to 400 MW/year in the Reference Case, and (3) increased wind availability from 600 MW/year to 1,000 MW/year in the Aggressive Case.

Table 3-27: Availability of Thermal Resources Across Worldviews

Resource Type	Aggressive Policy & Rapid Innovation	Reference	Minimum Policy & Lagging Innovation
Natural Gas CT (425 MW/unit)	Reference	2031-2037: 850 MW/yr	Reference
Hydrogen CT (425 MW/unit)	**2031+: 850 MW/yr**	Not Available	Reference
1x1 CC (719 MW/unit)	Reference	2030-2032: 719 MW/yr 2033-2037: 2,157 MW/yr	Reference
2x1 CC (1,438 MW/unit)	Reference	2032: 2,876 MW	Reference
2x1 CC w/ CCS (1,215 MW/unit)	Reference	2035+: 1,215 MW/yr	Reference
SMR – Advanced Nuclear (300 MW/unit)	Reference	2037+: 1,200 MW/yr	**Not Available**
AR – Advanced Nuclear (300 MW AR & 150 MW storage/unit)	Reference	2039+: 900 MW/yr	**Not Available**

Table 3-28: Availability of Renewables & Storage Resources Across Worldviews

Resource Type	Aggressive Policy & Rapid Innovation	Reference	Minimum Policy & Lagging Innovation
Solar[1]	2027: 300 MW	2027: 300 MW	Reference
	2028: 1,150 MW	2028:1,150 MW	
	2029: 1,900 MW	2029: 1,400 MW	
	2030–2031: 2,500 MW/yr	2030-2031: 1,600 MW/yr	
	2032+: 2,500 MW/yr	2032+: 1,800 MW/yr	
Wind	2028–2029: 200 MW/yr	2028-2029: 200 MW/yr	Reference
	2030–2031: 600 MW/yr	2030-2031: 300 MW/yr	
	2032+: 1,000 MW/yr	2032+: 400 MW/yr	
4-hour Storage[2]	2028: 875 MW	2028: 875 MW	Reference
	2029: 1,250 MW	2029: 1,000 MW	
	2030-2031: 2,450 MW/yr	2030-2031: 1,500 MW/yr	
	2032+: 2,450 MW/yr	2032+: 1,600 MW/yr	
10-hour LDES[3]	**2030+: 500 MW/yr**	Not Available	Reference
100-hour LDES[3]	**2032+: 100 MW/yr**	Not Available	Reference

Note 1: Solar resource availability includes standalone solar and solar paired with battery storage.
Note 2: 4-hour storage resource availability includes standalone battery storage and battery storage paired with solar.
Note 3: No more than 500 MW total LDES (10-hour and 100-hour combined) can be selected per year.

Conversion of Existing Units & Associated Maintenance Requirements

Under EPA CAA Section 111 Rule, Duke Energy Indiana has the option to convert existing coal-fired units to either (1) 100% natural gas, or (2) 50% co-fired with natural gas. Either option allows the existing coal-fired units, Cayuga and Gibson, to continue operating longer than previously anticipated. In doing so, certain additional maintenance projects must be completed to allow these units to operate into the late 2030s or beyond. These projects include multiple plant infrastructure projects; steam condenser/turbine/generator projects; auxiliary boilers, valve and fan damper replacements; supplemental cooling tower work; spare transformers; and structural support work.

Demand-Side Resources

Duke Energy Indiana's 2024 IRP incorporates contributions from demand-side resources including energy efficiency ("EE"), demand response ("DR"), Integrated Volt/Var Control ("IVVC"), and other customer programs. The Company's customer programs provide valuable capacity and energy through managing customer load and shifting demand away from times of peak, as in the case of demand response and certain pricing measures, or by reducing overall energy consumption as in the case of UEE programs. Duke Energy Indiana retained Resource Innovations to conduct a Market Potential Study ("MPS") for demand-side resources to inform the 2024 IRP analysis. More details on the MPS and how it was used in IRP analytics can be found in Appendix H. The MPS report itself has also been provided together with the IRP as Attachment H-1.

Energy Efficiency

Duke Energy Indiana's EE programs support customers to reduce their energy usage, which can help to reduce their electricity bills. The Company provides several residential and non-residential EE programs to its customers, such as Smart $aver® Residential, Neighborhood Energy Saver Program, and Business Energy Saver, to name a few.

Duke Energy Indiana worked collaboratively with Resource Innovations and stakeholders on evaluating energy efficiency in the MPS, which included multiple scenarios for future energy savings potential. Projected impacts from EE programs were developed in the MPS and included as selectable resources in modeling for the 2024 IRP.

In preparing for projected demand-side resource options available for selection in the 2024 IRP, the Company developed sub-portfolios of UEE programs (also referred to as "bundles"). These bundles were designed to be treated similarly to supply-side resources for selection by the EnCompass capacity expansion model. Bundles were made available starting in 2025. Each bundle was broken out by year of availability, corresponding to the years in which the Company launches new UEE programs. In each year for which a new UEE program was available for model selection, the model was given the option of either a Base bundle or a High Incentive Pricing bundle. Bundle 1, representing the current UEE programs, was the only UEE bundle prescribed for all portfolios. Table 3-29 below shows the UEE Bundles by incentive type (base or high). Additional details and a complete listing of EE programs are provided in Appendix H.

Table 3-29: EE Bundles Available for Selection in Modeling

Bundle	Type	Year Available	Max Annual Savings (GWh)	Levelized Cost ($/MWh)
Bundle 1	Base	Current	357	$28.86
Bundle 2	Base	2027	459	$32.46
Bundle 7	High	2027	552	$51.22
Bundle 3	Base	2030	667	$33.28
Bundle 8	High	2030	789	$52.72
Bundle 4	Base	2034	1,042	$27.59
Bundle 9	High	2034	1,307	$43.34
Bundle 5	Base	2042	403	$27.59
Bundle 10	High	2042	488	$42.68

Demand Response

Controllable demand response customer programs serve an important role in meeting system peak demand requirements. When seasonal peak loads occur, MISO system operators can initiate DR events to lower customer energy consumption and quickly reduce the stresses on the system that can occur during these high demand periods. DR programs send signals directly to customer equipment, such as thermostats and water heaters, to immediately lower energy usage. Alternatively, large commercial and industrial customers can participate in customized DR programs where Duke Energy Indiana communicates the request to reduce load during high system demand periods. Employees of those firms comply by flexibly choosing what load to reduce to meet their previously agreed upon demand reduction commitments. DR customers are compensated monthly for opting in to these programs in return for their commitment to reducing consumption during peak periods. Current Duke Energy Indiana DR programs include Power Manager®, Power Manager for Business, PowerShare® and Savings On Demand, and special contract customer demand response. Further information on DR programs can be found in Appendix H.

In addition to these existing DR programs, the 2024 IRP includes a new undesignated DR resource that serves as a representative proxy for future demand response initiatives. DR capacity is modeled as a peaking resource like traditional generation and contributes to capacity planning reserve margins. DR is grossed up for reserve margin and transmission losses. Effective utilization of DR programs can decrease the runtime of aging, more expensive generation resources and potentially defer the need for new supply-side peaking resources. Table 3-30 below summarizes the peak winter capacities of Duke Energy Indiana's DR programs in the IRP.

The Company is closely monitoring the implementation of FERC Order 2222 ("FERC 2222"). The peak reduction identified in the 2024 IRP assumes no impact from FERC 2222 until 2030. More detail on how the Company is monitoring and including FERC 2222 in the IRP is provided in Appendix H.

Table 3-30: Demand Response Winter Peak Load Capability

Year	Winter (MW)
2025	403
2030	452
2035	466

Integrated Volt/Var Control

Duke Energy Indiana is continuing the implementation of IVVC to better manage the application and operation of voltage regulators (Volt) and capacitors (VAR) on the Duke Energy Indiana distribution network. A single control system, the Distribution Management System (“DMS”), optimizes the operation of these devices, resulting in grid efficiency and ultimately reducing retail load. Duke Energy Indiana primarily operates IVVC in the form of Conservation Voltage Reduction, which supports continuous voltage reduction and energy conservation on a year-round basis. This approach not only reduces the amount of generation required to meet customer demand, but also helps reduce emissions from the avoided generation. Despite the continuous operation, the savings from IVVC could be handled comparably to demand response mechanisms that focus on reducing customer energy consumption during periods of heightened grid demand. In 2023, Duke Energy Indiana received approval from MISO to register IVVC as a Load Modifying Resource (“LMR”). The implementation of IVVC as an LMR is advantageous for customers and the Company, as it reduces the amount of capacity that the Company would otherwise need to procure to satisfy MISO requirements.

The deployment of the IVVC program for Duke Energy Indiana began in 2019 under TDSIC 1.0 and is ongoing under TDSIC 2.0. The program is expected to reduce the upcoming demands on the distribution system by approximately 0.69% in 2024, with a forecasted reduction of about 0.8% in 2029 and beyond. The supply and demand impacts of the IVVC program are included in IRP capacity expansion and production cost modeling.

Table 3-31 below provides projected winter peak load reductions from IVVC in 2025, 2030, and 2035.

Table 3-31: IVVC Winter Peak Load Reduction Shaving Capacity

Year	Winter (MW)
2025	41
2030	46
2035	46

Rate Design and Other Customer Programs

In addition to the energy efficiency, demand response, and voltage optimization resources included in the IRP analytics, the Company is also pursuing customer programs to facilitate electric vehicle adoption, provide more direct access to renewable energy sources, and manage customer demand through innovative time-of-use rates. While not directly included in IRP analytics, the impacts of these programs will be seen in future IRPs, particularly through the load forecast, as they are approved and implemented. Additional details on customer programs are provided in Appendix H.

Chapter 4: Candidate Resource Portfolios

Highlights

- The comprehensive 2024 Integrated Resource Plan analysis was structured around six generation strategies evaluated under three different worldviews, supplemented by several strategy variations and robust risk analyses, ultimately yielding a diverse set of resource portfolios supported by extensive sensitivity analysis and stochastic risk assessment.
- No generation strategy is consistently the best performer with respect to all planning objectives. Each strategy outperforms the group on certain metrics while underperforming on others.
- Strategies that rely on aging steam units deep into the 20-year planning period require lower levels of new resource additions but result in higher total costs and elevated reliability and cost risk. Strategies that retire most or all existing coal units by 2032 (the deadline under Clean Air Act Section 111(d)) transition more rapidly to efficient, cost-effective resource mixes but do so at the expense of greater near-term customer bill impacts and higher execution risk.
- In addition to the scorecard metrics and thorough quantitative analytics informing selection of a Preferred Portfolio, the Company must equally consider qualitative factors influenced by the continuously evolving energy landscape to ensure Duke Energy Indiana's portfolio and pathway remain flexible in the face of significant uncertainty.

This Chapter provides details on the candidate resource portfolios for the 2024 Duke Energy Indiana Integrated Resource Plan ("IRP"). As described in Chapter 2 (Methodology), Duke Energy Indiana (or the "Company") evaluated three scenarios (or "worldviews") and developed six generation strategies informed by the Environmental Protection Agency's ("EPA") Clean Air Act ("CAA") Section 111 May 2024 Final Rule ("EPA CAA Section 111 Rule"). Each generation strategy explores potential transition options for the existing coal fleet, including modification to allow co-firing of coal and natural gas fuel, full conversion to natural gas fuel, or retirement. Retiring units are replaced with new, more efficient and reliable resources, often repurposing the existing site and adding incremental generating capacity to serve growing load and meet Midcontinent Independent System Operator ("MISO") seasonal planning reserve margin requirements. This Chapter also includes an evaluation of the generation strategies with respect to the resource planning objectives. As outlined in Chapter 2, the objectives include (1) reliability, (2) customer affordability, (3) environmental sustainability, (4) resiliency, (5) stability, and (6) accounting for risk and uncertainty. Additional detail regarding portfolio analytics and evaluation is presented in Appendix C (Quantitative Analysis).

Overview of Resource Portfolios

As described in Chapter 2, the analytical framework for the 2024 IRP consists of two "bookend" generation strategies, three "blend" strategies, and a stakeholder-inspired strategy, all of which achieve compliance with the EPA CAA Section 111 Rule. The Company developed three resource portfolios consistent with each of these strategies, one tailored to each of the three scenarios considered in this IRP.

The scenarios developed for the 2024 IRP analysis are (1) Reference, which includes the Company's base case forecasts and expectations for the future, (2) Aggressive Policy & Rapid Innovation ("Aggressive"), which assumes regulatory and technological factors incentivize and enable a more rapid energy transition, and (3) Minimum Policy & Lagging Innovation ("Minimum"), which assumes a more lenient regulatory environment, including reversal of the EPA CAA Section 111 Rule, and a slower pace of energy transition.

The "bookend" generation strategies would, on one end of the spectrum, modify most existing coal-fired units to burn natural gas fuel, either 100% or co-fired with coal (the "Convert/Co-fire Coal" strategy) or, on the other end of the spectrum, retire and replace all existing coal-fired steam units by 2032 (the "Retire Coal" strategy). The results of the Convert/Co-fire Coal and Retire Coal strategies informed the development of the blended generation strategies that explore various combinations of conversions and retirements of existing coal-fired units. Those three generation strategies are defined as Convert Cayuga ("Blend 1"), Co-fire/Retire Gibson ("Blend 2") and Convert/Co-fire Gibson ("Blend 4"). The stakeholder-informed strategy, developed over several months in collaboration with a stakeholder group, evaluates an accelerated timeline for coal conversions and retirements, and is referred to as "Exit Coal Earlier (Stakeholder)." Development of the Exit Coal Earlier (Stakeholder) strategy began with feedback the Company received during the first public stakeholder meeting, where it was suggested that Duke Energy Indiana should include in its IRP a candidate portfolio that retires all coal units by 2030. Following that February 2024 meeting, Duke Energy Indiana worked with interested stakeholders to develop an aggressive generation strategy that would accelerate the the timing of coal retirements.

In addition to the 18 portfolios developed for the generation strategies (six strategies across three worldviews), the Company evaluated several strategy variations, including a "No 111" case optimized to the Reference Scenario without the constraints imposed by the EPA CAA Section 111 Rule. The six generation strategies and the "No 111" case are summarized in Figure 4-1 below.

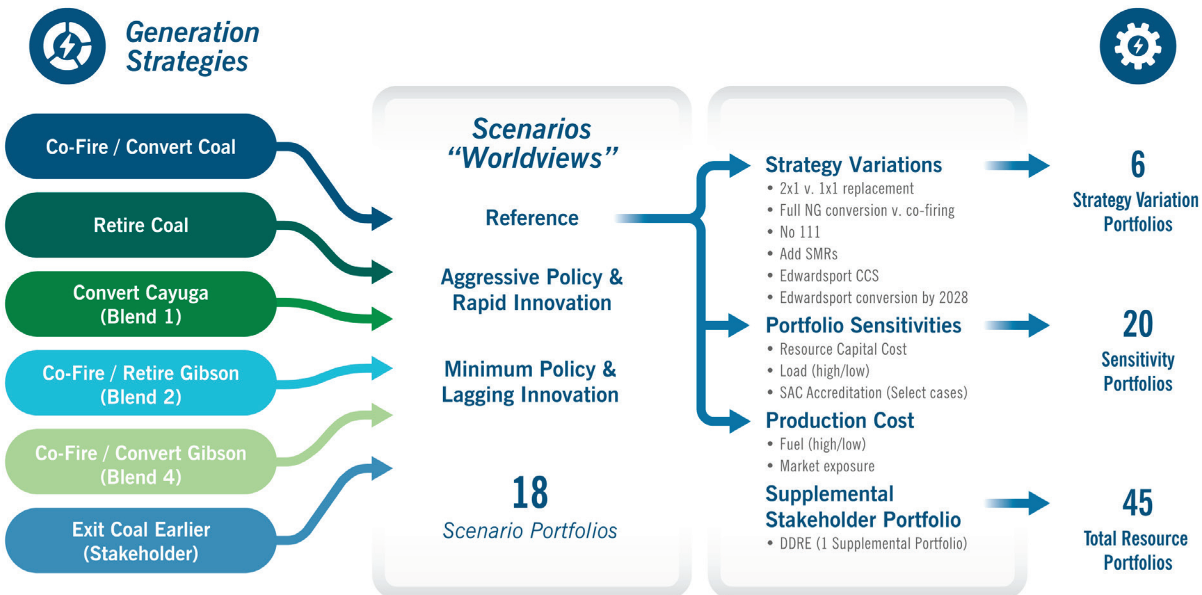
Figure 4-1: 2024 IRP Generation Strategies and "No 111" Case

<table>
<tr><th>UNIT</th><th>Convert/ Co-Fire Coal</th><th>Retire Coal</th><th>Blend 1</th><th>Blend 2</th><th>Blend 4</th><th>Exit Coal Earlier (Stakeholder)</th><th>No 111</th></tr>
<tr><td>Cayuga 1</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="6">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td colspan="2">Retire by 1/1/2030</td><td rowspan="2">NG Conversion by 1/1/2029</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Cayuga 2</td><td colspan="2">Retire by 1/1/2031</td></tr>
<tr><td>Gibson 1</td><td rowspan="2">Co-fire by 1/1/2030</td><td rowspan="4">Retire by 1/1/2032</td><td colspan="2" rowspan="2">Co-fire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">Retire by 1/1/2036</td></tr>
<tr><td>Gibson 2</td></tr>
<tr><td>Gibson 3</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Gibson 4</td></tr>
<tr><td>Gibson 5</td><td colspan="7">Retire by 1/1/2030</td></tr>
<tr><td>Edwardsport</td><td colspan="6">NG Conversion by 1/1/2030</td><td>NG Conversion by 1/1/2035</td></tr>
</table>

Note: Natural gas ("NG") conversion involves modifying existing infrastructure to use 100% natural gas fuel instead of coal for electricity generation. Co-firing involves infrastructure modification to use 50% natural gas fuel at the coal unit.

Figure 4-2 below summarizes the 2024 IRP analytical framework overall, including the generation strategies, sensitivities, strategy variations, and sensitivity analyses.

Figure 4-2: 2024 IRP Analytical Framework



Beginning-of-Year Convention

The Company conducted capacity expansion modeling using a beginning-of-year ("BOY") convention, meaning that resource changes (new unit additions, unit retirements, contract expirations, and unit conversions) occur on January 1st of each year for modeling purposes. Accordingly, capacity amounts and resource changes discussed in this Chapter are presented on a BOY basis or described as occurring "by" a given year.

Impacts of the Changing Energy Landscape

As detailed in Chapter 1 (Planning for the Future Energy Landscape), there has been a profound transformation in the energy landscape since the previous IRP in 2021. Consequential changes in the marketplace and regulatory environment have led the Company to make certain course adjustments, which is an important feature of the iterative IRP process. These changes are reflected in the 2024 IRP generation strategies.

Since the 2021 IRP, inflation and supply chain challenges have led to increasing costs and prolonged project lead times. Delays in MISO's interconnection queue and permitting have compounded this increase in project lead times. These challenges are affecting all resource types and have consequential impacts to resource planning by potentially impacting power producers' ability to add resources to the system in the time frame and quantity needed.

As detailed in Chapter 3 (Key Assumptions), MISO introduced the SAC construct beginning with the 2022/2023 planning year, under which resource capacity ratings are assigned on a seasonal basis. This had a direct impact on intermittent resources – for example, the winter capacity value assigned to solar under the SAC construct is close to zero. MISO continues to reform and refine its capacity accreditation standards and in March 2024 filed with the Federal Energy Regulatory Commission ("FERC") for approval to implement the Direct Loss of Load ("DLOL") accreditation methodology beginning with the 2028/2029 planning year. The DLOL approach will enhance capacity accreditation with the introduction of probabilistic assessment of effective load carrying capability for specified resource classes.

Further, in May 2024, the EPA finalized the CAA Section 111 Rule, which dictates specific actions for existing coal-fired generation and new natural gas generation, as detailed in Appendix J (Environmental Compliance). The EPA CAA Section 111 Rule set the foundation for identifying compliance pathways available for Duke Energy Indiana's existing coal units and establishing the 2024 IRP generation strategies.

In addition to near-term complexities and uncertainty, the Company is monitoring the potential for significant load increases from economic development in the service area. Given the changes in the energy landscape since the 2021 IRP and the reasonable anticipation of continued change into the future, the Company employed a robust analytical framework to identify a resource plan that complies with existing regulations yet provides flexibility to adjust to changing conditions.

Resource Decisions Common to All Portfolios

As discussed in Chapter 2, certain resource decisions and changes are common to all portfolios. These include:

- Completion of the 199 megawatt ("MW") Speedway Solar facility by the end of 2025
- Expiration of the 100 MW Benton County Wind PPA by the beginning of 2028
- Retirement of Gibson Unit 5 by the beginning of 2030
- Retirement of Noblesville combined cycle by the beginning of 2035
- Expiration of 25 MW of solar PPAs by the beginning of 2036

Results Summary

Reference Scenario results for all six generation strategies exhibit the same general trends over the planning period, influenced by the requirements of the EPA CAA Section 111 Rule. In all strategies, the near-term energy and capacity needs from growing load are met with solar and energy storage added by 2030. From 2030 to the beginning of 2032, aging coal units are either (1) retired and replaced with more cost-effective, reliable and less carbon-intensive combined cycle ("CC") generators or (2) modified to allow for natural gas-fired operations (in some cases, co-fired with coal) in compliance with the EPA CAA Section 111 Rule. During this period of the early 2030s, natural gas accounts for a large share of the total energy mix, and carbon emissions fall steeply for all generation strategies. In the mid-2030s, a growing share of energy is served with relatively lower-cost energy purchased on the MISO market, which offers cost savings for customers. This shift is due to two factors: (1) the 40% annual capacity factor limit on new CCs under the EPA CAA Section 111 Rule, and (2) the relatively high dispatch cost of aging steam units, which struggle to compete economically in the transitioning MISO market. The increase in market purchases is based on economics and does not indicate an inability of the Duke Energy Indiana fleet to meet customer demand. As detailed later in this Chapter, the Company conducted stochastic analysis of energy sufficiency to verify each portfolio's capability to serve customer demand with Duke Energy Indiana portfolio resources.

Notably, the economics of renewables improve considerably over the course of the 2030s, and all strategies result in substantial additions of wind and solar in the second half of the planning period, with renewables accounting for the majority of total energy by 2044. CO_2 emissions continue to decline steadily over this period alongside the growing contributions from renewable energy resources. Dispatchable thermal resources, including new CCs, existing simple cycle combustion turbines ("CT"), and, in some cases, modified steam units that formerly burned coal, remain critical for reliability throughout the planning period, with storage playing an increasingly important role over time.

The results of the "No 111" strategy variation, which the Company evaluated in the Reference Scenario absent the requirements of the EPA CAA Section 111 Rule, show two notable differences from the general trends in the Reference Scenario results. Given that new CC resources in the "No 111" case are not subject to a stringent annual capacity factor constraint, these highly efficient advanced class CCs are able to generate more energy, thus economic purchases from the MISO energy market make up a much smaller component of the total energy mix in the mid-2030s and the need for additional energy-producing resources is considerably reduced in the latter half of the planning period.

Results for the six generation strategies *converge* more tightly in the Aggressive Policy & Rapid Innovation Worldview, as more stringent regulation minimizes available options. In addition to the EPA CAA Section 111 Rule, the Aggressive Worldview includes a tax on carbon emissions and a more rapid decline in costs for renewables and energy storage resources. With additional regulatory constraints limiting the value of thermal generation and rapidly declining costs improving the value of renewables, wind and solar are added in larger amounts earlier in the planning period in all strategies. Storage plays a large role as a capacity-only resource, but dispatchable thermal resources also remain critical for reliability. CO_2 emissions decline at an accelerated rate compared to the Reference Scenario, driven in part by the carbon tax and higher projected fuel prices contemplated in the Aggressive Worldview.

In the Minimum Policy & Lagging Innovation Worldview, by contrast, results *diverge* more across generation strategies, as fewer constraints are placed upon resource decisions. In this potential future, the EPA CAA Section 111 Rule is rolled back and the capacity factor constraint on new natural gas resources is lifted. Strategies that retire more coal capacity and replace it with new generation benefit from the less restrictive regulatory environment, while strategies that pursue co-firing and full natural gas conversion of existing steam units look more to the MISO market to provide low-cost energy due to the relatively high cost of energy from the aging steam units. Without the capacity factor limitations of the EPA CAA Section 111 Rule, new advanced class CCs produce a majority of the energy in most generation strategies, reducing the need for other energy resources such as solar and wind. Expectedly, carbon emissions in the Minimum Worldview decline at a slower rate relative to the other worldviews.

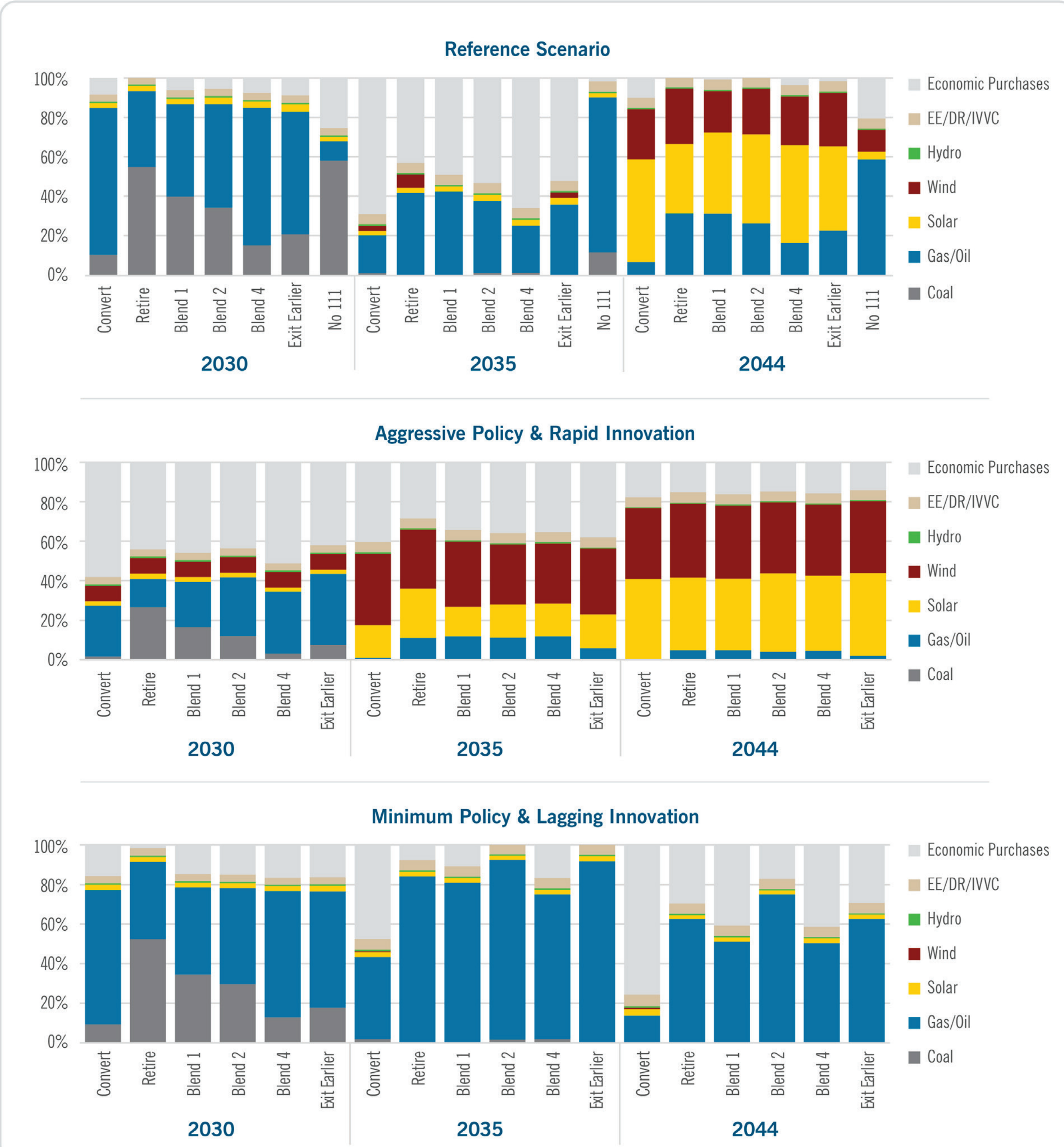
Table 4-1 below provides a summary of supply-side resource changes for the six generation strategies and the “No 111” case in the Reference Scenario.

Table 4-1: Reference Scenario Resource Changes (MW) by 1/1/2032 for Generation Strategies and the No 111 Strategy Variation

Generation Strategy	Coal Retirements	Conversions/ Co-firing	CC	Solar	Storage
Convert/Co-fire Coal	(313)	2,844 (Conv.) 1,266 (Co-fire)	–	349	450
Retire Coal	(3,837)	586 (Conv.)	3,595	399	300
Blend 1	(2,839)	1,584 (Conv.)	2,876	399	400
Blend 2	(2,571)	586 (Conv.) 1,266 (Co-fire)	2,876	499	400
Blend 4	(1,311)	1,847 (Conv.) 1,266 (Co-fire)	1,438	449	425
Exit Coal Earlier (Stakeholder)	(2,839)	1,584 (Conv.)	2,157	549	675
No 111 (Strategy Variation)	(2,571)	–	3,595	299	500

Figure 4-3 below provides the energy mix results for the generation strategies in each of the three scenarios at specific snapshots in time (2030, 2035, and 2044). As noted previously, each portfolio has sufficient resources to serve customers, but economic participation in the MISO energy market serves to reduce costs for customers. This is reflected in the energy mixes below, particularly in 2035. For comparative purposes, charts for the Reference Scenario include results of the “No 111” strategy variation.

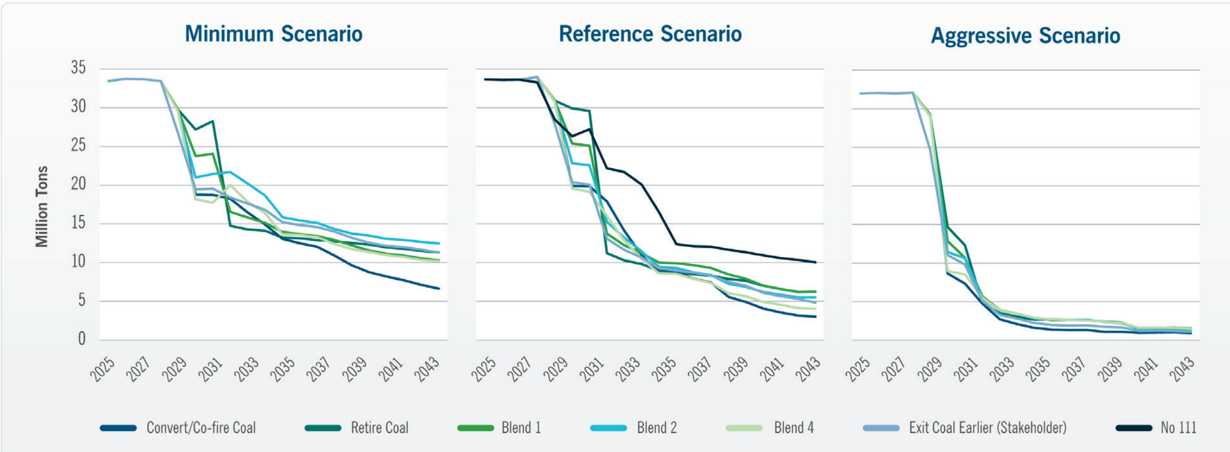
Figure 4-3: Modeled Energy Mix by Generation Strategy and Scenario



Note: Energy efficiency ("EE"); demand response ("DR"); integrated volt-var control ("IVVC")

As illustrated in Figure 4-4 below, CO_2 emissions track the changing energy mix over time, with steep declines in the early 2030s when the energy mix transitions from coal to natural gas. This is followed by a continued steady downward trend, particularly in the Reference and Aggressive scenarios, as renewable resources contribute a greater share of the energy mix.

Figure 4-4: Annual CO_2 Emissions for Generation Strategies by Worldview



Capacity Changes Across Worldviews

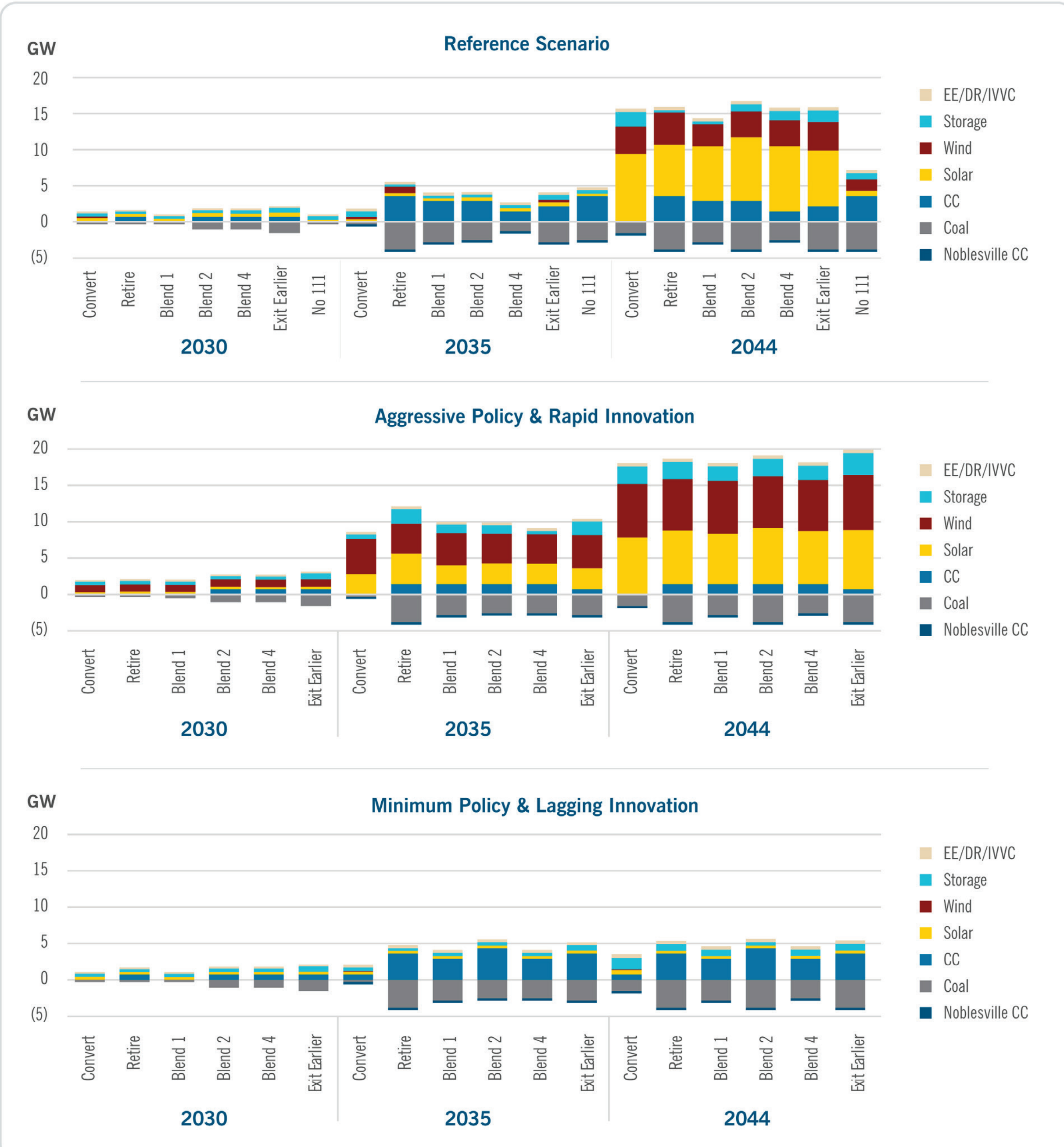
Resource changes in the candidate portfolios for the 2024 IRP can generally be grouped into three stages. First, across all generation strategies and worldviews, solar and battery energy storage are added in the late 2020s to meet near-term energy and capacity needs. Next, from the beginning of 2030 to 2032, the coal units transition to comply with the EPA CAA Section 111 Rule. In this stage, existing coal-fired resources are modified to enable these units to burn natural gas or are retired and replaced with highly efficient and reliable advanced class CCs that provide additional capacity to support Indiana's growing economy and offer operational flexibility to support future deployment of renewables. The energy and capacity mixes for each portfolio by 2035, the middle of the 20-year planning period, reflect these changes. Finally, over the remainder of the planning period in the Reference and Aggressive scenarios, there are increasingly substantial additions of wind and solar for energy production and battery storage for capacity due to the improving relative economics of these resources.

In the absence of aggressive regulatory deadlines, the "No 111" variation follows a more moderate pace of transition, with no coal unit modifications (e.g., conversion to run on natural gas) and two units continuing to burn coal through 2035. However, in this case, all existing coal-fired steam units are retired by the end of 2035 and replaced with a mix of advanced class CCs, wind, solar, and battery energy storage.

In the Aggressive Worldview, which includes a combination of tightened regulatory constraints on thermal resources and more favorable economics for renewables and energy storage, the addition of wind, solar, and battery resources is accelerated, and new CC additions are more limited. Conversely, in the Minimum Worldview, a future with lower fuel prices and without regulatory constraints limiting the annual capacity factor for new CCs, there is little need for new energy resources like wind and solar, while battery energy storage remains an important capacity resource.

Figure 4-5 below presents resource additions and retirements for each generation strategy in each of the three planning scenarios. The first chart of the figure, showing generation strategy results for the Reference Scenario, also includes the "No 111" variation.

Figure 4-5: Cumulative Resource Additions and Retirements (Installed GW, Beginning-of-Year Basis)

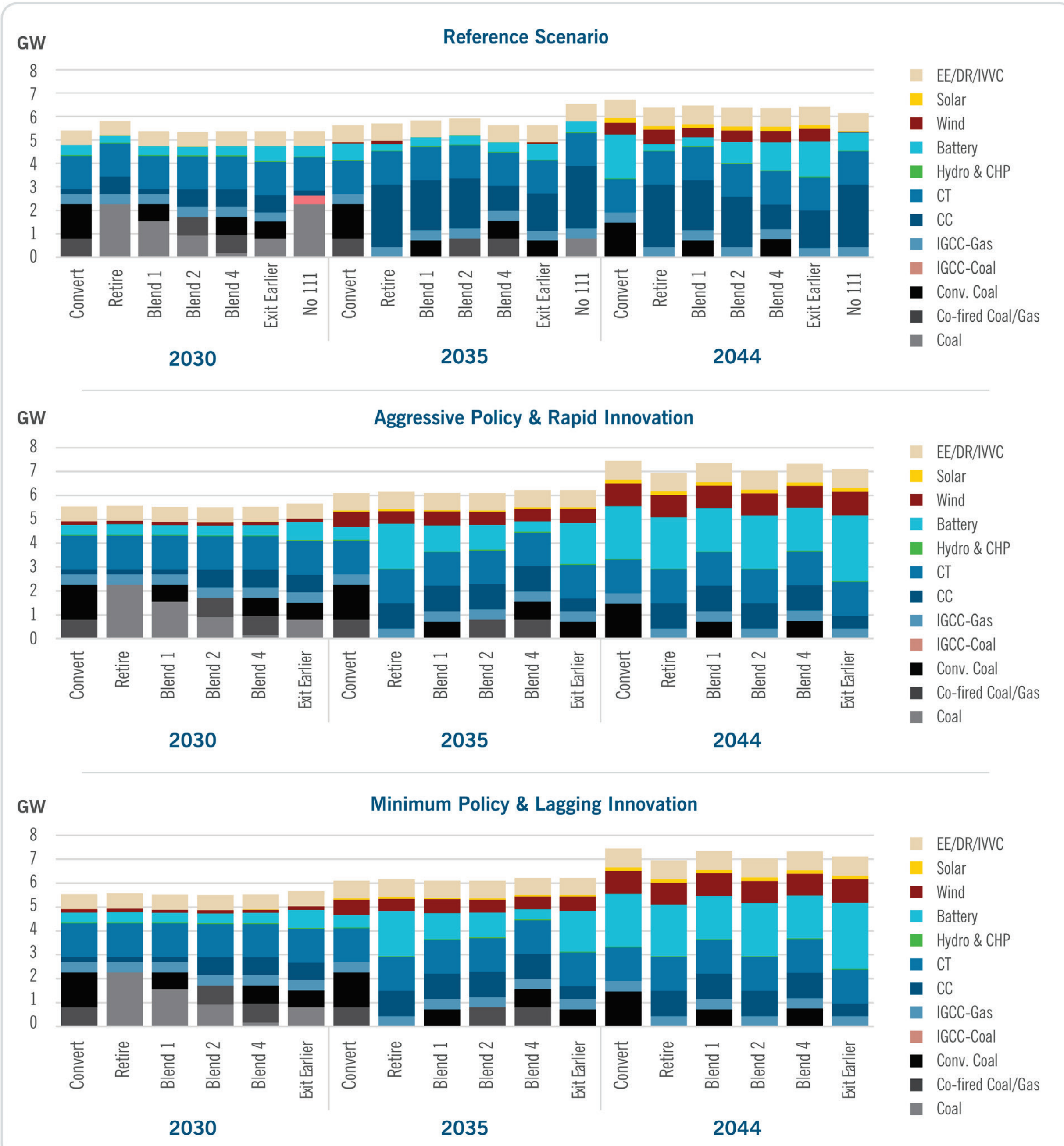


Thermal generating capacity, particularly fast-ramping CTs and new, highly flexible advanced class CCs, continues to be the foundation of system reliability throughout the planning period for all generation strategies in all planning scenarios. These resources provide cost-effective capacity, are available on demand, are able to run for days or weeks at a time without needing to be recharged, and have the flexibility required to accommodate increasing levels of variable renewable energy generation. Over time, the growing market share of variable energy renewables increases the value of battery energy storage, and, by the same token, the value of flexible thermal generating capacity as a complementary capacity resource grows as well. This trend is accelerated in the Aggressive Scenario.

In the Reference Scenario, strategies that retain more existing steam capacity through the 2030s (Convert/Co-fire Coal, Blend 4) rely more on batteries to meet incremental capacity needs and ultimately to replace retiring steam capacity toward the end of the planning period. Similarly, the relatively short lead time to develop new battery projects makes them an important source of capacity to replace coal units that retire by 2030 according to the aggressive timeline pursued under the Exit Coal Earlier (Stakeholder) strategy.

Figure 4-6 below shows the firm capacity mix on a winter basis for each generation strategy in each planning scenario at snapshots in time. Results of the “No 111” strategy variation are included for the Reference Scenario.

Figure 4-6: Firm Winter Capacity (GW, Beginning-of-Year Basis)



Note: Combined heat and power ("CHP"); Integrated gasification combined cycle ("IGCC")

Total Estimated Cost by Generation Strategy

Total portfolio cost, as measured by the present value of revenue requirements (“PVRR”), varies considerably across scenarios. Costs are highest in the Aggressive Scenario, which contemplates the tightest regulatory constraints, including a tax on CO_2 emissions in addition to the requirements of the EPA CAA Section 111 Rule. Similar to the trend for new resource additions discussed above, these constraints drive convergence across generation strategies, and the range of PVRR results is most narrow in the Aggressive Worldview. The lowest cost strategy in the Aggressive Scenario is more expensive than the highest cost strategy in the Reference Scenario, as the accelerated cost declines for renewables and energy storage that are part of the Aggressive Worldview fail to offset the cost impact of the CO_2 tax and higher fuel prices.

PVRR results diverge most in the Minimum Scenario, which contemplates relaxed regulatory restrictions. With more flexibility, the total cost of each generation strategy is lower in the Minimum Scenario than in the Reference Scenario.

In the Reference Scenario, PVRR is highly correlated with the retention of existing steam generators. The Retire Coal strategy results in the lowest total cost to customers over the planning period of any strategy compliant with the EPA CAA Section 111 Rule, as aging coal units are retired and replaced with a diverse mix of advanced class CCs, solar, wind, and battery energy storage. The Convert/Co-fire Coal strategy, on the other hand, results in the highest total cost for customers, as increased maintenance, compliance, and operating costs related to the aging units more than offset the lower capital expenditures for new resource additions. However, there is an inverse effect for near-term customer bill impacts — measured by projected compound annual growth rate (“CAGR”) — with the Retire Coal strategy requiring more near-term expenditures. Customer bill impact projections for the 2024 IRP generation strategies are explored in a later section of this Chapter.

As intended, the bookend strategies represent the two extremes, with the more aggressive Retire Coal strategy resulting in higher near-term cost impacts but an overall lower total cost, and the Convert/Co-fire Coal strategy resulting in lower near-term cost impacts but an overall higher total cost. The blend strategies provide more balanced results, with both total cost and near-term impacts falling near the middle of the range.

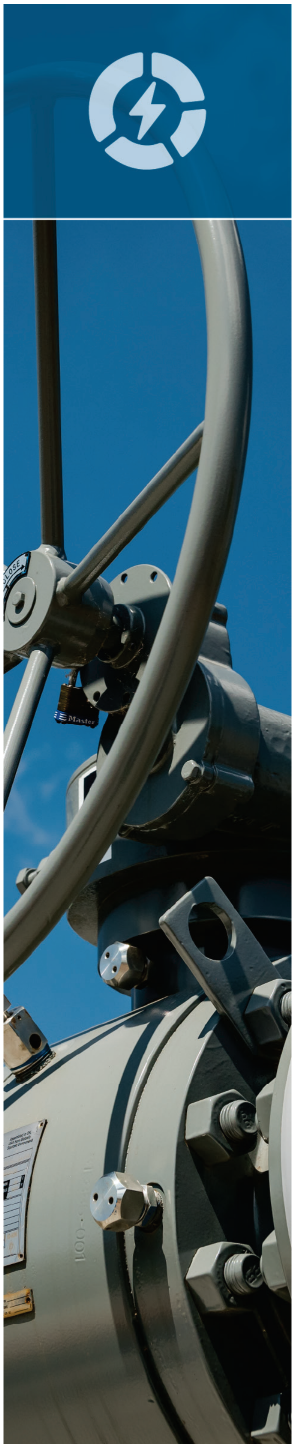
The cost of the “No 111” case is lower than the strategies developed to comply with the EPA CAA Section 111 Rule in both the near term and over the planning period. PVRR results by generation strategy and planning scenario are presented in Figure 4-7 below.

Figure 4-7: PVRR by Generation Strategy Including "No 111" Strategy Variation

Results Across Generation Strategies in the Reference Scenario

This section provides detailed results for each of the six generation strategies in the Reference Scenario, as well as the results of the "No 111" strategy variation.

Convert/Co-fire Coal Generation Strategy



Convert/Co-fire Coal is one of the two “bookend” generation strategies for compliance with the EPA CAA Section 111 Rule that the Company evaluated in the 2024 IRP. For this strategy, the Cayuga coal units, Gibson units 3 and 4, and the Edwardsport IGCC unit are converted to 100% natural gas fuel. Gibson units 1 and 2 are modified to allow co-firing of coal and natural gas, while Gibson Unit 5 is retired. These changes all occur by the end of 2029 and are reflected starting January 1, 2030, in IRP modeling.

With most existing capacity remaining online into the late 2030s, near-term resource additions are limited to the minimum required to meet load growth projected in the base forecast. Solar (350 MW) and battery energy storage (450 MW) are added in the late 2020s to meet near-term energy and capacity needs. By 2039, when the co-fired Gibson units 1 and 2 reach mandated retirement under the EPA CAA Section 111 Rule, economics for new resources favor renewables and energy storage, and no new CC capacity is selected for this strategy.

The reliance on relatively inefficient aging steam units raises the overall dispatch cost of Duke Energy Indiana generation, and production cost model results show economic energy market purchases accounting for the majority of total energy for this strategy through the mid- to late 2030s. This substantial market exposure opens customers to cost risk related to fluctuations in market energy prices, in addition to the growing reliability and environmental compliance risk associated with the aging steam units. The relatively high operating and maintenance costs, including the cost of energy purchased in the MISO market, cause the Convert/Co-fire Coal strategy to have the highest PVRR of the strategies evaluated, while the limited near-term resource additions result in lower near-term customer bill impacts.

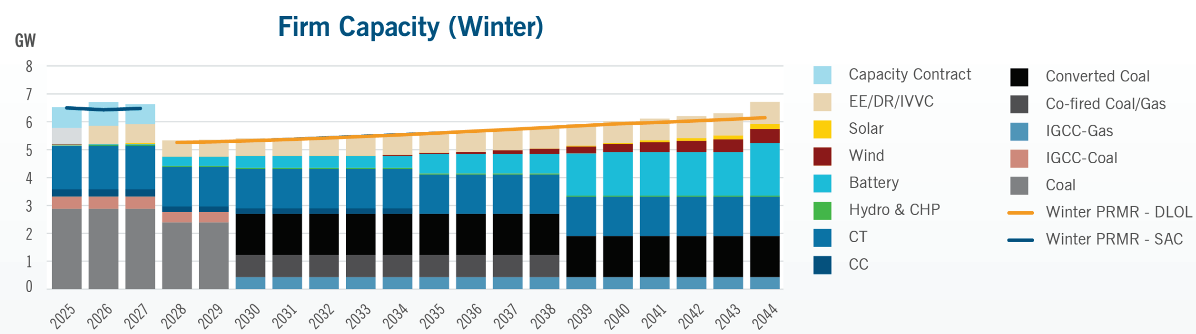
Figure 4-8 below presents a summary of the Convert/Co-fire Coal strategy.

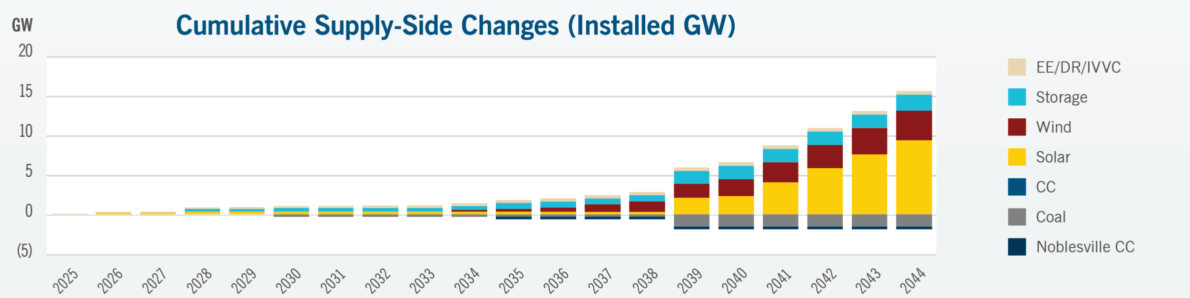
Figure 4-8: Convert/Co-fire Coal Generation Strategy Summary

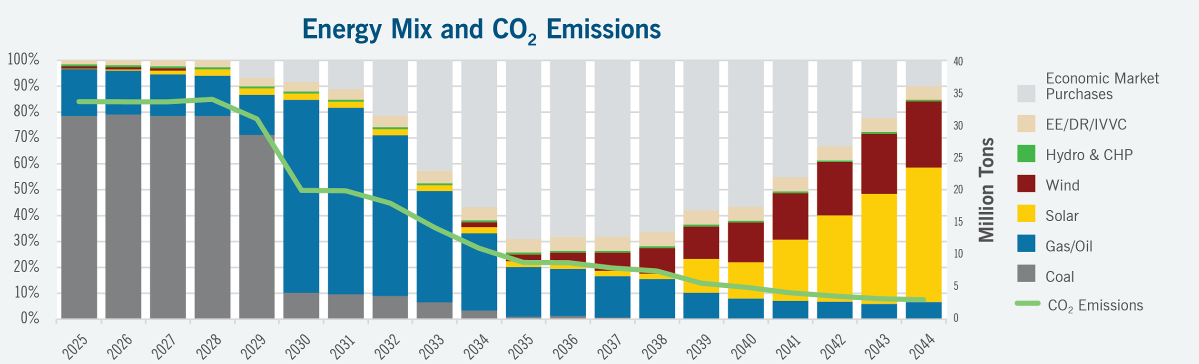
Convert/Co-Fire Coal

Customer Affordability Metrics	
PVRR ($B)	$25.0
Bill Impact (CAGR) 2030	3.9%
Bill Impact (CAGR) 2035	3.1%

- Continue operation of existing steam units in compliance with the EPA CAA Section 111 Rule by converting Convert Cayuga 1 & 2, Gibson 3 & 4, and Edwardsport to 100% natural gas fuel, and co-firing Gibson 1 & 2 on 50% natural gas by 2030.
- Add 350 MW of solar and 450 MW of battery energy storage by 2030 to meet near-term energy and capacity needs.
- Retire Gibson 5 by 2030.







Retire Coal Generation Strategy

Retire Coal serves as the other “bookend” strategy for EPA CAA Section 111 Rule compliance that the Company evaluated in the 2024 IRP. For this strategy, Gibson Unit 5 is retired by 2030, and all remaining coal-fired steam units are retired by 2032. Edwardsport IGCC is converted to natural gas fuel by 2030.

Near-term energy and capacity needs are met with solar and battery energy storage placed in service by 2030, and retiring coal units are replaced with reliable, efficient advanced class CCs that also provide incremental capacity.

The rapid transition from coal to advanced class CCs by 2032, supported by solar and battery energy storage, results in a highly efficient and economically competitive generating fleet. Production cost model results show lower levels of economic market energy purchases than in the Convert/Co-fire strategy, future reliability and environmental compliance risks are reduced, and the total cost over the planning period is the lowest of any of the 111-compliant generation strategies. However, the aggressive pace of new resource additions creates considerable execution risk and relatively high customer bill impact in the near term.

A summary of the Retire Coal strategy is presented in Figure 4-9 below.

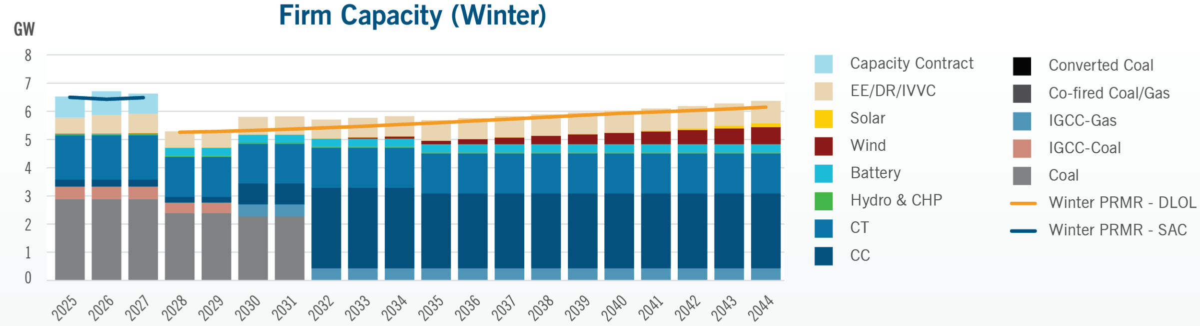
Figure 4-9: Retire Coal Generation Strategy Summary

Retire Coal

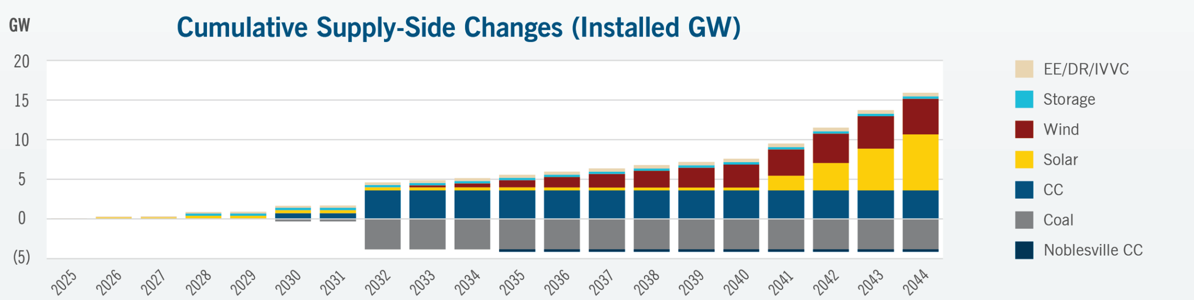
Customer Affordability Metrics	
PVRR ($B)	$23.6
Bill Impact (CAGR) 2030	3.7%
Bill Impact (CAGR) 2035	3.3%

- Retire Cayuga 1 & 2, Gibson 1-4 by 2032 in compliance with EPA CAA Section 111 Rule.
- Retire Gibson 5, convert Edwardsport to 100% natural gas fuel by 2030, also in compliance with EPA CAA Section 111 Rule.
- Add 400 MW of solar and 300 MW of battery energy storage by 2030, 3,595 MW of advanced class CCs by 2032.

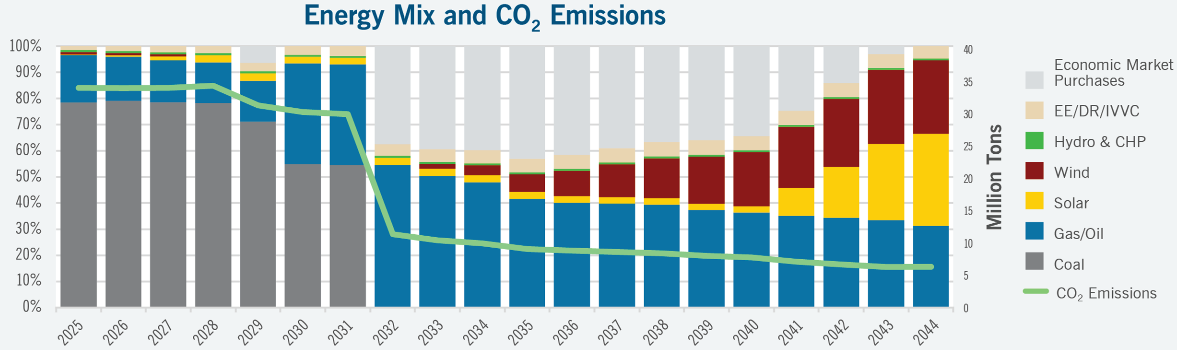
Firm Capacity (Winter)



Cumulative Supply-Side Changes (Installed GW)



Energy Mix and CO_2 Emissions



Convert Cayuga (Blend 1) Generation Strategy

Convert Cayuga (Blend 1) is the first of the "blend" generation strategies that Duke Energy Indiana developed for the 2024 IRP to explore options for balance between the two bookend strategies.

For this strategy, Cayuga units 1 and 2 and Edwardsport are converted to 100% natural gas fuel by 2030, while Gibson units 1-4 are retired by 2032. Gibson Unit 5 is retired by 2030. Near-term energy and capacity needs are met with solar and battery energy storage deployed by 2030. Two advanced class 2x1 CCs totaling 2,876 MW are added by 2032, providing efficient, reliable energy and capacity.

In contrast with Blend 2, in which Gibson units 1 and 2 are co-fired on coal and natural gas and therefore are required to retire by the end of 2038 under the EPA CAA Section 111 Rule, the converted Cayuga units contemplated in Blend 1 have no mandated retirement date. However, continued reliance on the aging steam units into the 2040s would carry substantial risk related to maintenance costs, reliability, and economic competitiveness.

In addition, continued operation of the Cayuga steam units could be complicated by the need to potentially add closed-cycle cooling to achieve compliance with sections 316(a) and 316(b) of the Clean Water Act, which govern discharge temperatures and intake structures, respectively.

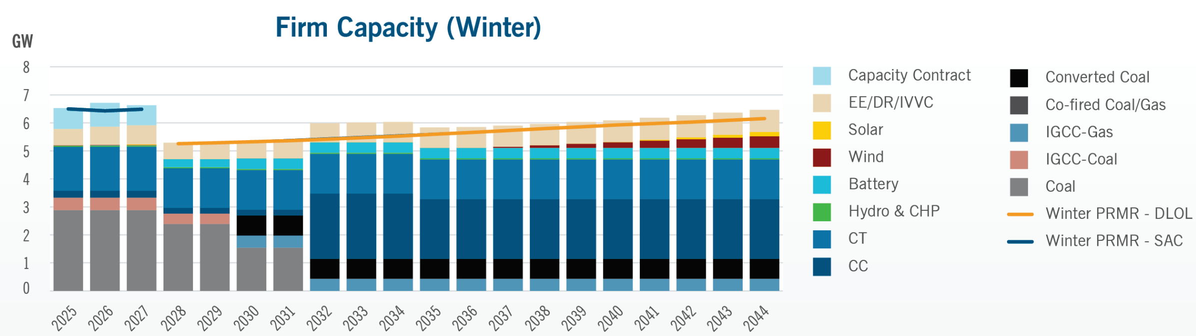
A summary of the Blend 1 strategy is captured in Figure 4-10 below.

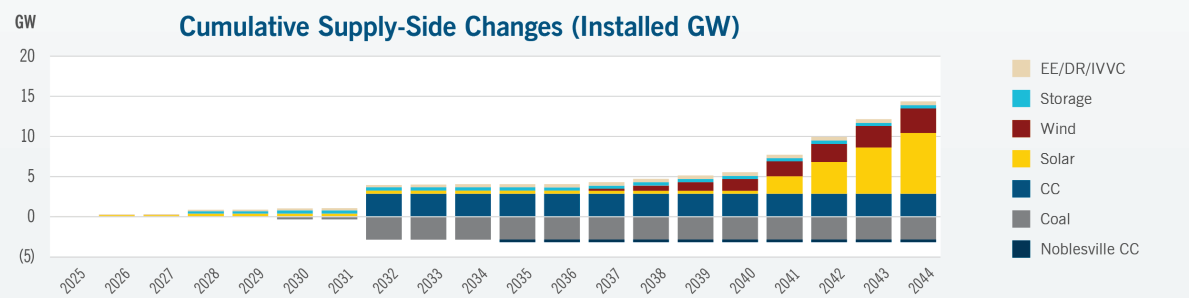
Figure 4-10: Convert Cayuga (Blend 1) Generation Strategy Summary

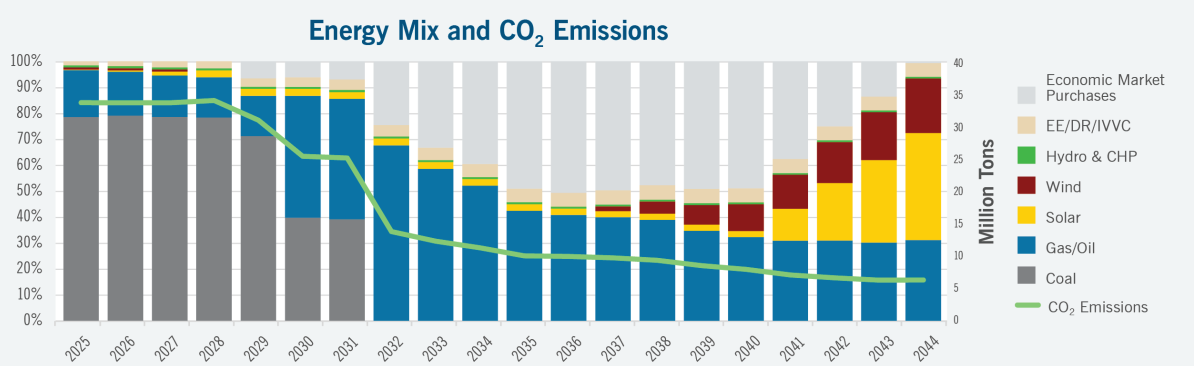
Convert Cayuga (Blend 1)

Customer Affordability Metrics	
PVRR ($B)	$24.2
Bill Impact (CAGR) 2030	3.9%
Bill Impact (CAGR) 2035	2.8%

- Convert Edwardsport and Cayuga units 1 & 2 to 100% natural gas fuel by 2030 in compliance with EPA CAA Section 111 Rule.
- Retire Gibson 5 by 2030, Gibson 1-4 by 2032, also in compliance with EPA CAA Section 111 Rule.
- Add 400 MW of solar and 400 MW of battery energy storage by 2030, 2,876 MW of advanced class CCs by 2032.







Co-fire/Retire Gibson (Blend 2) Generation Strategy

Co-fire/Retire Gibson (Blend 2) is the second blend strategy developed for the 2024 IRP and was identified as the 2024 IRP Preferred Portfolio. This strategy considers retirement of the Cayuga coal-fired units by 2030 and 2031, co-firing of Gibson units 1 and 2 and retirement of Gibson Unit 5 by 2030, and retirement of Gibson units 3 and 4 by 2032. Edwardsport is converted to natural gas fuel by 2030.

In the Reference Case portfolio for the Blend 2 strategy, two 1x1 CCs are added to the portfolio coinciding with the retirement of the Cayuga units, and a 2x1 CC is added at the time that Gibson units 3 and 4 retire. The Blend 2 portfolio also includes 500 MW of solar and 400 MW of battery energy storage added by 2030 to meet near-term energy and capacity needs. The two 1x1 CCs provide 440 MW of incremental capacity above the capability of the retiring Cayuga units, and the 2x1 CC adds 177 MW above the capacity of Gibson units 3 and 4.

In addition to providing incremental capacity, the advanced class CCs improve the reliability and economic competitiveness of the portfolio while mitigating risks related to maintenance costs and potential future environmental compliance costs associated with the aging coal units.

Importantly, the co-firing of Gibson units 1 and 2 improves fuel diversity and allows the units to operate through 2038 in compliance with the EPA CAA Section 111 Rule. Sustaining operation of these existing units, which have the newest emissions controls in the Company's fleet, mitigates execution risk and near-term cost impacts to customers.

The Blend 2 strategy, summarized in Figure 4-11 below, yields a balanced Reference Case portfolio, with the immediate addition of solar and battery storage, incremental capacity and improved reliability from advanced class CCs, and continued operation of existing steam units with the best emissions controls in the Company's portfolio.

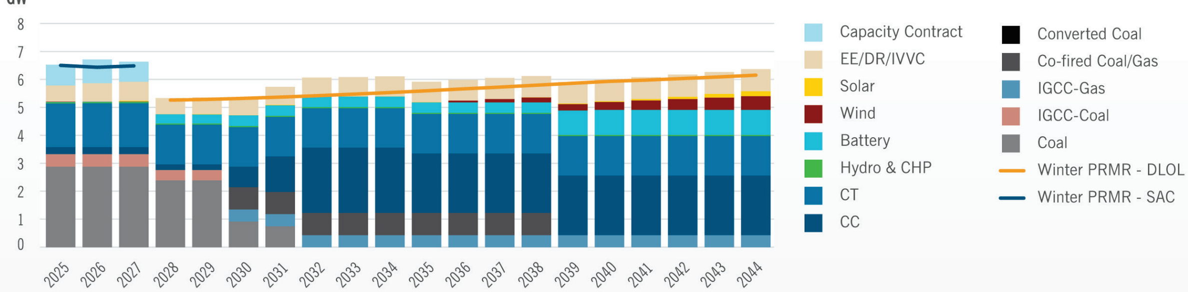
Figure 4-11: Co-fire/Retire Gibson (Blend 2) Generation Strategy Summary

Co-fire/Retire Gibson (Blend 2)

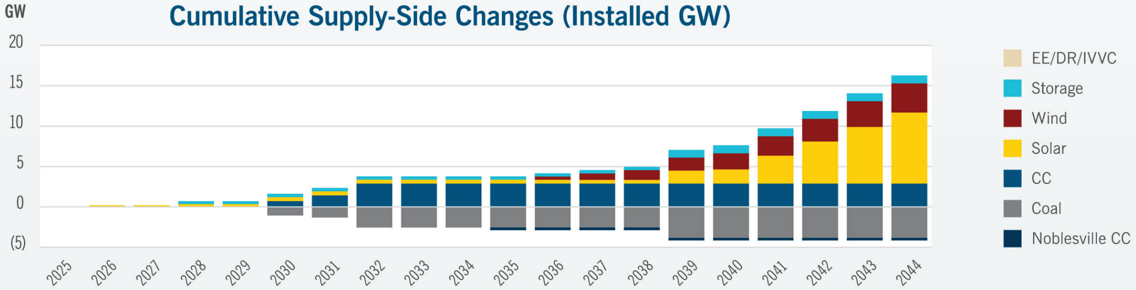
Customer Affordability Metrics	
PVRR ($B)	$24.3
Bill Impact (CAGR) 2030	4.0%
Bill Impact (CAGR) 2035	3.1%

- Co-fire Gibson 1 & 2 on 50% natural gas fuel, convert Edwardsport to 100% gas by 2030 in compliance with EPA CAA Section 111 Rule.
- Retire Cayuga 1 and Gibson 5 by 2030, Cayuga 2 by 2031, and Gibson 3 & 4 by 2032.
- Add 500 MW of solar and 400 MW of battery energy storage by 2030, 2,876 MW of advanced class CCs by 2032.

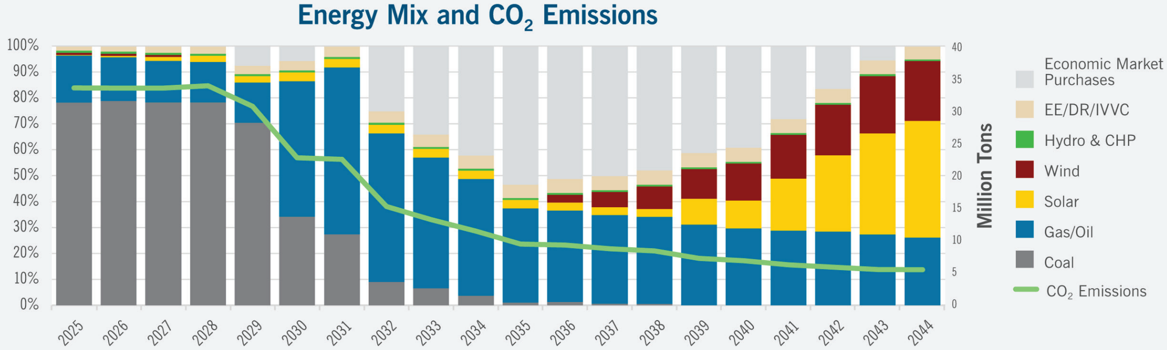
Firm Capacity (Winter)



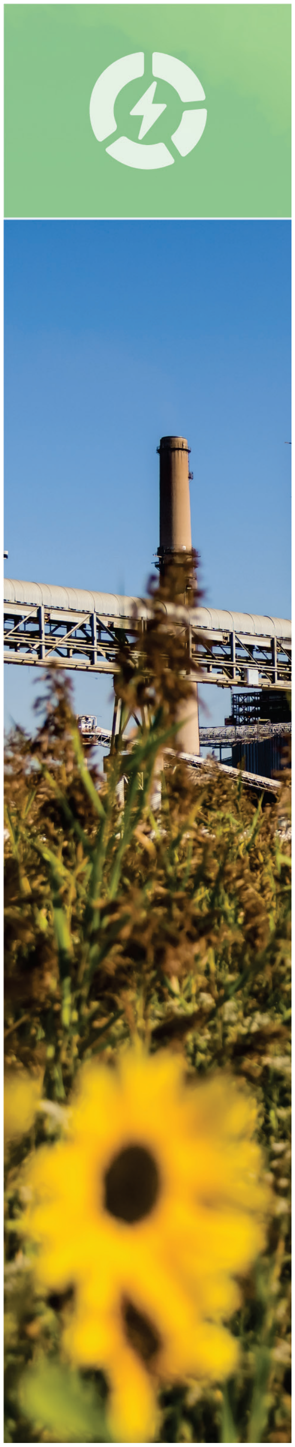
Cumulative Supply-Side Changes (Installed GW)



Energy Mix and CO_2 Emissions



Co-fire/Convert Gibson (Blend 4) Generation Strategy



The Co-fire/Convert Gibson ("Blend 4") generation strategy also explores options for continued operation of existing Gibson units in compliance with the EPA CAA Section 111 Rule.

As in Blend 2, the Cayuga coal units are retired by 2030 and 2031, Gibson units 1 and 2 are co-fired by 2030, Edwardsport is converted to natural gas fuel by 2030, and Gibson Unit 5 is retired by 2030. However, instead of retiring Gibson units 3 and 4, the Blend 4 strategy contemplates full natural gas conversion of those units to allow them to continue to operate through the entirety of the 20-year planning period.

In the Reference Case portfolio for Blend 4, two advanced class 1x1 CCs are added, coinciding with the retirements of the Cayuga coal units. These highly efficient units replace the retiring capacity and provide 440 MW of incremental capacity to support growing load. In addition, 450 MW of solar and 425 MW of battery energy storage are added by 2030 to meet near-term energy and capacity needs.

Blend 4 represents a somewhat slower pace of energy transition than Blend 2, falling closer to the Convert/Co-fire Coal strategy in that regard. As such, Blend 4 results in somewhat higher total cost than Blend 2, somewhat lower near-term bill impact, and elevated risk stemming from greater reliance on aging steam units through the late 2030s and into the 2040s.

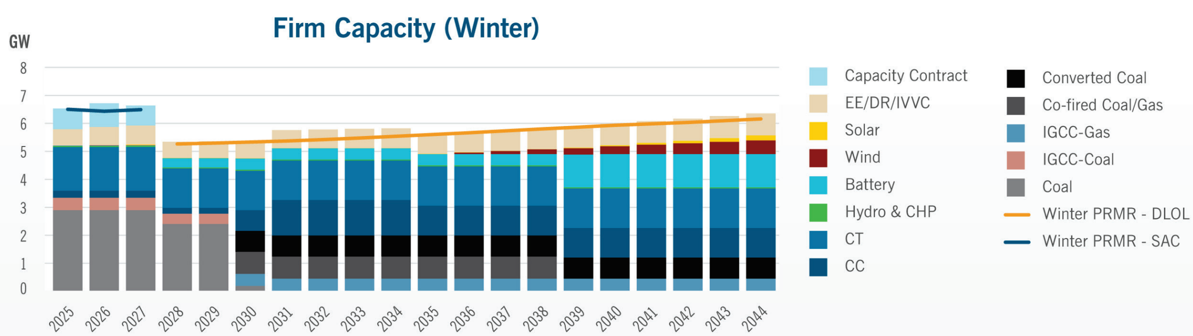
A summary of the Blend 4 strategy is provided in Figure 4-12 below.

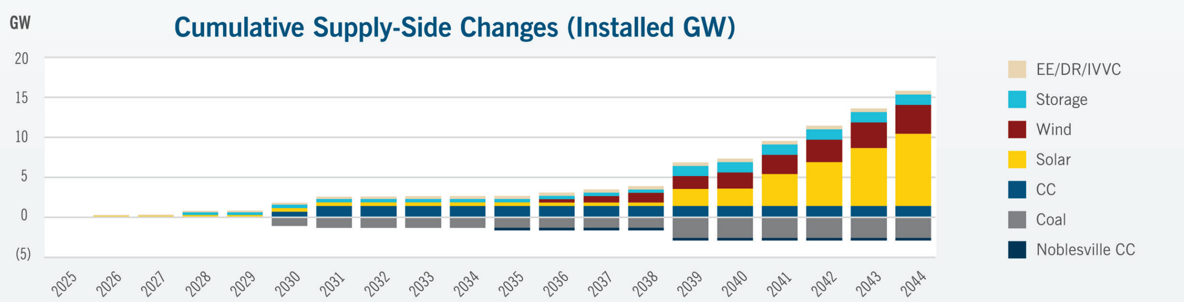
Figure 4-12: Co-fire/Convert Gibson (Blend 4) Generation Strategy Summary

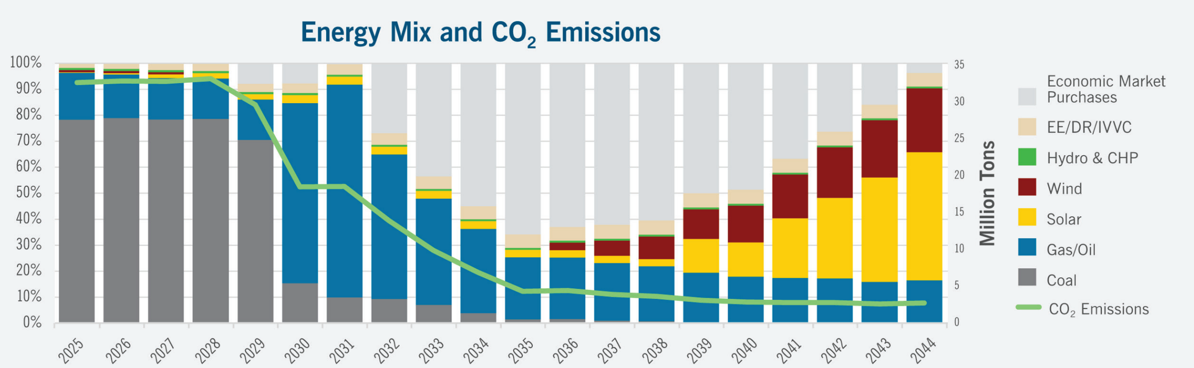
Co-fire/Convert Gibson (Blend 4)

Customer Affordability Metrics	
PVRR ($B)	$24.5
Bill Impact (CAGR) 2030	4.0%
Bill Impact (CAGR) 2035	2.9%

- Co-fire Gibson 1 & 2 on 50% natural gas fuel, convert Gibson 3 & 4 and Edwardsport to 100% gas by 2030 in compliance with EPA CAA Section 111 Rule.
- Retire Cayuga 1 and Gibson 5 by 2030, Cayuga 2 by 2031.
- Add 450 MW of solar and 425 MW of battery energy storage by 2030, 1,438 MW of advanced class CCs by 2031.







Exit Coal Earlier (Stakeholder) Generation Strategy

As part of the stakeholder engagement process for the 2024 IRP, Duke Energy Indiana developed the Exit Coal Earlier (Stakeholder) generation strategy over several months in collaboration with a stakeholder group.

This strategy is very similar to Blend 1, with conversion of the Cayuga steam units to 100% natural gas fuel and retirement of all Gibson units, but the timeline is more aggressive. The Cayuga conversion to natural gas is completed by 2029, one year in advance of the deadline under the EPA CAA Section 111 Rule, and Gibson units 3, 4 and 5 are retired by 2030. Consistent with Blend 1, Gibson units 1 and 2 are retired by 2032, and Edwardsport is converted to natural gas by 2030.

The accelerated retirement of Gibson units 3 and 4 necessitates additional new resource deployment in the 2020s, and the Reference Case portfolio for the Exit Coal Earlier (Stakeholder) strategy includes 550 MW of solar, 675 MW of battery energy storage, and 719 MW of advanced class CC capacity added by 2030. An additional 1,438 MW of CC capacity are added by 2032, coinciding with the retirement of Gibson units 1 and 2.

This more aggressive approach to the energy transition in the near term carries elevated execution risk and results in the highest near-term increase in customer bills, but the total cost over the planning period is similar to that of the blend strategies.

The Exit Coal Earlier (Stakeholder) strategy is illustrated in Figure 4-13 below.

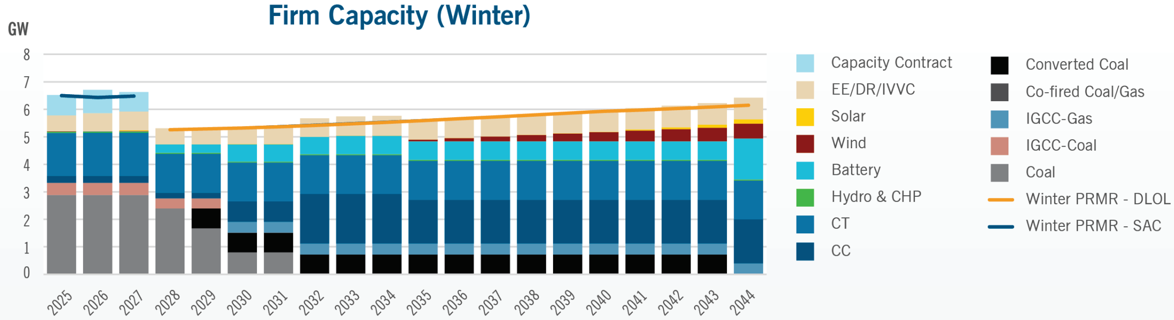
Figure 4-13: Exit Coal Earlier (Stakeholder) Generation Strategy Summary

Exit Coal Earlier (Stakeholder)

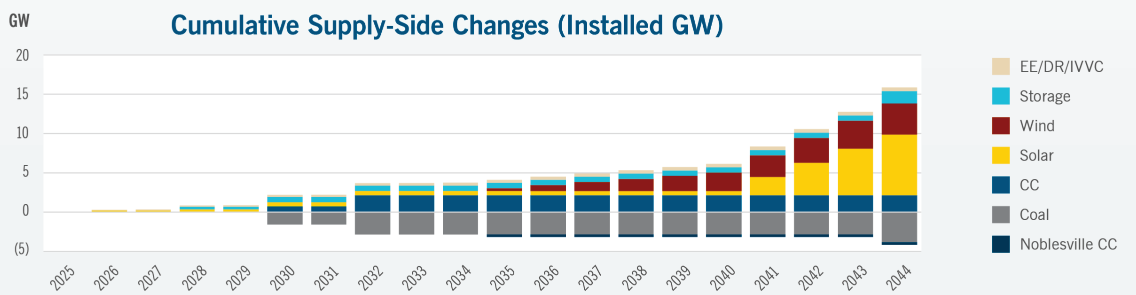
Customer Affordability Metrics	
PVRR ($B)	$24.3
Bill Impact (CAGR) 2030	4.3%
Bill Impact (CAGR) 2035	3.1%

- Convert Cayuga 1 & 2 to 100% natural gas fuel by 2029, retire Gibson 3-5 by 2030, in advance of deadlines under EPA CAA Section 111 Rule.
- Retire Gibson 1 & 2 by 2032, convert Edwardsport to natural gas by 2030 in compliance with EPA CAA Section 111 Rule.
- Add 550 MW of solar, 675 MW of battery energy storage, and 719 MW of CC by 2030, additional 1,438 MW of CC by 2032.

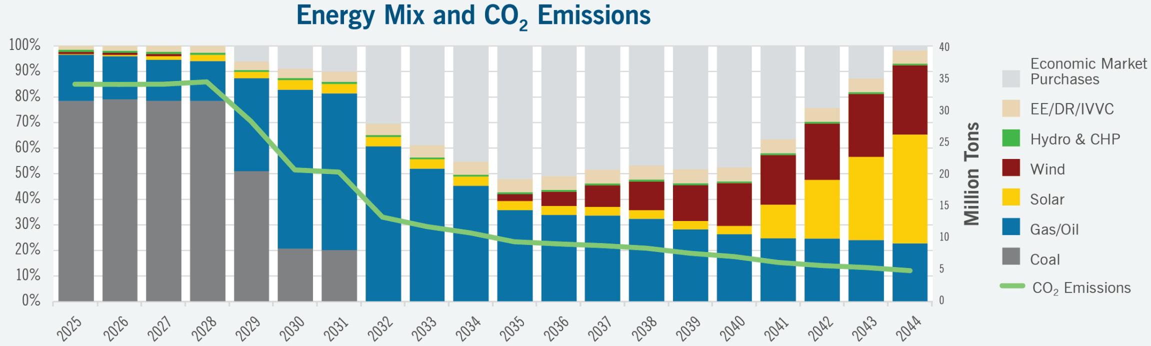
Firm Capacity (Winter)



Cumulative Supply-Side Changes (Installed GW)



Energy Mix and CO_2 Emissions



"No 111" Strategy Variation

In addition to the 111-compliant generation strategies, the Company also developed a strategy variation to explore the possibility that the EPA CAA Section 111 Rule is repealed. As such, this variation does not include mandated dates for unit retirements or conversions or a regulatory capacity factor limit on new natural gas resources. All other Reference Scenario assumptions hold.

It would still be reasonable and prudent in a "No 111" future for the Company to retire the Cayuga units by 2030 and 2031 and Gibson Unit 5 by 2030. The two advanced class 1x1 CCs that replace the Cayuga coal units provide incremental capacity, reliability gains, and risk mitigation that are advantageous in any of the futures evaluated in the 2024 IRP. Similarly, Gibson units 3 and 4 would be retired by 2032 and replaced with an additional advanced class CC, but a "No 111" future would allow flexibility to check and adjust the timing of that decision if conditions change. Finally, solar (299 MW) and battery energy storage (500 MW) would still be required to meet near-term energy and capacity needs.

Without the requirements of the EPA CAA Section 111 Rule, the Company would be able to continue to operate Gibson units 1 and 2 on coal beyond 2032, reducing costs for customers. These units could reasonably be retired by the end of 2035 while preserving customer affordability. Similarly, the Company could preserve the flexibility and optionality offered by the dual fuel Edwardsport IGCC. Without the EPA CAA Section 111 Rule, CO_2 emissions continue to decrease over time, albeit at a slower rate of decline compared to 111-compliant generation strategies.

The analytical results for the "No 111" strategy variation indicate that it would have lower costs, both in terms of near-term customer bill impacts and total costs over the planning period, than any of the 111-compliant cases.

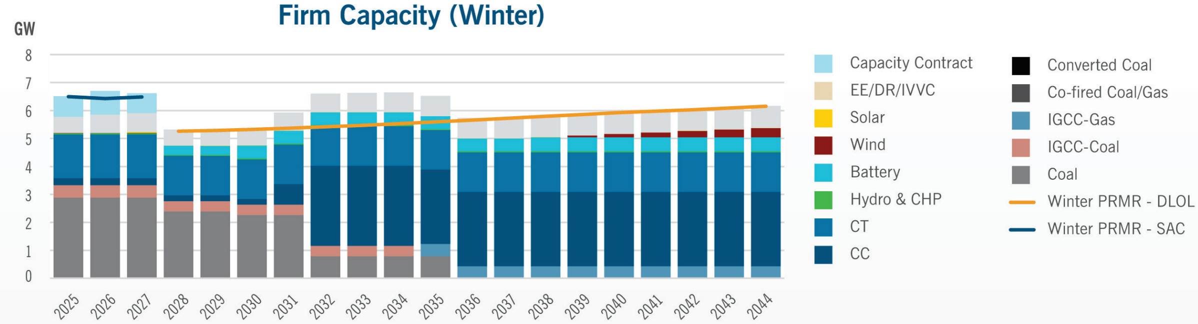
Figure 4-14 below presents a summary of the "No 111" case.

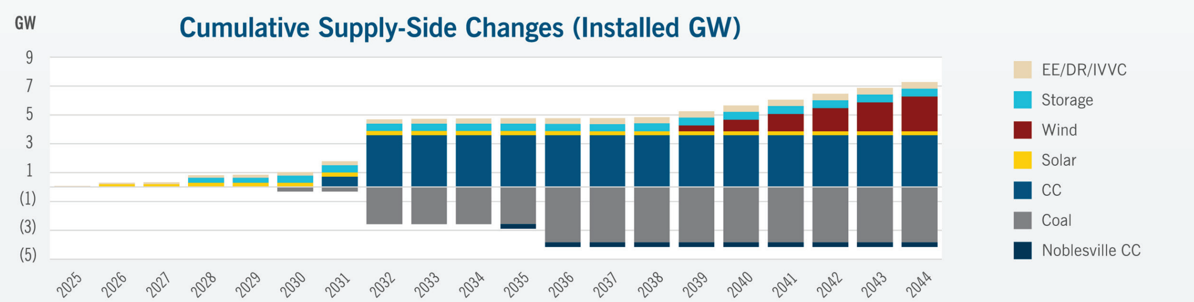
Figure 4-14: No 111 Strategy Variation Summary

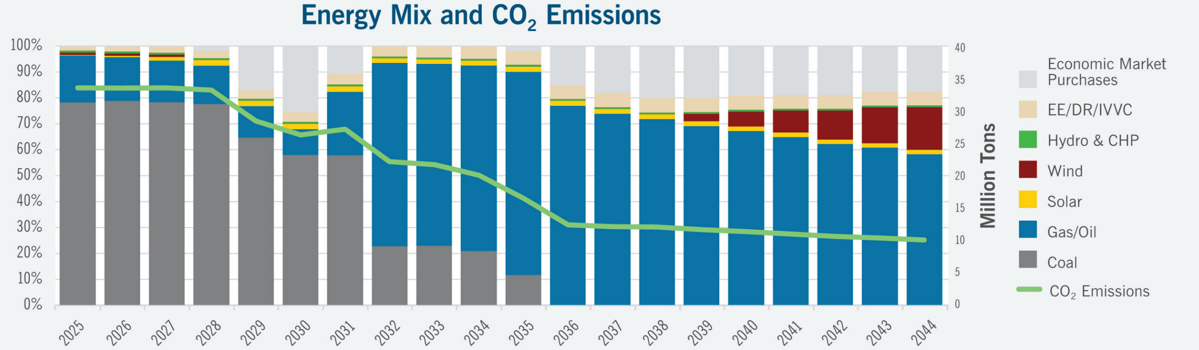
No 111

Customer Affordability Metrics	
PVRR ($B)	$23.2
Bill Impact (CAGR) 2030	3.7%
Bill Impact (CAGR) 2035	2.4%

- Retire Cayuga 1 & 2 by 2032.
- Retire Gibson 5 by 2030, Gibson 3 & 4 by 2032, and Gibson 1 & 2 by the end of 2035.
- Convert Edwardsport to natural gas fuel by the end of 2034.
- Add 299 MW of solar, 500 MW of battery energy storage by 2030, 3,595 MW of advanced class CCs by 2032.







Portfolio Comparison & Evaluation

The following section provides a comparative evaluation of results across the six generation strategies including portfolio performance and trade-offs with respect to the planning objectives outlined in Chapter 2. Table 4-2 below provides a summary of scorecard results across for the generation strategies in the Reference Case, offering a high-level summary of relative trade-offs among portfolios. This summary is complemented by a more detailed comparative discussion of the generation strategies following the scorecard summary.

The individual scorecard metrics are defined in Chapter 2 and details on their calculation are provided in Appendix C.

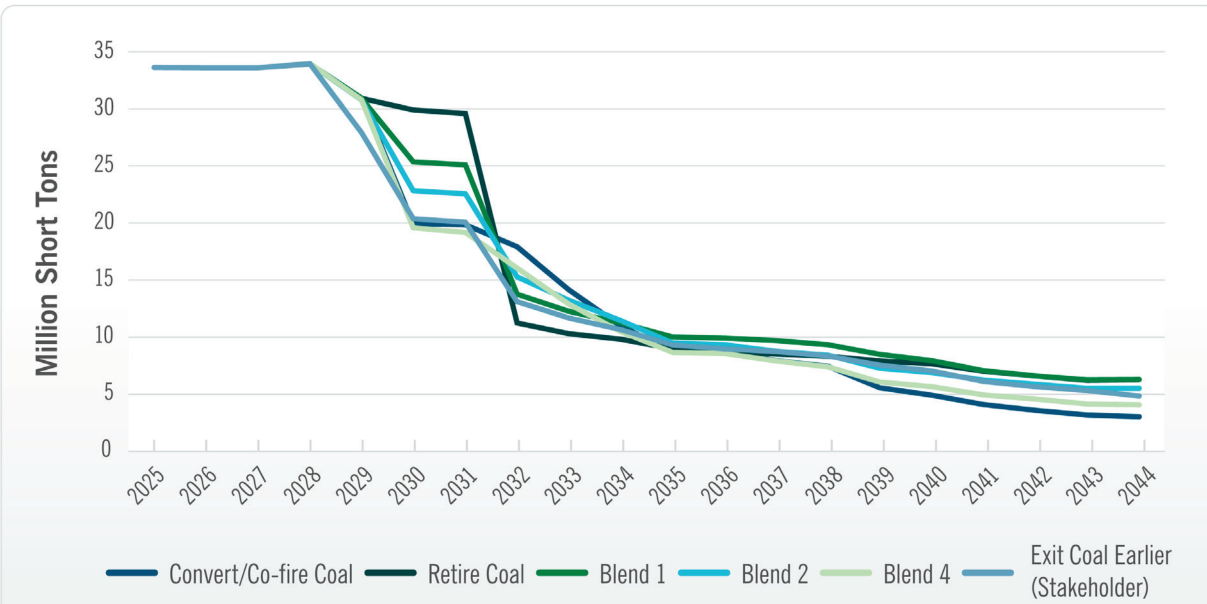
Table 4-2: Summary of Portfolio Scorecard Results

Portfolio Scorecard			Convert/Co-Fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier (Stakeholder)
Environmental Sustainability	CO_2 Emissions Reduction	2035	74%	73%	70%	72%	74%	72%
		2044	91%	81%	81%	84%	88%	86%
	Cumulative CO_2 Reduction (Mt)	2044	367	340	337	348	367	362
	CO_2 Intensity of Duke Energy Indiana Portfolio (lbs./MWh)	2035	715	572	710	678	666	652
Affordability	PVRR ($B)	2044	$25.0	$23.6	$24.2	$24.3	$24.5	$24.3
	Customer Bill Impact (CAGR)	2030	3.9%	3.7%	3.9%	4.0%	4.0%	4.3%
		2035	3.1%	3.3%	2.8%	3.1%	2.9%	3.1%
Reliability	Fast Start Capability	2035	39%	31%	33%	33%	33%	38%
	Spinning Reserve Capability	2035	93%	93%	98%	102%	100%	87%
Resiliency	Resource Diversity (HHI)	2035	1766	3853	2802	2739	1758	2291
	Simulated EUE in 95th Percentile Cold Weather (Islanded System)	2035	2.8%	1.9%	0.9%	1.4%	2.1%	3.7%
Cost Risk	Cost Variability Across Scenarios ($B)	2044	$24.0-$28.1	$21.8-$26.8	$22.4-$27.2	$22.9-$26.9	$23.3-$27.8	$23.4-$27.2
	IRA Exposure	2030	81%	43%	81%	50%	49%	57%
		2035	81%	29%	20%	22%	33%	39%
Market Exposure	Fuel Market Exposure	Average	61%	72%	76%	72%	66%	70%
	Maximum Energy Market Exposure	Annual Max.	69%	43%	51%	53%	66%	52%
Execution Risk	Cumulative Resource Additions in MW	2030	1,037	1,656	1,037	1,856	1,831	2,181
		2035	1,823	5,568	4,049	4,149	2,686	4,105
	Cumulative Resource Additions as % of Current System	2030	13%	20%	13%	23%	23%	27%
		2035	22%	69%	50%	51%	33%	51%

Environmental Sustainability: CO_2 Emissions & Intensity

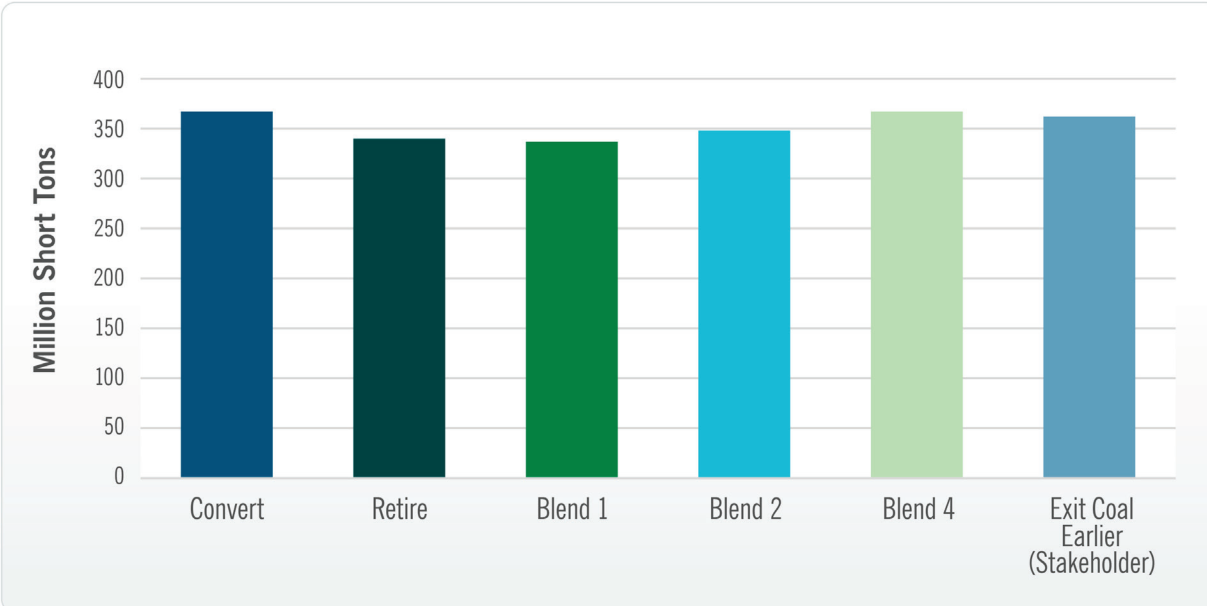
CO_2 emissions are highly correlated with other factors related to the environmental sustainability of the resource mix and are used as a representative indicator in this portfolio evaluation. Because Duke Energy Indiana's participation in the MISO energy market can sometimes mask the emissions associated with the Company's own portfolio, both total CO_2 emissions and CO_2 emissions intensity of Company resources are included in this assessment. The total CO_2 emissions metric includes estimated emissions associated with market energy purchases. Figure 4-15 below shows projected annual CO_2 emissions for each generation strategy in the Reference Scenario.

Figure 4-15: Annual CO_2 Emissions



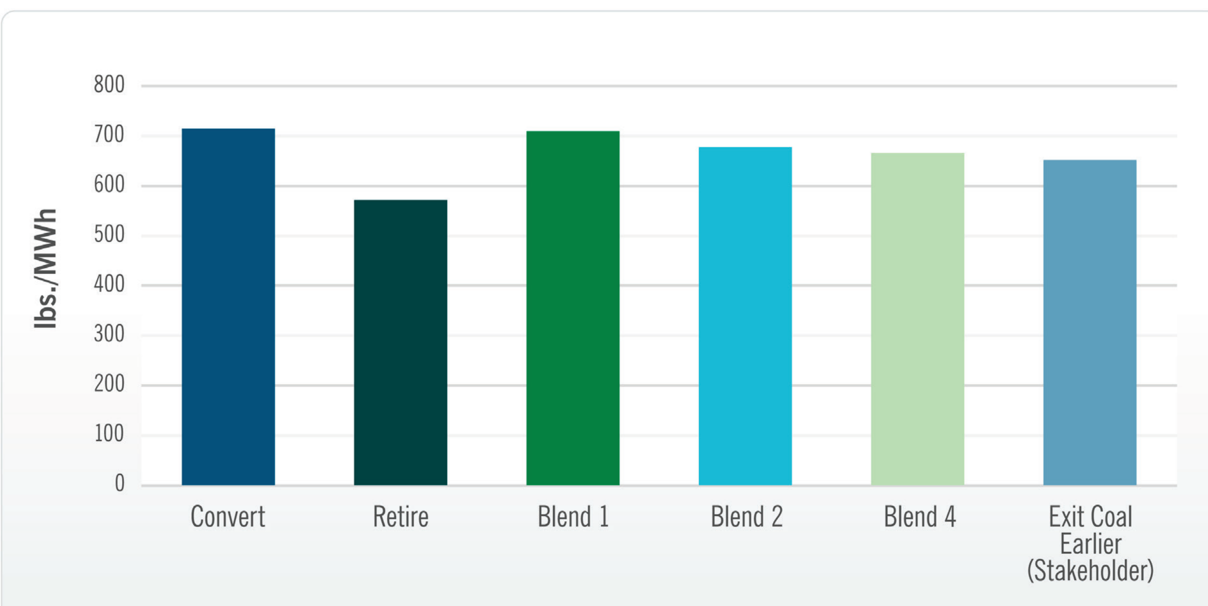
Projected CO_2 emissions for the six generation strategies follow the same general pattern, declining steeply in the early 2030s as coal units are retired or converted to burn either 100% natural gas or a blend of natural gas and coal (co-firing). Emissions continue to decline through the second half of the planning period, albeit at a more moderate pace, as the growing contribution from renewables displaces energy purchased from the MISO market. Ultimately, all strategies result in substantial reductions in CO_2 emissions by 2044. Figure 4-16 below shows the cumulative reduction in CO_2 emissions for each generation strategy in the Reference Scenario over the 20-year planning horizon.

Figure 4-16: Cumulative CO_2 Emissions Reduction, 2025-2044



CO_2 intensity of the Duke Energy Indiana portfolio is directly correlated with the retirement or conversion of existing coal units. CO_2 intensity (pounds per megawatt-hour ("MWh") generation) of the Company's portfolio is higher for strategies that retain existing steam units than for strategies in which coal units are retired and replaced with efficient, low-carbon advanced class CCs. Figure 4-17 below illustrates the CO_2 intensity of each generation strategy in the Reference Scenario in 2035.

Figure 4-17: 2035 CO_2 Intensity of Duke Energy Indiana Portfolio Resources (lbs./MWh)

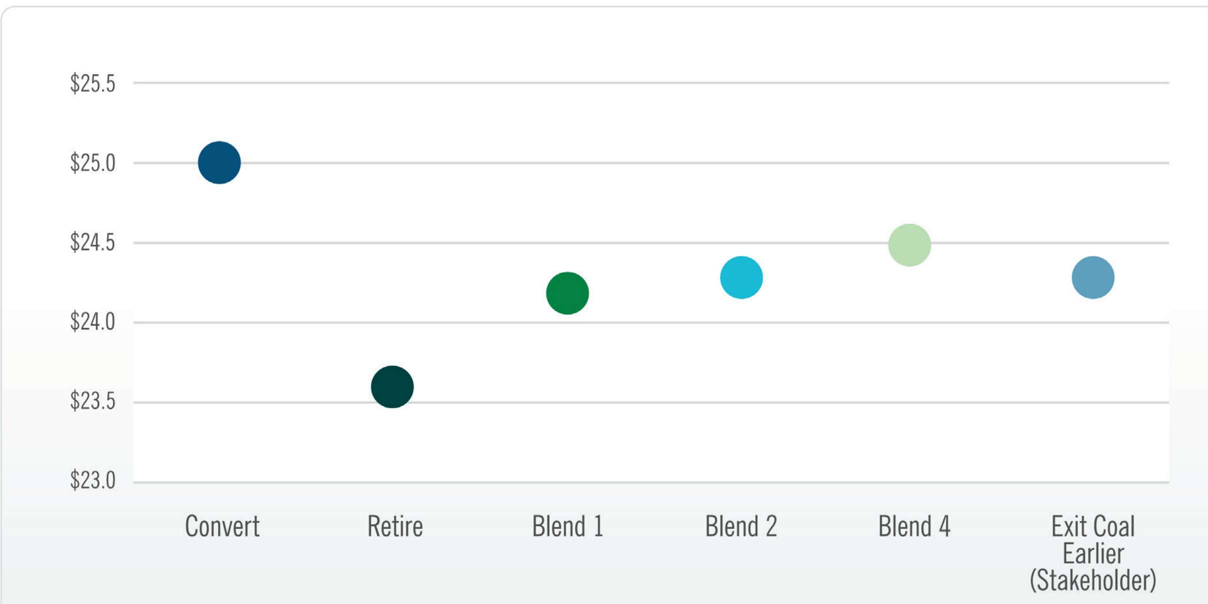


Affordability: Present Value of Revenue Requirements & Customer Bill Impact

Duke Energy Indiana uses two metrics to gauge relative cost across generation strategies. PVRR provides an estimate of total cost over the planning period. Projected customer bill compound annual growth rates ("CAGR") by certain specified years provides estimates of cost impacts at snapshots in time. In both cases, cost estimates are IRP-specific and useful for comparative evaluation only. Chapter 2 provides additional detail on cost metrics.

Figure 4-18 below presents the PVRR of each generation strategy in the Reference Scenario. As discussed previously in this Chapter, the Retire Coal strategy yields the lowest total cost over the planning period, while Convert/Co-fire Coal results in the highest total cost. Costs across the blend strategies and Exit Coal Earlier (Stakeholder) are very similar on a PVRR basis.

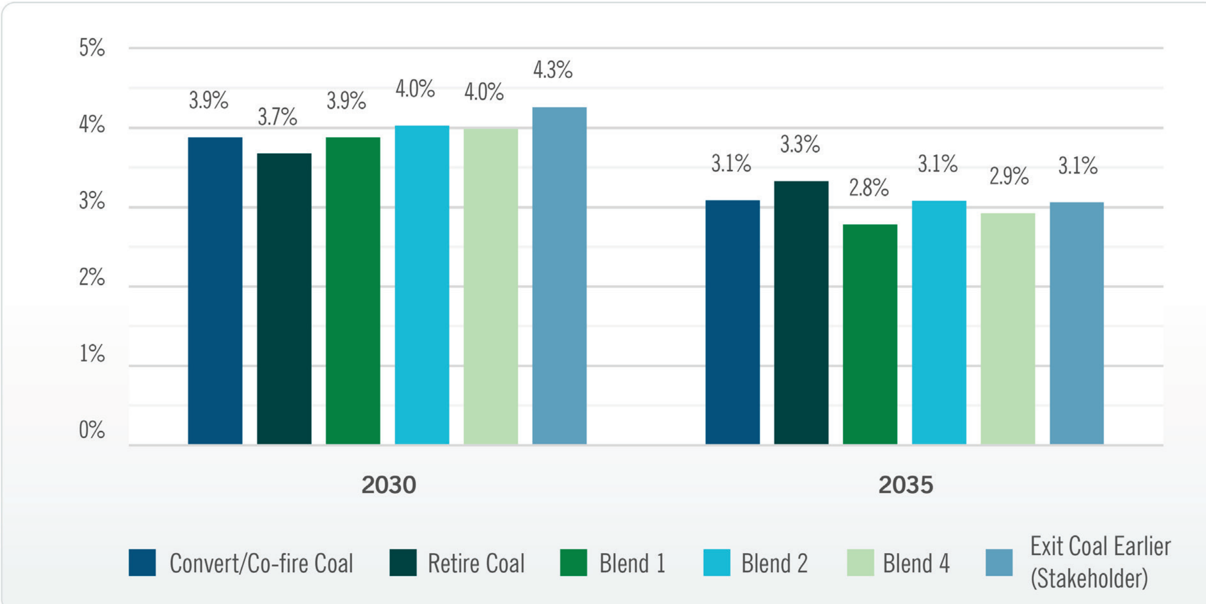
Figure 4-18: PVRR by Generation Strategy ($B)



Note: IRP PVRR calculations do not consider depreciation of existing assets, other non-avoidable costs, or costs not related to resource planning, and are useful for portfolio comparison only.

The projected customer bill impact results indicate that there are trade-offs between total cost over the planning period (PVRR) and near-term impacts to customers (bill CAGR). The Retire Coal strategy, the strategy with the lowest PVRR, results in the highest projected customer bill CAGR through 2035, the middle of the planning period. The blend strategies achieve more balance between near-term and long-term cost impacts.

Figure 4-19: Customer Bill Impact (CAGR) by Generation Strategy



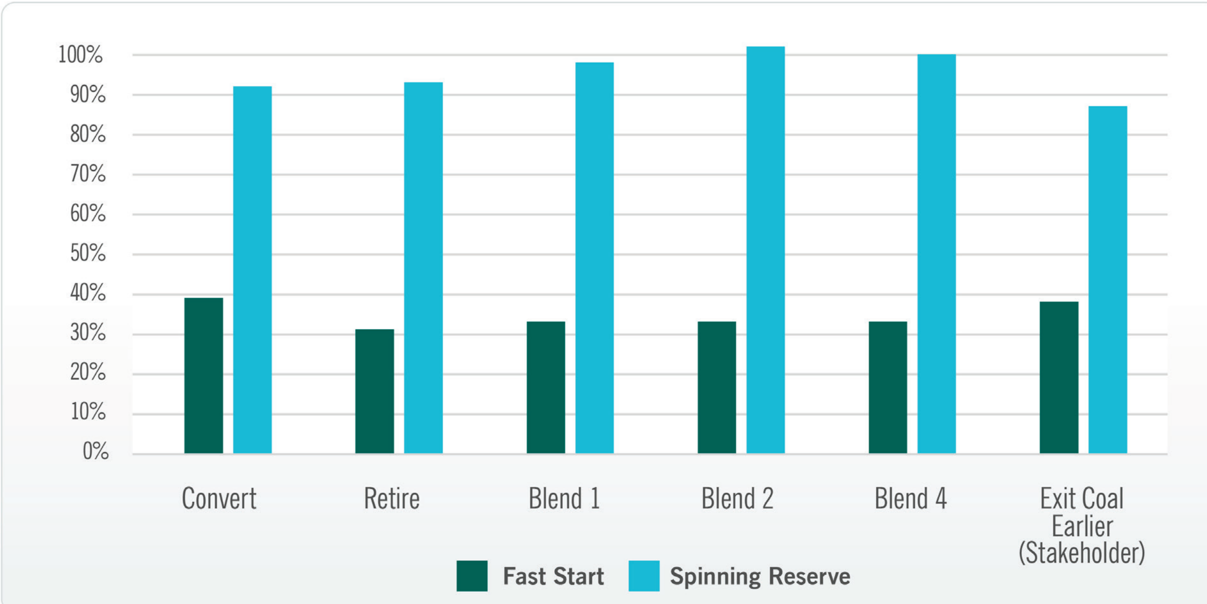
Note: IRP bill impacts for typical residential household using 1,000 kWh/month exclude depreciation of existing assets, other non-avoidable costs, and costs not related to resource planning. IRP bill impact projections are useful only for relative comparison of portfolios.

Reliability: Fast Start & Spinning Reserve Capability

Maintaining or improving reliability is a core mandate for resource planning. The EnCompass capacity expansion model ensures that all portfolios developed for the 2024 IRP meet MISO seasonal planning reserve margin requirements. As variable, weather-dependent resources contribute a larger share of total system energy, additional measures of system reliability and flexibility will become increasingly important. Fast start and spinning reserve capabilities are essential to maintaining reliable service through fluctuations in generation and in customer demand. Appendix E (Reliability and Resource Adequacy) provides a detailed discussion of system reliability.

Figure 4-20 below shows fast start (CTs and batteries) and spinning reserve (steam units, CCs, CTs, combined heat and power ("CHP"), and hydro) capacity by generation strategy as a percentage of coincident peak load. The Company selected 2035 as the representative year because it is in the middle of the planning period, after the substantial changes of the early 2030s have been completed. The results across generation strategies do not diverge dramatically, but Figure 4-20 does illustrate some trade-offs between fast start (more battery capacity) and spinning reserve (more steam units and CCs).

Figure 4-20: Fast Start Capability and Spinning Reserve (%) in 2035

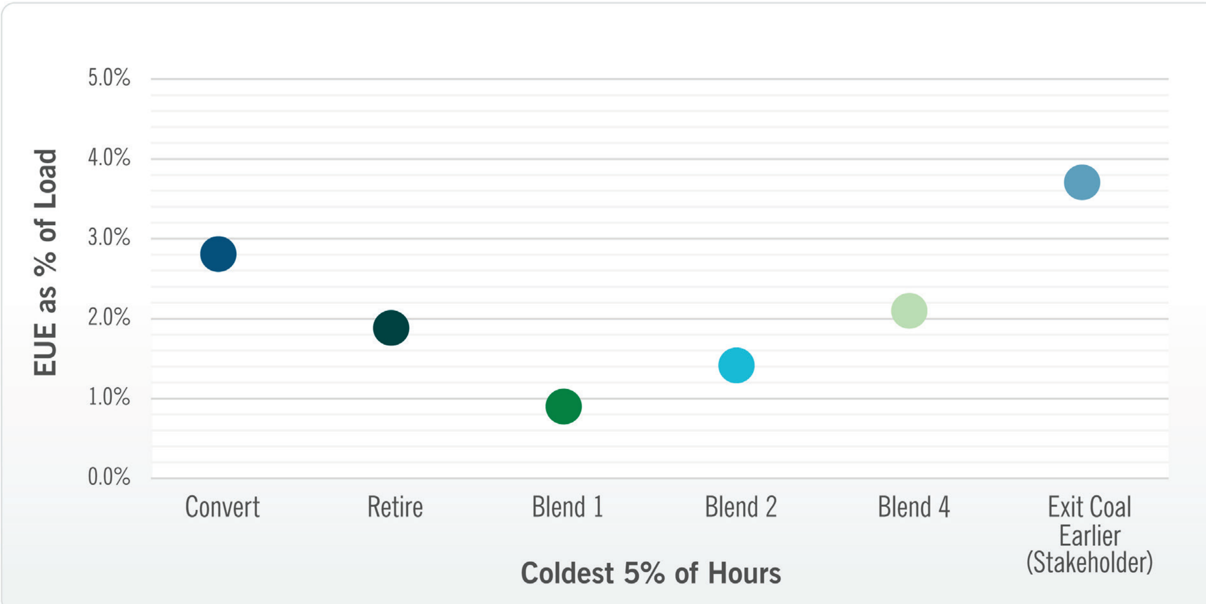


Resiliency: Portfolio Diversity & Cold Weather Performance

Duke Energy Indiana includes two measures of resiliency in the 2024 IRP. The first, portfolio diversity, provides an indication of the ability of the portfolio to serve customers under a variety of different weather and market conditions. Each resource and fuel type has its own strengths and risks, and a diverse portfolio ensures that those risks are prudently diversified. The Herfindahl-Hirschman Index ("HHI") results presented in the scorecard indicate that each generation strategy has a diversified resource mix. (A portfolio with only one resource type scores an HHI result of 10,000, with lower values indicating greater diversification).

The second measure of resiliency is simulated expected unserved energy ("EUE") in cold weather conditions. For this calculation, the Company used the SERVM model to conduct EUE simulations for its system on an islanded basis, meaning without connection to the broader MISO system, across thousands of unit outage and economic conditions during the coldest 5% of hours. The Company used 2035 as the study year for each generation strategy, as it did for other metrics. In this case, EUE indicates periods of potential reliance on the broader MISO market to reliably serve customers. Figure 4-21 below presents simulated EUE as a percentage of total load in 2035.

Figure 4-21: 2035 Simulated EUE as a Percent of Load in Coldest 5% of Hours

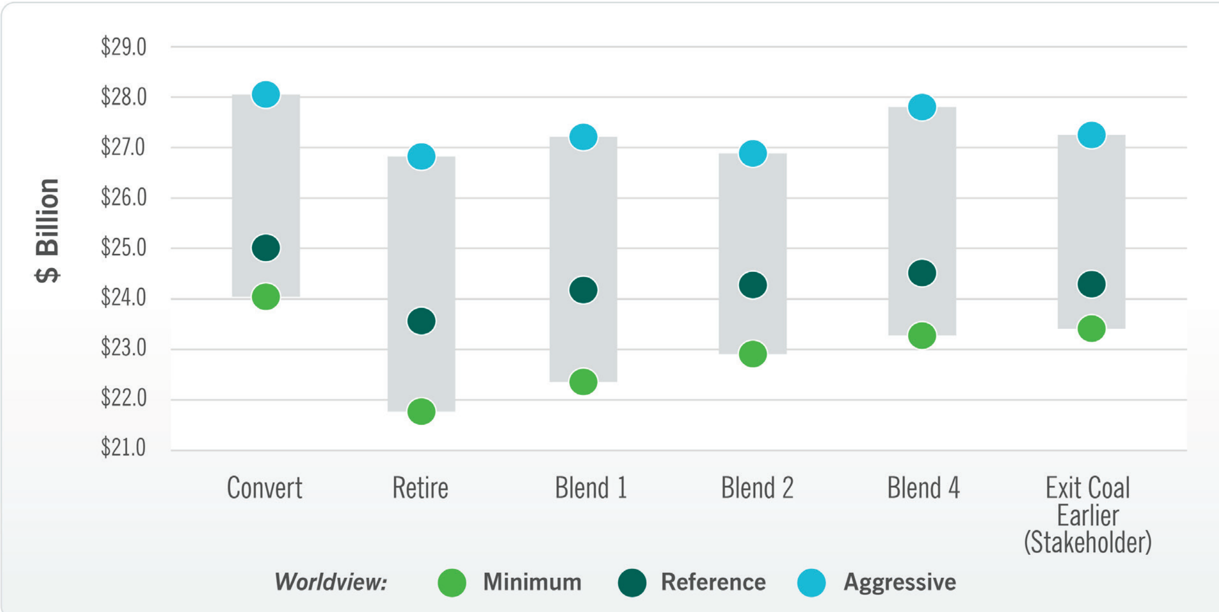


As Figure 4-21 above shows, Blend 1 and Blend 2 strategies have the lowest percent of EUE in the test year. A combination of new CCs and a balanced mix of other resources contribute to system resiliency during the coldest parts of the year. Stochastic analysis of cold weather risk is discussed in more detail later in this Chapter.

Cost Risk: PVRR Results Across Planning Scenarios & Exposure to Federal Tax Credits

While the Reference Scenario is comprised of the base case forecasts and assumptions for all IRP inputs, the Aggressive and Minimum worldviews represent plausible alternate futures. The range of PVRR results across the planning scenarios provides an indication of cost risk should future conditions deviate from Reference assumptions. As the PVRR ranges in Figure 4-22 below illustrate, the Convert/Co-fire Coal strategy results in the highest total cost to customers across all planning scenarios, reflecting the ongoing costs of continued reliance on aging assets. The Retire Coal strategy yields the lowest total cost across all scenarios, reflecting the flexibility that strategy provides to retire aging assets and replace them with a mix of resources best suited to the conditions of any given future. That theme is reflected in results for the other strategies, with Blend 1 and Blend 2 also offering flexibility to adapt to changing conditions.

Figure 4-22: Cost Risk ($B) by Generation Strategy

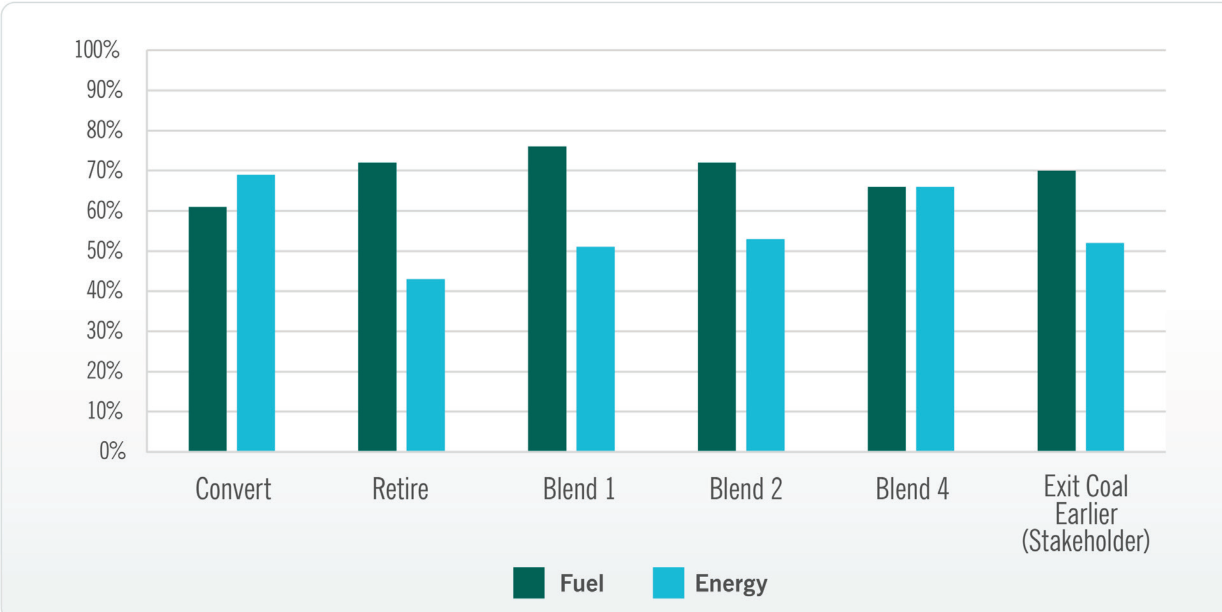


The Inflation Reduction Act of 2022 ("IRA") offers investment and production tax credits to incentivize deployment of low- and zero-carbon technologies. Chapter 3 describes the Company's planning assumptions related to tax credits in detail. The Company's Reference Case assumption is that IRA tax credits persist throughout the planning period. However, this is not a certainty, and reliance on IRA tax credits is a potential cost risk. The portion of new resource capacity added by 2030 and 2035 that benefits from IRA tax credits is included as a cost risk metric in the scorecard (Table 4-2 above). These results indicate that the Convert/Co-fire coal strategy carries the greatest IRP exposure on a proportional basis.

Market Exposure: Power & Fuels

Although each of the candidate resource portfolios the Company developed for the 2024 IRP would be capable of serving customers' expected future needs, the generation strategy results presented previously in this Chapter illustrate the extent to which economic participation in the MISO energy market may provide low-cost energy. The expected contributions from the MISO energy market are based on forecasted energy prices, and therefore carry a certain amount of cost risk. Similarly, potential variation around the Company's fuel price forecasts also creates cost risk. Fuel prices are a major driver of power prices, so these risks are correlated. Figure 4-23 below illustrates the energy and fuel market exposure of each generation strategy.

Figure 4-23: Fuel and Energy Market Exposure

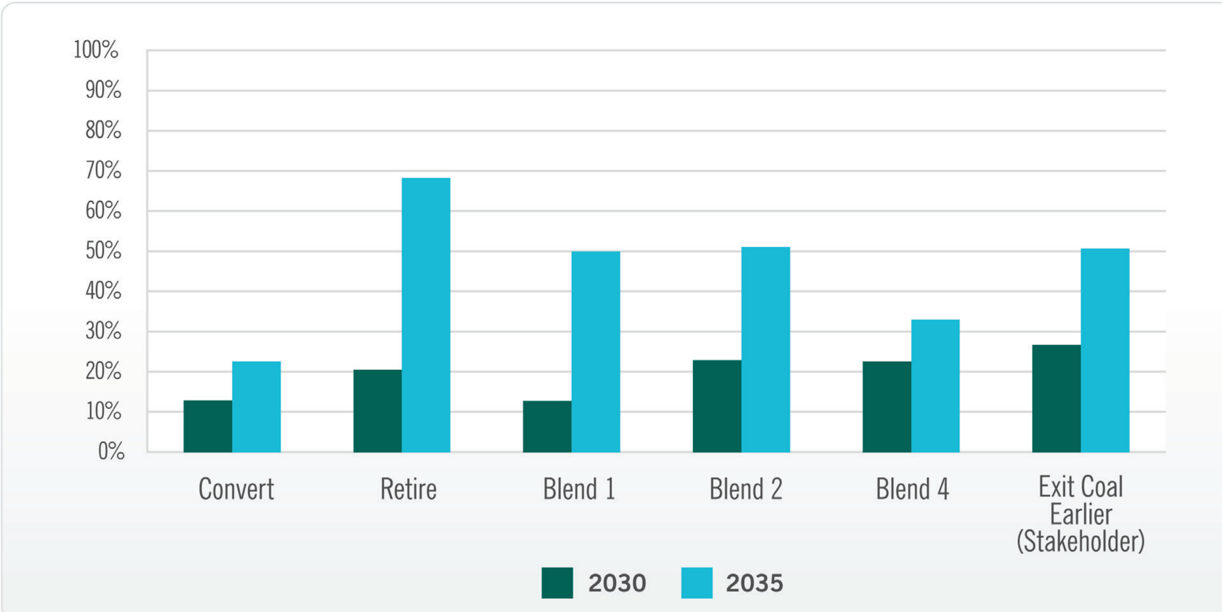


Energy market exposure is particularly acute in the mid-2030s and is presented as maximum energy market exposure in any single year (2035 for all strategies but Blend 1, for which exposure is greatest in 2036). Fuel market exposure persists over the planning period and is therefore presented on an annual average basis. Blend 1 carries the highest fuel market exposure, while Convert/Co-fire Coal carries the highest exposure to the MISO energy market. The Company also performed stochastic analysis to further explore market risk. This analysis is discussed later in this Chapter.

Execution Risk

The Preferred Portfolio identified in the IRP serves as the basis for near-term actions to advance the plan and as such must be executable in the real world. For this reason, execution risk is a key consideration in identifying the Preferred Portfolio. Each of the generation strategies considered in the 2024 IRP requires the addition of over 1,000 MW of new resources over the next decade, but the scale of resource additions varies considerably across strategies as a characteristic of the pace of change. The cost metrics used in this comparative evaluation of the generation strategies illustrate the trade-off between lowering total costs over the planning period and mitigating near-term customer bill impacts. Execution risk is another important consideration, especially with respect to strategies that contemplate a more rapid transition. The Preferred Portfolio must allow sufficient time for procurement, permitting, construction, and interconnection of new resources. Figure 4-24 below illustrates the scale of new resource additions required for each generation strategy by 2030 and 2035, presented as a percentage of the total capacity of the Duke Energy Indiana system today. The scorecard, shown in Table 4-2 above, provides these results in MW terms.

Figure 4-24: Cumulative Resource Additions as Percent of Current System



Relative execution risk across strategies is related to relative customer bill impact. Exit Coal Earlier (Stakeholder) requires the most substantial new resource additions by 2030 and also results in the highest customer bill impact by 2030. Similarly, Retire Coal requires the most additional capacity (in MW) by 2035 and results in the highest customer bill impact by that time. Both customer bill impact and plan execution risk are important factors contributing to the selection of the Preferred Portfolio.

Summary of Portfolio Evaluation

The Duke Energy Indiana 2024 IRP explores a diverse set of options and pathways for transitioning the existing coal fleet in compliance with existing regulations. However, certain trends emerged across all generation strategies. First, dispatchable thermal resources provide the foundation for system reliability throughout the planning period. Second, renewables and battery energy storage are required to meet growing demand in the 2020s. Third, economic energy purchases from the MISO market help maintain affordability for customers during the mid-2030s. Finally, the economics for renewable energy resources steadily improve over the planning period, and sizable quantities of renewables are added in the second half of the planning period across all generation strategies.

The key differentiator across generation strategies lies in the compliance pathways for existing coal units under the EPA CAA Section 111 Rule. This analysis evaluated various combinations of conversions – either to 100% natural gas or 50% co-firing – and retirements to determine which pathway best satisfies the IRP planning objectives described in Chapter 2.

Generation strategies that retire coal units typically replace that dispatchable resource with new highly efficient CC units. These new CC units not only provide efficient, low-emission sources of energy and capacity but also add incremental capacity relative to the resource being replaced. For example, Blend

2 and Blend 4 retire Cayuga units 1 and 2, replacing them with two 1x1 CCs, which add an incremental 440 MW of capacity by 2031. Conversely, strategies that convert existing coal units do not add incremental capacity at existing sites and instead rely on battery energy storage earlier in the planning period to meet incremental capacity requirements.

Among the generation strategies that convert coal units, there are notable differences between 100% natural gas conversion and conversion to 50% co-firing. A unit converted to 100% natural gas remains online throughout the planning period, continuing to support system reliability by providing dispatchable capacity. A co-fired coal unit also provides capacity but must retire by 2039 under the EPA CAA Section 111 Rule. In either case, legacy steam units struggle to be economically competitive in the MISO market and generate little energy beyond the early 2030s.

Recognizing that resource planning is an iterative process, the Company will have future opportunities to “check and adjust” as policies evolve, new technological developments occur, and more refined information becomes available. As the Company moves forward with the activities specified in the Short-Term Action Plan described in Chapter 6 (Short-Term Action Plan), the timelines and costs assumed in IRP modeling will either be validated or challenged by real-world experience. New information will be used to refine generation strategies and advance the Company’s planning objectives in future IRPs.

Sensitivity Analysis

Duke Energy Indiana conducted sensitivity analysis to assess the extent to which analytical results change in response to changes in individual input variables. This is complementary to the scenario analysis, in which multiple variables are changed at once to evaluate alternate planning futures. The Company conducted both portfolio sensitivity analysis, evaluating changes to resource selection, and production cost sensitivity analysis, evaluating changes to portfolio operating costs, leveraging the Reference Scenario as the base case. The analytical framework is described in detail in Chapter 2, and results of these analyses are presented in more detail below as well as in Appendix C.

Portfolio Sensitivity Analysis

In the portfolio sensitivity analysis step, Duke Energy Indiana evaluated changes to resource selection in response to changes in the cost of new CCs, alternate load forecasts, and an alternate resource accreditation methodology.

Portfolio Sensitivity Analysis: Resource Capital Cost

Duke Energy Indiana conducted capital cost sensitivity analysis to assess the potential impacts of continued cost increases on resource selection. The Company focused on new CC and CT resources for this analysis because they provide the dispatchable capacity that is essential to allow the retirement of aging coal units and support growing contributions from variable energy resources. Although the Company changed only the cost of CCs and CTs for this analysis, it is reasonable to expect that the underlying factors contributing to potential changes in CCs costs (e.g., the cost of labor or raw materials) would also affect the costs of other resource types.

The Company developed new Reference Case portfolios for each generation strategy using a capital cost forecast for new CC and CT resources that was 60% higher than the base forecast. The resulting changes to CC capacity selected for each portfolio are shown in Table 4-3 below. Importantly, even at 1.6 times the base cost forecast, at least 1,438 MW, the equivalent of two 1x1 CCs or one 2x1 CC, are selected in all but two generation strategies.

Table 4-3: Combined Cycle Additions by 2035 (MW)

Strategy	Reference Case	High CC Cost	Change from Ref.
Convert/Co-fire	-	-	-
Retire Coal	3,595	2,876	(719)
Blend 1	2,876	1,438	(1,438)
Blend 2	2,876	1,438	(1,438)
Blend 4	1,438	-	(1,438)
Exit Earlier (Stakeholder)	2,157	1,438	(719)

Portfolio Sensitivity Analysis: Load Forecast

Future load growth may trend higher or lower than the base case forecast for a variety of reasons. The load forecast is of foundational importance to the resource plan. Therefore, evaluating the potential effects of variations in the load forecast (both higher and lower) on resource selection is an essential component of the IRP. For this sensitivity analysis, the Company evaluated a high load case and a low load case. The details of these alternate forecasts are provided in Appendix D (Load Forecast). In addition to the more rapid economic development underpinning the high load forecast, that case includes an incremental 500 MW of data center load by 2031.

The results of the high load analysis indicate that if load increases at a faster rate than expected in the base forecast, new resources will similarly need to be added to the system more rapidly. Table 4-4 below provides the amount of new resource capacity (in installed MW) that would need to be added by 2035 incremental to the amounts included in the Reference Scenario resource portfolios for each generation strategy.

Table 4-4: Additional Resources Required in High Load Case by 2035 Relative to Reference Scenario (MW)

Generation Strategy	CC	Solar	Wind	Storage
Convert/Co-fire Coal	+719	+1,200	+400	+900
Retire Coal	+719	+1,950	+1,450	+725
Blend 1	+719	+1,000	+1,200	+650
Blend 2	+1,438	+1,000	+300	+900
Blend 4	+1,438	+1,100	+550	+875
Exit Coal Earlier (Stakeholder)	+1,438	+1,000	+1,200	+900

As Table 4-4 above illustrates, greater amounts of all resource types are required in all strategies. In a high load future like the one evaluated here, it could be necessary to retain more existing MW than otherwise planned, while also adding substantial new capacity.

The Company also evaluated a low load case. In a future with lower customer demand than projected in the base forecast, new resource needs would be less. Table 4-5 below illustrates resource selection changes by 2035 in a low load future for each generation strategy, relative to the Reference Scenario.

Table 4-5: Resource Selection Changes in Low Load Case by 2035 Relative to Reference Scenario (MW)

Generation Strategy	CC	Solar	Wind	Storage
Convert/Co-fire Coal	--	(150)	+50	(400)
Retire Coal	(719)	+500	--	--
Blend 1	+719	(150)	+650	(175)
Blend 2	--	(200)	--	(200)
Blend 4	--	--	--	(250)
Exit Coal Earlier (Stakeholder)	--	--	(250)	(500)

As Tabe 4-5 shows, the low load case results in lower amounts of solar and battery energy storage selected for most generation strategies. Importantly, there is no change in the amount of CC capacity selected for most strategies, underscoring the importance of economically competitive, efficient, dispatchable capacity even in a lower load scenario.

Portfolio Sensitivity Analysis: Resource Accreditation Method

As MISO continues to reform its resource accreditation methodology, the Company updates its planning assumptions accordingly. In 2022, MISO moved to a seasonal accreditation standard (seasonal accredited capacity, or "SAC") under which member utilities must meet a specified planning reserve for winter, spring, summer, and fall rather than a single annual reserve margin. In early 2024, MISO filed an application with FERC to further refine SAC by implementing the DLOL methodology. The specifics of SAC and DLOL resource accreditation methods are discussed in Chapter 3.

MISO has proposed adopting the DLOL method starting in 2028, making this the appropriate standard for the 20-year IRP analysis. Nevertheless, the Company conducted sensitivity analysis to evaluate the impact of the capacity accreditation method on resource selection for each of the two bookend generation strategies (Convert/Co-fire Coal and Retire Coal). Table 4-6 below provides the changes to resource selection that result from using the SAC construct throughout the planning period.

Table 4-6: Changes to Resource Selection by 2035 and 2044 Using SAC Throughout the Planning Period, Relative to Reference Scenario (MW)

Strategy	CC	Solar	Wind	Storage
	Changes by 2035			
Convert/Co-fire Coal in Reference	--	349	350	750
► ***Change w/ SAC throughout***	*+719*	*+700*	*+500*	*+75*
Retire Coal in Reference	3,595	399	900	300
► ***Change w/ SAC throughout***	*(719)*	*+600*	*+900*	*+550*
	Changes by 2044			
Convert/Co-fire Coal in Reference	--	9,449	*3,750*	*2,050*
► ***Change w/ SAC throughout***	*+719*	*+200*	*+700*	*(750)*
Retire Coal in Reference	3,595	7,099	4,500	300
► ***Change w/ SAC throughout***	*(719)*	*+50*	*+900*	*+550*

Using the SAC method throughout the planning period results in relatively little change to CC capacity additions, and these are offset by changes to battery energy storage selection. Solar additions accelerate somewhat, but changes by 2044 are minor. Wind additions are higher using the SAC standard, which is consistent with the higher winter capacity value awarded to wind under that method. The reliability risk associated with growing reliance on variable energy resources is part of the impetus for accreditation reform, which supports the Company's assumption of DLOL resource accreditation for the 2024 IRP.

Production Cost Sensitivity Analysis

Production cost sensitivity analysis is the assessment of changes in portfolio operating costs under alternate variables and assumptions while holding portfolio composition constant. This analysis is performed using the EnCompass production cost model only.

Production Cost Sensitivity Analysis: Fuel Prices

Changes in fuel costs affect the cost of energy purchased from the MISO energy market as well as the cost of generation for Duke Energy Indiana. In this sensitivity analysis, the Company tested changes in PVRR and, importantly, changes in relative PVRR across generation strategies, in response to fuel price forecasts above and below the base forecast used in the Reference Scenario. The high and low fuel forecasts are described in detail in Appendix C. Figure 4-25 illustrates the PVRR changes across generation strategies in response to high and low fuel price forecasts. The results demonstrate that the six generation strategies are essentially equally sensitive to changes in fuel prices, with no significant change in relative PVRR across strategies.

Figure 4-25: PVRR Results for Alternate Fuel Price Forecasts ($B)

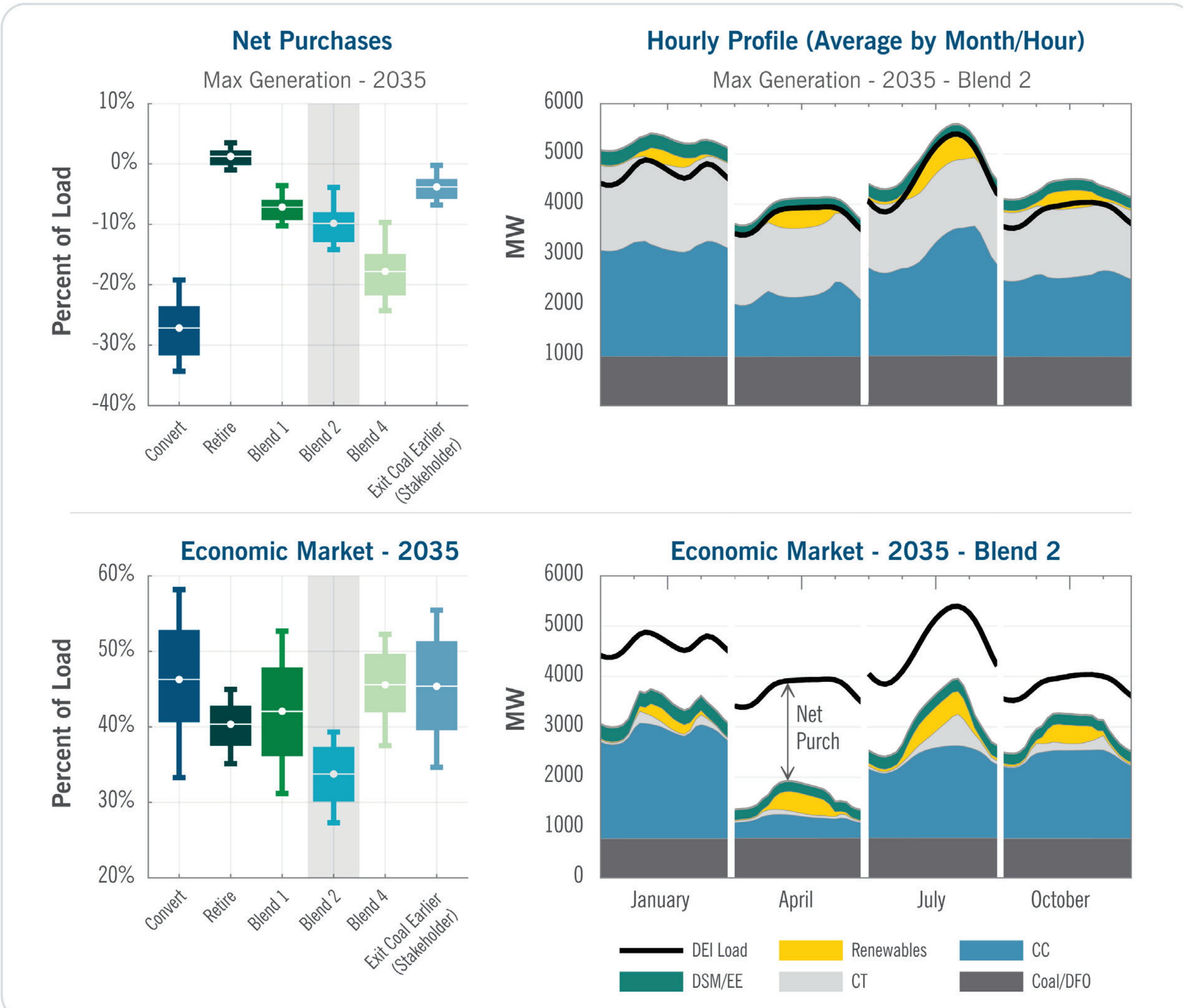
Insights from Stochastic Analysis

As discussed in Chapter 2, the 2024 IRP incorporates new stochastic analysis approaches that help explore and quantify selected reliability, market, and operational risks. For this analysis, each generation strategy was evaluated under the Reference Scenario. Each Reference Case portfolio has a different balance of resources, which in turn results in differing levels of exposure to fundamental market and operational uncertainties. The stochastic analysis exercises and evaluates the portfolios under a variety of correlated weather and market conditions. In contrast to the deterministic scenario and sensitivity analyses discussed above, stochastic models use historical uncertainty and forward market volatility to generate hundreds to thousands of simulations which vary key inputs, such as market prices, meteorology, loads and unit outages. The portfolios are dispatched in each of these simulations of future years to produce statistical distributions (averages and ranges around the average) of key metrics such as market reliance for reliability, market net purchases, operating costs, and emissions.

Market Operations & Energy Sufficiency Analysis

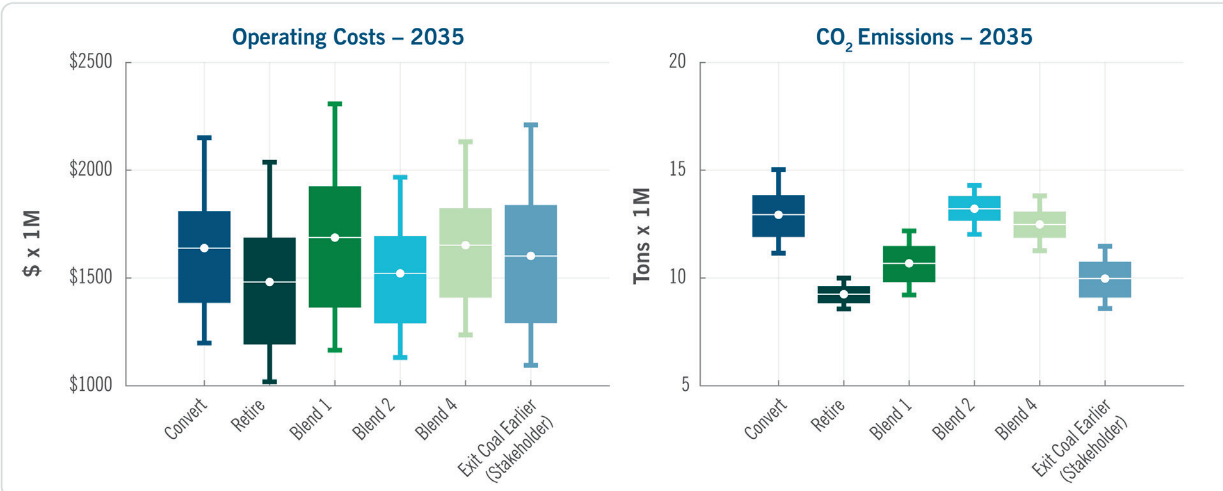
The Company ran hundreds of dispatch scenarios for the first set of stochastic analyses, assessing the portfolios for each generation strategy on dispatch in the context of the MISO market. Figure 4-26 below shows a comparison of net purchases in 2035 under both a *maximum generation* dispatch and an *economic market* dispatch. The maximum generation approach evaluates the portfolios for energy sufficiency by running thermal units at maximum capacity subject to outages and emission limits governed by EPA CAA Section 111 Rule. As shown in the top left panel, all generation strategies but Retire Coal deliver portfolios with the resources to meet annual average energy needs without relying on the MISO energy market (as evidenced by negative net purchases in the top left panel). In these box plots, the center line and dot represent the mean or average results across all simulations, the shaded box represents the 25th to 75th percentile (middle 50% of outcomes), and the whiskers represent the 10th-90th percentile ranges. The top right panel shows that the seasonal hourly energy profile exceeds loads for all hours for the Blend 2 portfolio in 2035. There is sufficient capacity and energy to serve load without undue reliance on the market. However, under normal mode of operations, the Company will participate in the market for economic benefits to reduce the cost to serve load for customers. In this case, as shown in the bottom two panels, under *economic market* dispatch, higher opportunistic purchase volumes are observed due to the favorability of market prices relative to generation costs of Duke Energy Indiana resources. In the lower right panel, the gap between total generation and load represents net average purchases which manifest as positive values in the lower left panel.

Figure 4-26: Stochastic Market Reliance and Economic Purchases



Economic participation in the market does subject the portfolios to cost risk due to volatility in market prices. While the average cost can be a useful metric to compare portfolios, the ranges produced from a stochastic analysis can provide additional context in understanding the uncertainty around those average projections. Figure 4-27 below shows the uncertainty from the stochastic analysis around operating costs and CO_2 emissions for study year 2035. Operating costs include stochastic cost to serve load, including production tax credits, as well as deterministic fixed costs. CO_2 emissions include both Duke Energy Indiana generating sources, as well as CO_2 from net market purchases.

Figure 4-27: Stochastic Operating Costs and CO_2 Emissions



Additional results from the stochastic analysis and detailed information on the stochastic modeling process are provided in Appendix C.

Enhanced Reliability Evaluation

As demonstrated in the stochastic Maximum Generation dispatch analysis above, all portfolios except the Retire Coal strategy can be energy self-sufficient on an annual basis. However, there will inevitably be times during which Duke Energy Indiana's generating fleet may not be sufficient to meet load in real time due to a combination of adverse conditions. As discussed in Appendix E, the composition of the MISO market and the capabilities of generating resources used to meet power system demand are projected to undergo significant change. This has led the electric power industry to conduct more thorough operational evaluation of a changing resource mix to meet future loads. For these same reasons, the Company has introduced an additional analysis to the 2024 IRP to further evaluate reliability considerations.

In this Enhanced Reliability Evaluation, the Company evaluates the dispatch of the Duke Energy Indiana system as an "island" (without the ability to interact with the market) through 11,000 simulations with varying weather conditions, load, and outages to further explore and measure the future performance of the portfolios in the Reference Scenario. This stochastic analysis explores the uncertain "tail" of risk inherent in power system operations that there may be times during which the Company is reliant *physically* on the broader market to supply the energy necessary to meet customer loads. The existence of periods of market reliance are expected as part of Duke Energy Indiana's participation in the MISO market (and indeed, the ability to draw on the market for both economic and reliability purposes is a benefit of this participation); however, analyzing the magnitude and characteristics of this market reliance can shed light on the capabilities of the evolving generation mix and its implied level of market integration. Market reliance is measured in this IRP using the industry standard metric of EUE. The Company compares portfolios in two ways, using the EUE metric.

First, the Company evaluated changes in the likelihood of market reliance (represented by simulated EUE) from 2028, when resource mixes are very similar across generation strategies, to 2035, by which time resource mixes materially diverge across generation strategies. Table 4-7 below shows EUE (averaged across simulations) for the Reference Case portfolios in 2035 as a ratio to a 2028 baseline (where portfolios all have very similar performance). A ratio of 1.0 indicates no projected change from 2028 to 2035, while a ratio greater than 1.0 indicates an increased likelihood of reliance on the MISO market to maintain energy sufficiency during some periods. (2.0 would indicate that EUE in 2035 is twice that of EUE in 2028.)

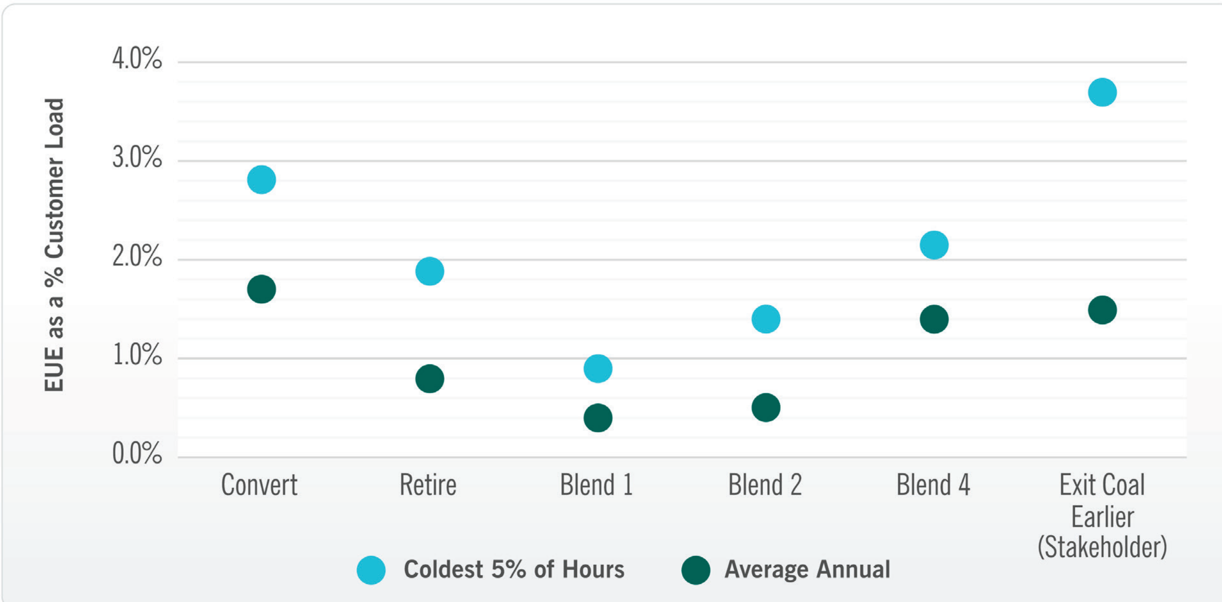
Table 4-7: Average 2035 EUE Relative to a 2028 Baseline

Portfolio	EUE in 2035 Relative to 2028
Convert/Co-fire Coal	3.6
Retire Coal	1.6
Blend 1	1.0
Blend 2	1.1
Blend 4	2.9
Exit Coal Earlier (Stakeholder)	3.1

Investigation of the 2035 results suggest that there are a handful of key drivers that lead to increasing market reliance/integration in most generation strategies. The first is that higher reliance on converted or co-fired coal units may be a potential risk factor as the expected reliability of these aging units is lower than that of a new, comparably sized advanced class combined cycle unit. This is evident in the substantive increase in EUE seen in the Convert and Blend 4 strategies, which continue to rely on much of the Company's existing steam unit capacity into the late 2030s and beyond. Additionally, generation strategies that rely most heavily on variable energy and energy-limited resources – particularly Convert and Exit Coal Earlier (Stakeholder) – experience a larger increase in potential market reliance. As the share of energy storage, which has no generating capability of its own, increases in the overall capacity mix, so too does the risk of reliance on the MISO energy market during forced outages on the thermal fleet or extended periods of low output from renewables.

To further explore differences in portfolio performance in 2035, the Company simulated EUE as a percentage of overall customer load during some of the most challenging time periods of cold winter weather and compared that cold weather performance to simulated EUE as a percentage of load over the entire year. Figure 4-28 below provides the results of that analysis.

Figure 4-28: 2035 Average Annual and 95th Percentile Cold Weather Simulated EUE as Percent of Customer Load



In 2035, all generation strategies experience higher probability of market reliance during these coldest hours, but the increase (as indicated by the spread between the green and blue circles) is most significant in the Exit Coal Earlier (Stakeholder) portfolio. As was discussed in the context of relative change from 2028, the level of reliance on storage and renewables may be a contributing factor to this outcome. In particular, Exit Coal Earlier (Stakeholder) has high reliance on solar and battery energy storage, creating potential energy limitations given the presence of both morning and evening load peaks.

Additional results and detailed modeling assumptions for the Enhanced Reliability Evaluation are presented in Appendix C.

Chapter 5: Preferred Resource Portfolio

Highlights

- Blend 2, the Preferred Portfolio, lays out a balanced strategy to mitigate ongoing cost and reliability risks by retiring and replacing aging coal units while upgrading others to co-fire coal and natural gas in compliance with the Environmental Protection Agency's Clean Air Act Section 111 Rule, providing long-term benefits for customers and limiting near-term cost impacts.

- By adding over 1,500 megawatts of incremental firm summer capacity above and beyond the retiring coal capacity by 2032, Blend 2 provides robust support for Indiana's growing economy and ensures a reliable energy transition.

- Blend 2 provides the flexibility needed to navigate dynamic market conditions and evolving environmental regulations, which is critical amid times of change and uncertainty.

Duke Energy Indiana (or the "Company") developed its 2024 Integrated Resource Plan ("IRP") through a comprehensive, stakeholder-informed process to identify the resource portfolio that appropriately balances the six resource planning objectives of reliability, affordability, environmental sustainability, resiliency, system stability, and risk mitigation. The robust analytical framework, described in Chapter 2 (Methodology), was centered around six generation strategies, each of which was evaluated in three potential scenarios for the future, or "worldviews." To further examine the detailed implications of specific resource decisions, and to test the sensitivity of model results to variability in individual inputs, the Company constructed additional strategy variations and conducted sensitivity analysis around both resource selection and portfolio operations. The results of this thorough IRP analysis, which yielded 45 potential resource portfolios and additional supporting information, are presented in Chapter 4 (Candidate Resource Portfolios). Considering those results, Duke Energy Indiana has identified Blend 2 as the Preferred Portfolio that will safely, reliably, efficiently, and cost-effectively meet future electric system demand, taking cost, risk, and uncertainty into consideration.

Preferred Portfolio for the 2024 Integrated Resource Plan: Blend 2

The resource portfolio for the Blend 2 Generation Strategy developed in the Reference Scenario (the "Preferred Portfolio") achieves the appropriate balance across resource planning objectives, providing an executable path to adding needed incremental generating capacity to maintain reliability while serving growing load, improving environmental sustainability with a mix of low-emitting natural gas and carbon-free renewable energy sources, mitigating reliability and cost risk through the retirement of aging coal assets, and doing so in a cost-effective manner for Duke Energy Indiana's customers.

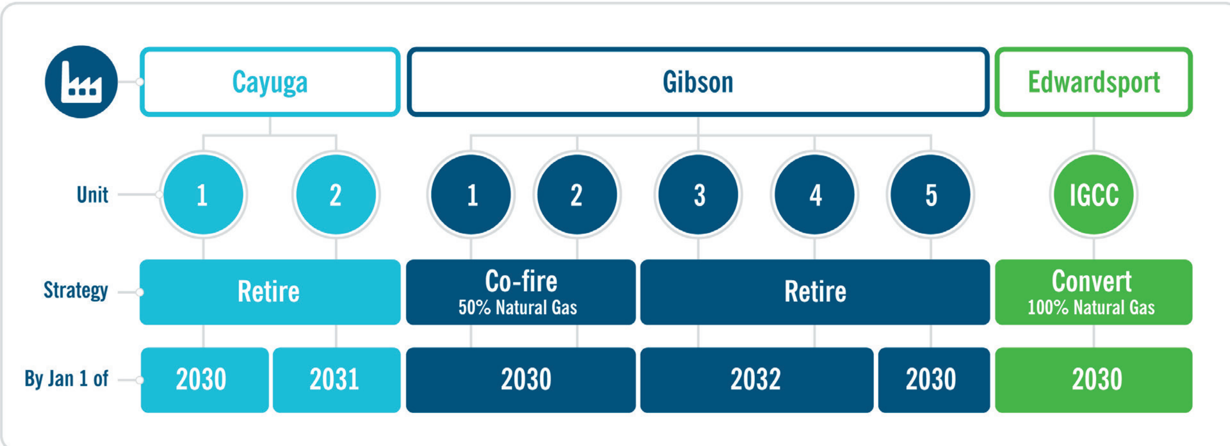
As described in Chapter 2, Duke Energy Indiana developed the Generation Strategies for the 2024 IRP around different approaches to compliance with the Environmental Protection Agency ("EPA") Clean Air Act Section 111 May 2024 Final Rule ("EPA CAA Section 111 Rule"). The Blend 2 Generation Strategy includes the following actions at the Company's existing coal-fired generating stations, which are summarized in Figure 5-1 below:

- **Cayuga Station:** Retire the two existing coal-fired generators, Cayuga units 1 and 2, by the beginning of 2030 and the beginning of 2031, respectively, and replace each with a 1x1 combined cycle ("CC") generator at time of retirement. This will provide an estimated 440 megawatts ("MW") of increased generating capacity at the site. Installing two 1x1 CCs at the site rather than a single 2x1 machine mitigates reliability and resiliency risks through diversification without materially increasing portfolio cost, as reported in the discussion of strategy variations below, and will allow the Company to better manage operations and outage planning. Continued operation of the Cayuga steam generators into the late 2030s would be complicated by the need to comply with EPA's Effluent Limitation Guidelines and potentially add costly equipment like closed-cycle cooling to achieve compliance with sections 316(a) and 316(b) of the Clean Water Act, which govern discharge temperatures and intake structures.

- **Gibson Station:** Upgrade units 1 and 2 to enable natural gas co-firing up to 50% of full load, providing the potential for these units to continue operating through the end of 2038 in compliance with the EPA CAA Section 111 Rule. Retire units 3 and 4 by the beginning of 2032 and replace them with a 2x1 combined cycle generator, resulting in an estimated net increase of 177 MW of generating capacity. Retire Unit 5 by 2030, the energy and capacity of which will be more than offset by new solar (for energy) and battery energy storage (for capacity) to be placed in service across the Duke Energy Indiana system by the end of the 2020s.

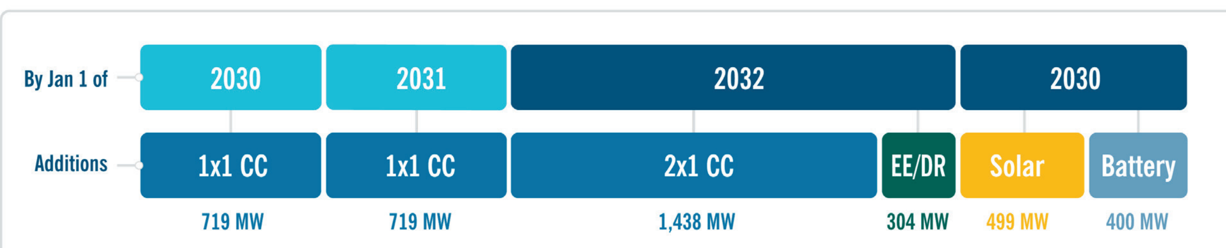
- **Edwardsport Integrated Gasification Combined Cycle ("IGCC"):** Prepare to retire the gasifiers and optimize the facility to run on 100% natural gas fuel by 2030 in compliance with the EPA CAA Section 111 Rule. In the near-term, Duke Energy Indiana will simultaneously complete the ongoing front-end engineering and design ("FEED") study for potential carbon capture and sequestration ("CCS") at the facility, which could enable continued gasification of coal into the 2040s while reducing CO_2 emissions by over 90%.

Figure 5-1: Summary of Blend 2 Strategy for Existing Resources



The Company prescribed coal unit retirements and conversions in the 2024 IRP capacity expansion modeling as part of its effort to evaluate a broad array of compliance pathways. The economic selection of the replacement resources is supported by the range of model results described in Chapter 4 and in the Blend 2 Strategy Variations section of this Chapter. In addition to the resource additions specified above, the Preferred Portfolio also includes 499 MW of new solar and 400 MW of battery energy storage by 2030, as well as over 300 MW of incremental contributions from energy efficiency ("EE") and demand response ("DR") programs by 2032, as shown in Figure 5-2 below.

Figure 5-2: Blend 2 Model-Selected Resource Additions by 2032



Annual detail on energy mix, installed capacity mix, and resource additions and retirements in the Preferred Portfolio is provided in Figure 5-3, Figure 5-4, and Table 5-1 below.

Figure 5-3: Preferred Portfolio (Blend 2) Modeled Energy Mix Over Time

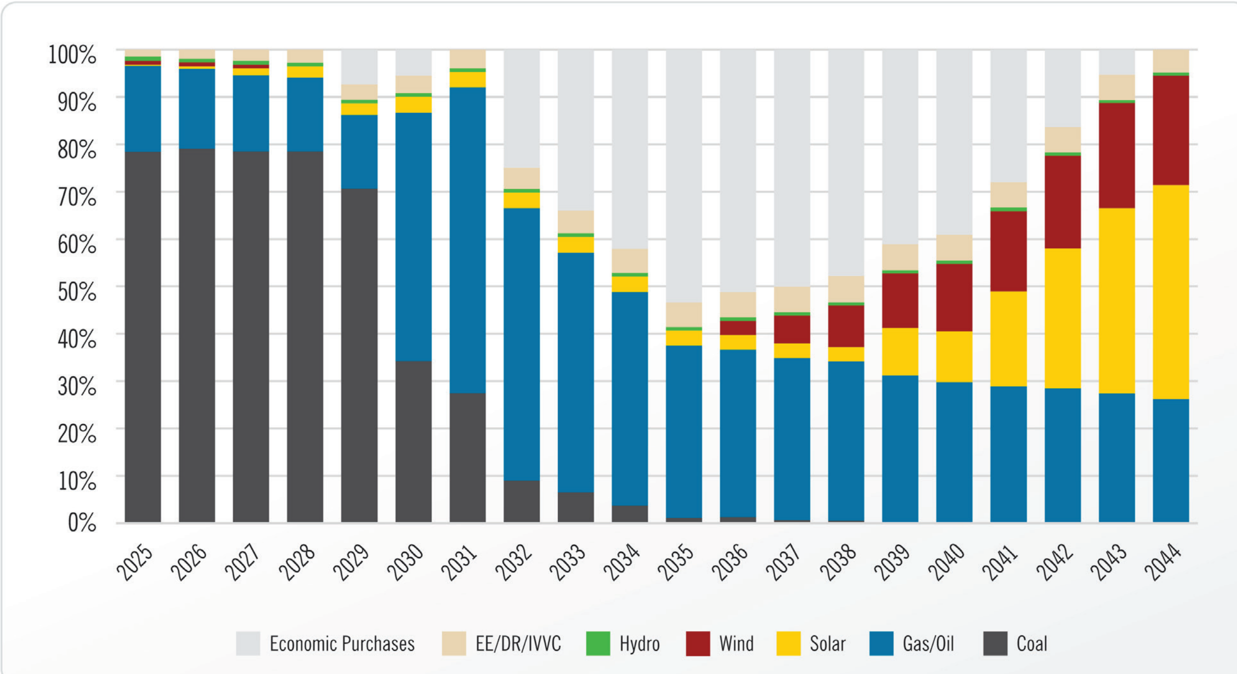
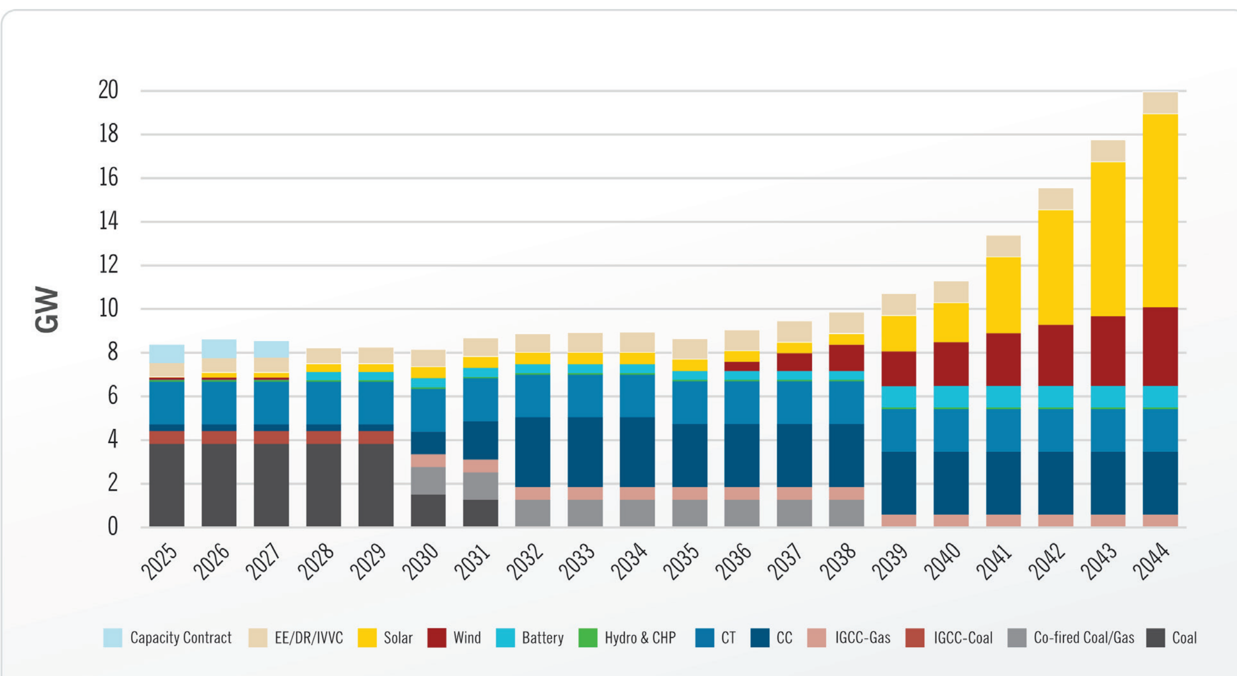


Figure 5-4: Preferred Portfolio (Blend 2) Installed Capacity Mix Over Time (beginning-of-year basis)



Note: Integrated Volt-Var Control ("IVVC")

Table 5-1: Preferred Portfolio (Blend 2) Annual Resource Changes (Installed MW, beginning-of-year basis)

Existing Resource Changes & Retirements (MW)																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Cayuga 1	-	-	-	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cayuga 2	-	-	-	-	-	(256)	(240)	-	-	-	-	-	-	-	-	-	-	-	-	-
Gibson 1	-	-	-	-	-	Cofire	-	-	-	-	-	-	-	-	(632)	-	-	-	-	-
Gibson 2	-	-	-	-	-	Cofire	-	-	-	-	-	-	-	-	(633)	-	-	-	-	-
Gibson 3	-	-	-	-	-	-	-	(635)	-	-	-	-	-	-	-	-	-	-	-	-
Gibson 4	-	-	-	-	-	-	-	(626)	-	-	-	-	-	-	-	-	-	-	-	-
Gibson 5	-	-	-	-	-	(313)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Edwardsport	-	-	-	-	-	Conv	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Noblesville CC	-	-	-	-	-	-	-	-	-	-	(312)	-	-	-	-	-	-	-	-	-
Wind PPA	-	-	-	(100)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PPA	-	-	-	-	-	(4)	-	-	-	-	-	(11)	(11)	-	-	-	-	-	-	-
Resource Additions (MW)																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
1x1 CC	-	-	-	-	-	719	719	-	-	-	-	-	-	-	-	-	-	-	-	-
2x1 CC	-	-	-	-	-	-	-	1,438	-	-	-	-	-	-	-	-	-	-	-	-
Solar[1]	-	199	-	150	-	150	-	-	-	-	-	-	-	-	1,150	150	1,700	1,750	1,800	1,800
Wind	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	400
Battery[1]	-	-	-	350	-	50	-	-	-	-	-	-	-	-	550	25	-	-	-	-
EE/DR/IVVC[2]	76	22	39	32	35	38	32	20	29	28	16	13	15	13	9	3	4	13	4	1

Note 1: Includes paired.

Note 2: EE/DR/IVVC additions, net of annual program roll-off.

Winter and summer load, capacity, and reserves tables for Blend 2 as well as annual revenue requirements are provided in Appendix C (Quantitative Analysis).

Blend 2 Strategy Variations

As explained in Chapter 2, Duke Energy Indiana evaluated several variations on the Blend 2 strategy to confirm certain resource decisions and provide additional information to guide the development of the Short-Term Action Plan. The impact of these variations on total portfolio cost as measured by the present value of revenue requirements ("PVRR") is presented in Table 5-2 below.

Table 5-2: Cost Impact of Blend 2 Strategy Variations

Blend 2 Baseline	PVRR ($ billions)	
Reference Case	$24.3	
Blend 2 Variation	**PVRR Change ($ billions)**	**PVRR Change (%)**
Edwardsport CCS	($0.9)	-3.8%
Edwardsport Natural Gas Conversion by 2028	($0.1)	-0.6%
Cayuga 2x1 CC	($0.1)	-0.3%
Gibson 1&2 Natural Gas Conversion	($0.0)	-0.1%
Add 600 MW SMR by 2038	$0.7	2.9%
Blend 2 in a "No 111" Future (production cost only)	($0.7)	-2.8%

These results indicate that the tax credits that could be gained by adding CCS capability to the Edwardsport IGCC could offer cost savings relative to pursuing natural gas conversion as the preferred option for compliance with the EPA CAA Section 111 Rule. However, while these potential savings make it reasonable for the Company to complete the ongoing FEED study for the facility, they represent a best-case outcome for the CCS option. The risks associated with successful CCS project completion by the 2032 deadline under the EPA CAA Section 111 Rule, continued reliable operation of both the CCS system and the Edwardsport gasifiers for the 12 years over which the tax credits could be earned, and the successful monetization of the full credit value for customers make natural gas conversion the prudent option for Edwardsport in the Preferred Portfolio at this time.

Similarly, analysis of converting Edwardsport to natural gas by 2028 also shows potential savings, albeit at a much lower level, offering a PVRR reduction of approximately 0.6%. However, Duke Energy Indiana remains confident in the value of the flexibility and optionality provided by the IGCC and will continue to evaluate CCS while remaining prepared to retire the gasifiers by 2030 should that prove to be the most reasonable and prudent compliance option under the EPA CAA Section 111 Rule.

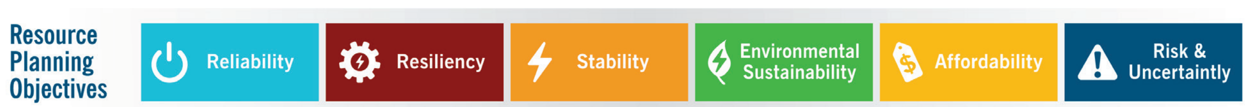
Installing a single 2x1 CC at Cayuga rather than two 1x1 CC units also has the potential to offer a small amount of savings due to the economies of scale associated with the larger machine. The capacity is the same for both options, however, and mitigation of reliability and resiliency risks through diversification, combined with the ability to better manage operations and outage planning, makes two 1x1 machines the reasonable and prudent choice for Cayuga.

In addition to co-firing Gibson units 1 and 2, the Company also evaluated conversion to 100% natural gas fuel as a potential means of complying with the EPA CAA Section 111 Rule. However, the very small savings that could be gained by full natural gas conversion, which are associated with the requirement that co-fired units be retired and replaced by the end of 2038, do not offset the value of risk mitigation that preserving fuel diversity at Gibson provides.

Small modular reactors ("SMR") were not economically selected in Blend 2 capacity expansion modeling. However, given the potential value of future around-the-clock, carbon-free generation, the Company evaluated a variation in which it added 600 MW of SMR (two units) to the portfolio by 2038. The resulting cost increase confirmed the decision to exclude the resource from the 2024 Preferred Portfolio, but the Company will continue to evaluate SMRs as supply-side resource options in future IRPs.

Finally, the Company evaluated the operating costs and characteristics of a Blend 2 portfolio in a future without the constraints of the EPA CAA Section 111 Rule. No changes were made to the resources in the portfolio for this analysis. In this case, in a future in which the requirements of the EPA CAA Section 111 Rule are lifted after the Company has proceeded down the Blend 2 path, the resulting cost savings would exceed 2.8% of the base Blend 2 PVRR.

Blend 2 Appropriately Balances Resource Planning Objectives



Under Indiana regulation, the Preferred Portfolio must "safely, reliably, efficiently, and cost-effectively [meet] the electric system demand, taking cost, risk, and uncertainty into consideration."[1] This section discusses how Blend 2 accomplishes those ends, appropriately balancing the planning objectives described in Chapter 2. The focus here is on the advantages of Blend 2 relative to the other generation strategies evaluated in the 2024 IRP with respect to specific planning considerations and the balance across objectives. A complete discussion of results for all candidate portfolios is presented in Chapter 4 and additional detail is provided in Appendix C.

Blend 2 is an Executable Strategy to Add Incremental Capacity at Moderate Cost

With the Blend 2 generation strategy, Duke Energy Indiana plans to add over 2,800 MW of highly efficient advanced class combined cycle generation, 500 MW of solar, and 400 MW of battery energy storage to the system by the beginning of 2032. In addition, the Company expects to achieve over 300 MW of incremental savings through growing contributions from energy efficiency and demand response programs by 2032. This diverse mix of new resources represents a net increase of over 1,500 MW of firm summer capacity above and beyond replacement capacity for the aging Cayuga and Gibson 3-5 coal units that the Company plans to retire by 2032, improving reliability and providing

[1] 170 Indiana Administrative Code 4-7-1.

robust support for continued economic development. The retirement and replacement of these existing units is balanced with the modification of Gibson units 1 and 2 for co-firing coal and natural gas, and conversion of Edwardsport IGCC to 100% natural gas, which will enable their continued operation in compliance with the EPA CAA Section 111 Rule. This reasonable, moderate pace of energy transition prudently mitigates costs and execution risks relative to other potential strategies, while improving environmental sustainability and system reliability.

Figure 5-5 below is the 2024 IRP scorecard, which summarizes the results of the six generation strategies across the 15 metrics used to measure performance with respect to the planning objectives. A description of each scorecard metric is provided in Chapter 2 and additional detail on metric calculation methods can be found in Appendix C. The performance of Blend 2 in comparison to other strategies is discussed in the sections that follow.

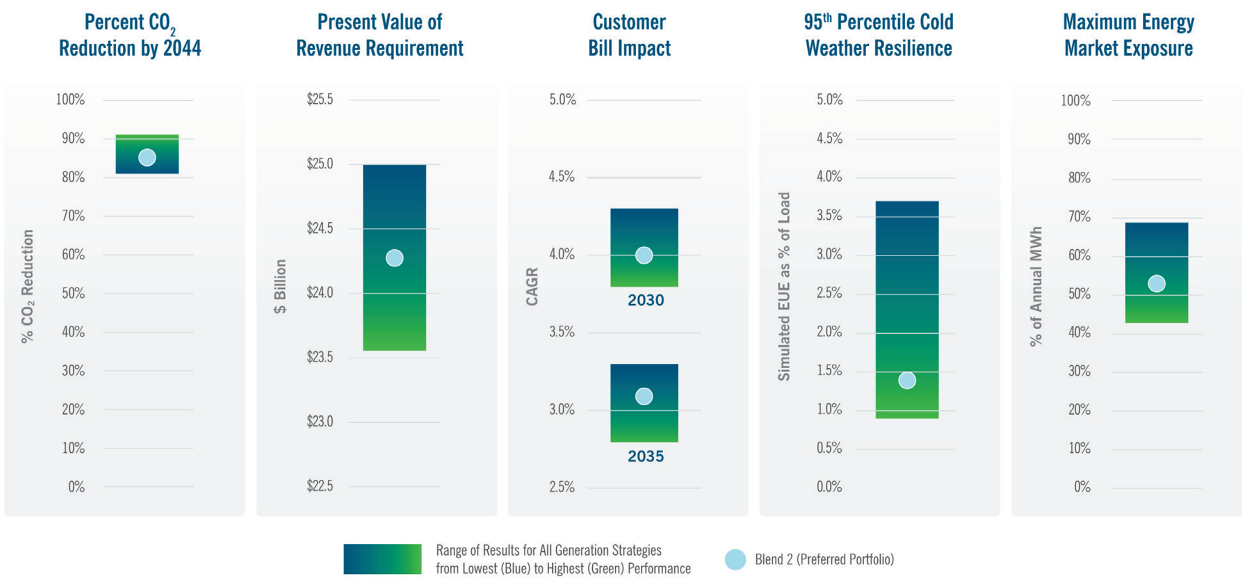
Figure 5-5: 2024 IRP Scorecard

Portfolio Scorecard			Convert/Co-Fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier (Stakeholder)
Environmental Sustainability	CO_2 Emissions Reduction	2035	74%	73%	70%	72%	74%	72%
		2044	91%	81%	81%	84%	88%	86%
	Cumulative CO_2 Reduction (Mt)	2044	367	340	337	348	367	362
	CO_2 Intensity of Duke Energy Indiana Portfolio (lbs./MWh)	2035	715	572	710	678	666	652
Affordability	PVRR ($B)	2044	$25.0	$23.6	$24.2	$24.3	$24.5	$24.3
	Customer Bill Impact (CAGR)	2030	3.9%	3.7%	3.9%	4.0%	4.0%	4.3%
		2035	3.1%	3.3%	2.8%	3.1%	2.9%	3.1%
Reliability	Fast Start Capability	2035	39%	31%	33%	33%	33%	38%
	Spinning Reserve Capability	2035	93%	93%	98%	102%	100%	87%
Resiliency	Resource Diversity (HHI)	2035	1766	3853	2802	2739	1758	2291
	Simulated EUE in 95th Percentile Cold Weather (Islanded System)	2035	2.8%	1.9%	0.9%	1.4%	2.1%	3.7%
Cost Risk	Cost Variability Across Scenarios ($B)	2044	$24.0-$28.1	$21.8-$26.8	$22.4-$27.2	$22.9-$26.9	$23.3-$27.8	$23.4-$27.2
	IRA Exposure	2030	81%	43%	81%	50%	49%	57%
		2035	81%	29%	20%	22%	33%	39%
Market Exposure	Fuel Market Exposure	Average	61%	72%	76%	72%	66%	70%
	Maximum Energy Market Exposure	Annual Max.	69%	43%	51%	53%	66%	52%
Execution Risk	Cumulative Resource Additions in MW	2030	1,037	1,656	1,037	1,856	1,831	2,181
		2035	1,823	5,568	4,049	4,149	2,686	4,105
	Cumulative Resource Additions as % of Current System	2030	13%	20%	13%	23%	23%	27%
		2035	22%	69%	50%	51%	33%	51%

Note: Expected Unserved Energy ("EUE") is stochastically simulated for Duke Energy Indiana as an islanded system.

Balancing multiple objectives that are often in tension is a challenge. As shown in the scorecard results in Figure 5-5 above, no generation strategy is consistently the best performer with respect to all of the planning objectives. Most strategies outperform the group on certain metrics while underperforming on others. The Preferred Portfolio achieves balance across planning objectives and scorecard metrics, delivering better-than-average results for most metrics and never delivering the worst performance on any one metric. Figure 5-6 below provides a visual illustration of the Preferred Portfolio's balanced performance across selected key metrics.

Figure 5-6: Preferred Portfolio Results for Selected Scorecard Metrics Within the Range of Results for All Generation Strategies



Blend 2 Balances Total Cost & Near-Term Customer Bill Impacts

PVRR is a measure of the total cost of a resource portfolio over the 20-year planning period. In the 2024 IRP, PVRR results for Blend 1, Blend 2, Blend 4, and Exit Coal Earlier (Stakeholder) fall within a range of approximately $300 million (approximately 1.4% of the average PVRR across all strategies). The Convert/Co-fire Coal strategy is the most expensive of the strategies evaluated, with a total PVRR about $500 million greater than the next most expensive, driven by continued reliance on inefficient aging steam units through the 2030s and into the 2040s. At the other end of the range, the Retire Coal strategy has the lowest PVRR by approximately $600 million. However, while Retire Coal offers the lowest total cost over the planning period as indicated by PVRR, the projected customer bill compound annual growth rate ("CAGR") for that strategy by 2035 is the highest due to the 5,542 MW of new capacity (1,437 MW more than Blend 2) required by 2035 to replace retiring coal. The similarly aggressive Exit Coal Earlier (Stakeholder) strategy, which retires Gibson units 3-5 by 2030, also drives increases in projected customer bills, with the highest bill CAGR through 2030 of all strategies considered. The measured approach of Blend 2, which lowers long-term costs by replacing some aging assets and mitigates near- and intermediate-term bill impacts by modifying other existing facilities to allow continued operation, strikes the appropriate balance.

Blend 2 Improves Environmental Sustainability

The pace and amount of CO_2 emissions reduction, which are the representative indicators for environmental sustainability, do not vary substantially across generation strategies. As illustrated in Chapter 4, all strategies achieve substantial reductions from 2030 to 2035 as coal-fired units are retired or modified to burn natural gas, and all strategies maintain steady reductions through the remainder of the planning period as growing contributions from renewable sources displace energy market purchases. Blend 2 follows this trend, achieving reductions better than the average.

Blend 2 Balances Risks Related to Cost, Reliability, Resiliency & Execution

The same measured Blend 2 approach that balances costs also balances risk in an increasingly uncertain energy landscape. Some risks, like operating and compliance cost risks, and reliability and resiliency risks, can be mitigated by retiring aging assets and transitioning to a more modern, diverse, and environmentally sustainable resource portfolio. However, that transition comes with its own costs (as described in the customer bill impact discussion above) and execution risks.

The Retire Coal and Exit Coal Earlier (Stakeholder) strategies both call for a rapid pace of transition, improving CO_2 intensity of the portfolio more quickly and limiting exposure to the Midcontinent Independent System Operator ("MISO") energy market relative to other strategies. To achieve this, the Exit Coal Earlier (Stakeholder) strategy requires retiring nearly 1,600 MW of coal, adding over 2,100 MW of new resources, and converting Cayuga and Edwardsport stations to run on natural gas all by the end of this decade. The cost of this aggressive pace is reflected in the 2030 bill impact, and the execution risk exceeds that of other strategies over this period. Similarly, the Retire Coal strategy requires over 5,500 MW of new resources to be added by 2032, creating cost pressures and increasing plan execution risk.

The Convert/Co-fire Coal strategy, on the other hand, does not retire any of the existing steam generators (currently fueled with coal) until the late 2030s. Instead, these units are co-fired or entirely converted to natural gas fuel in compliance with the EPA CAA Section 111 Rule. This approach of postponing any transition fails to deliver cost savings (Convert/Co-fire Coal has similar bill impacts to Blend 2 and the highest total PVRR of any strategy), adds the least incremental generating capacity, and carries the highest exposure to MISO energy market price volatility. In addition, failing to replace aging steam generators results in the highest resiliency risk during extreme weather events, as indicated on the scorecard by simulated EUE for the Duke Energy Indiana system in isolation.

Blend 2 balances these extremes with a reasonable and prudent pace of transition that delivers incremental capacity, reduces risks associated with aging coal units, mitigates cost impacts, and improves environmental sustainability. Blend 1 and Blend 4 also take a moderate approach, but each has drawbacks that make Blend 2 the Preferred Portfolio. Blend 1 takes a similar approach to Blend 2, but it calls for converting the Cayuga units to run on natural gas rather than retiring them. Continuing to operate these units, which are the oldest remaining steam generators in the Company's portfolio, carries more long-term risk than Blend 2, which instead keeps Gibson units 1 and 2 online beyond 2032. In addition, the Cayuga units face significant environmental compliance costs, which contribute to making them the preferred units for retirement and replacement.

Like Blend 2, Blend 4 retires the Cayuga coal units and co-fires Gibson units 1 and 2. However, Blend 4 does not retire Gibson units 3 and 4 by 2032, but instead converts them to run on natural gas in compliance with the EPA CAA Section 111 Rule. This approach results in a somewhat lower customer bill CAGR through 2035 (although not through 2030) but has a higher total PVRR over the planning period. Blend 4 also delivers less incremental capacity by 2035 than does Blend 2. The combination of lower PVRR and greater incremental capacity makes Blend 2 the Preferred Portfolio over Blend 4, but the Company will continue to monitor market conditions over the coming months and evaluate the most prudent course of action for Gibson units 3 and 4. The following section discusses in greater detail the flexibility to adapt to changing conditions that Blend 2 provides.

Blend 2 Meets Near-Term Needs While Preserving Optionality to Adapt to Changing Conditions

Duke Energy Indiana has proudly provided safe and reliable service to residential customers, communities, and commercial, governmental, and industrial enterprises across Indiana for over a century. To build on its track record and support Indiana's growing economy over the coming years, the Company will need to add additional sources of energy and capacity while reducing the costs and risks associated with reliance on aging assets. Blend 2 accomplishes this with near-term additions of solar power generation and battery energy storage, as well as the addition of new highly efficient, dispatchable combined cycle generators at Cayuga and Gibson stations to replace retiring coal assets and provide incremental capacity. In addition, Blend 2 provides a pathway to compliance with the EPA CAA Section 111 Rule through co-firing two Gibson units on coal and natural gas fuels, and fully optimizing Edwardsport to run only on natural gas fuel.

Blend 2 provides a reasonable and prudent path forward based on current expectations for the future, but, as explained in Chapter 1 (Planning for the Future Energy Landscape), there is considerable uncertainty around these expectations, particularly pertaining to the contested EPA CAA Section 111 Rule, ongoing supply chain and interconnection challenges that influence the pace and cost at which new resources can be deployed, and the timing and magnitude of large economic development projects, which can have significant impacts on the load forecast. In this uncertain planning environment, it is essential that the Preferred Portfolio include opportunities to check and adjust the plan as conditions evolve, even in the near term. As described in more detail in Chapter 6 (Short-Term Action Plan), Blend 2 mitigates risk and uncertainty with a combination of short-term actions that are reasonable and prudent across a wide range of future conditions, while maintaining the flexibility to adjust other actions in response to changing conditions.

High Confidence Actions Prudent Across a Wide Range of Future Conditions

The addition of highly efficient, advanced class combined cycle generators to replace the aging Cayuga coal units and add much-needed incremental generating capacity is beneficial across a variety of market conditions and regulatory regimes. As reported in Chapter 4, this additional combined cycle capacity is selected in both the Aggressive Policy & Rapid Innovation and the Minimum Policy & Lagging Innovation scenarios, as well as in the high CC cost sensitivity analysis and the low load sensitivity analysis, reflecting the value of these resources even at a higher cost than the base assumption, and even if customer demand does not reach the levels projected in the base forecast.

Similarly, near-term additions of solar and battery energy storage resources are supported by all portfolios and sensitivity analyses evaluated for this IRP. The relatively short project lead times for these resources make them effective tools for meeting increasing customer demand in the short term, while improving environmental sustainability and portfolio diversity over the long term.

In addition to supply-side resources, the Company has high confidence in the value of energy efficiency and demand response programs and the prudence of continuing to build on past success in these areas. Duke Energy Indiana will continue to execute on its existing EE and DR programs and will explore additional opportunities to grow demand-side contributions.

Finally, while nuclear resources were not economically selected in this IRP, advanced nuclear technologies such as SMRs offer the potential to add considerable value for customers. The combination of significant cost uncertainty for SMRs and the possibility of delivering reliable, around-the-clock, carbon-free generation in the future makes it prudent for Duke Energy Indiana to continue to advance early studies and maintain advanced nuclear as a viable option in subsequent resource plans.

Dynamic Market Conditions & Evolving Pace & Scale of Customer Load Growth

The Preferred Portfolio calls for the replacement of Gibson units 3 and 4 with a new 2x1 combined cycle generator, a move that would decrease cost and reliability risk and yield a net increase in generating capacity. However, analytical results across all generation strategies and sensitivity analyses (presented in Chapter 4) indicate that higher CC costs and high load could both alter the most reasonable path for Gibson 3 and 4, albeit in different ways.

In the Reference Scenario results, Blend 2 is a lower-cost strategy than Blend 4, a strategy that is similar to Blend 2 but contemplates natural gas conversion of Gibson units 3 and 4 rather than retirement. However, in the sensitivity analysis testing the impacts of higher CC costs (1.6 times the base forecasted resource cost), Blend 4 becomes the lower-cost strategy as measured by the PVRR. This suggests that if the cost of CC generators continues to climb over the coming months, it may be reasonable to adjust course to natural gas conversion of Gibson 3 and 4.

The impact of high load is somewhat different. In the Reference Case, the capacity expansion model selects a total of 2,876 MW of new CC capacity by 2032, equivalent to two 1x1 CCs at Cayuga and a 2x1 CC at Gibson. However, in the High Load sensitivity analysis, the model selects an additional

1,438 of CC capacity by 2032, equivalent to a second 2x1 CC. This additional CC could present execution challenges, and further assessment could indicate that natural gas conversion to maintain the existing capacity of Gibson units 3 and 4, deferring the need for the second 2x1 CC, could be a more reasonable option in a High Load future.

Of course, neither cost nor load is likely to vary in isolation while all other conditions remain constant, but the many alternatives evaluated by the Company in the 2024 IRP analysis provide a level of confidence that Blend 2 preserves the flexibility needed to adapt to changing market conditions.

Uncertain Future for Compliance Deadlines Under the EPA CAA Section 111 Rule

Blend 2 also provides options to adapt to a changing regulatory environment, specifically with regard to potential changes to compliance deadlines under the contested EPA CAA Section 111 Rule. While pursuing new CC generation to replace the retiring Cayuga units and Gibson units 3 and 4 is consistent with both EPA CAA Section 111 Rule-compliant strategies and the “No 111” portfolio described in Chapter 4, certain other actions could be adjusted in response to any change to compliance requirements or deadlines under the rule.

Specifically, the modification of Gibson units 1 and 2 to enable co-firing on natural gas that is contemplated as a compliance option for Blend 2 could be deferred in accordance with any potential future changes to the EPA CAA Section 111 Rule. Similarly, if changing market conditions or load projections lead the Company to reconsider the retirement of Gibson units 3 and 4, it could opt to delay action on those units while awaiting regulatory certainty. The same is true at Edwardsport, where a delay in EPA CAA Section 111 Rule compliance deadlines could allow continued coal gasification while the Company evaluates alternative options.

The near-term activities discussed in this section are presented in more detail in Chapter 6.

6

Chapter 6: Short-Term Action Plan

Highlights

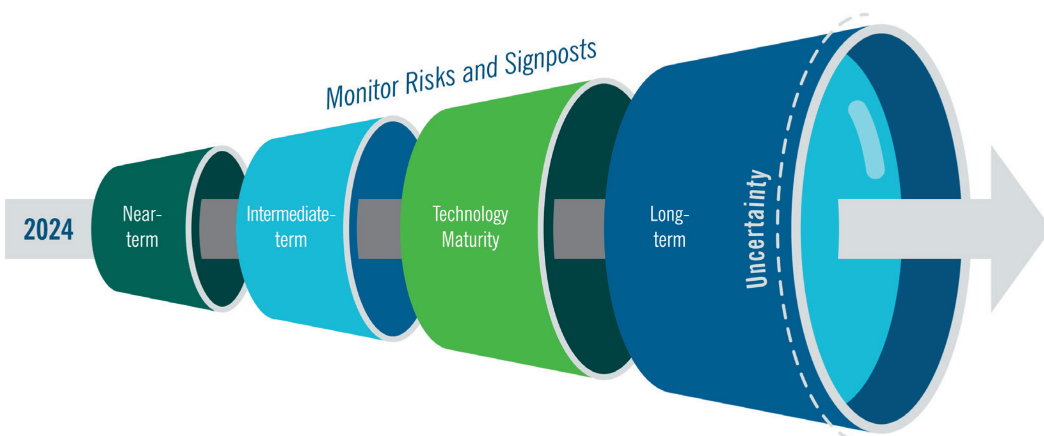
- The Short-Term Action Plan presents the reasonable and prudent steps that Duke Energy Indiana will take over the next three years (2025-2027) to implement the Preferred Portfolio.
- These steps support the addition of solar and energy storage resources by 2030, new combined cycle capacity at Cayuga and Gibson stations by the early 2030s, and continued implementation of cost-effective demand response and energy efficiency programs to help manage growing load.
- The Short-Term Action Plan incorporates flexibility to adjust to changing conditions, an essential aspect of planning, particularly in light of the considerable uncertainty that comes with the changing energy landscape.

The Preferred Portfolio for the 2024 Duke Energy Indiana (the "Company") Integrated Resource Plan ("IRP") features a measured approach to the energy transition, adding needed incremental capacity to support Indiana's growing economy while reducing reliance on aging coal units and executing a balanced transition to a more efficient, reliable, and environmentally sustainable resource mix. The Preferred Portfolio is presented and discussed in Chapter 5 (Preferred Resource Portfolio). This Chapter presents a Short-Term Action Plan that details the reasonable and prudent steps needed to support the Preferred Portfolio, including opportunities to check and adjust the plan as events unfold while monitoring signposts that inform future decisions. The Short-Term Action Plan includes activities related to: (1) existing supply-side resources, (2) new supply-side resources, (3) transmission system planning, and (4) demand-side resources. Finally, in addition to the identified activities outlined in this Chapter, the Company continually evaluates emerging opportunities to pursue prudent incremental supply-side and demand-side resources that can meet growing customer needs while balancing the planning objectives outlined in Chapter 2 (Methodology).

Navigating Uncertainty

The Preferred Portfolio requires the Company to implement near-term actions while monitoring risks and signposts across the planning horizon. While long-term planning and modeling processes can assess many of these risks and signposts to make informed planning decisions, such modeling presents a “snapshot in time” of resource planning and relies on numerous assumptions that become increasingly difficult to predict out into future years as the band of uncertainty widens regarding technology, cost, policy, consumer trends and economic conditions. Concurrently, impacts to Indiana’s Five Pillars (Reliability, Resiliency, Stability, Affordability, and Environmental Sustainability) are monitored as they constitute key objectives of the plan. Proactive risk and signpost monitoring will provide information that will be used to navigate uncertainty by checking and adjusting future IRPs, as illustrated in Figure 6-1 below and described in more detail later in this Chapter.

Figure 6-1: Navigating Uncertainty Across Planning Horizons



While the risks and uncertainties described above and in Chapter 1 (Planning for the Future Energy Landscape) are challenges in any resource planning cycle, the Company is faced with unusually significant uncertainty in the 2024 IRP with respect to three factors: (1) the future pace of economic development and associated growth in customer load, (2) the eventual outcome of litigation related to the Environmental Protection Agency’s (“EPA”) May 2024 finalized rule governing greenhouse gas emissions under Sections 111(b) and 111(d) of the Clean Air Act (“CAA”) and other environmental rules, and (3) the pace and cost at which new resources can be deployed as existing supply chain and interconnection challenges are exacerbated by the twin pressures of growing demand and tightening regulatory restrictions. Monitoring developments in these areas over the next three years will be critical for balanced and prudent decision making. This Short-Term Action Plan identifies the signposts that will provide Duke Energy Indiana with the necessary information to check and adjust the plan as appropriate.

Optimizing for Execution

The IRP process results in a long-term plan, which is based on reasonable, generic planning unit quantities and approximate in-service dates for modeling purposes. As more detailed development and siting for specific resources begin, there will be refinements and modifications, as needed, to quantities and timing as the Company optimizes for execution and considers a multitude of practical factors that are beyond the scope of the long-term planning process. Adjustments to quantity and timing could be based on generation market solicitations, pricing and economics, sourcing, technology specifications, supply chain availability (e.g., materials, labor), permitting timelines, and other evolving factors. It should reasonably be expected that the precise size of generating units acquired or constructed and the timing of resource execution activities may vary from the Preferred Portfolio's generic planning units and approximate dates as the Company seeks to meet the resource needs identified in the 2024 IRP.

Activities Since Submitting the 2021 Integrated Resource Plan

Over the past three years, Duke Energy Indiana has made steady progress in advancing the energy transition. Consistent with the short-term action plan for the 2021 IRP, the Company issued an all-source request for proposal ("RFP") for new generation resources in 2022. Through that process, the Company secured a long-term power purchase agreement for the capacity and energy from the 199-megawatt ("MW") Speedway Solar plant that is scheduled to go in-service in 2025. The Company issued a second all-source RFP in late 2023 and is currently evaluating bids received via that solicitation. In addition, the Company built and brought online new combined heat and power ("CHP") generation at Purdue University to supply steam and backup power in case of an outage, and started the permitting process for new, highly efficient natural gas-fired generation to replace the aging Cayuga coal units.

In 2023, the Company was awarded funding by the Department of Energy ("DOE") to complete a carbon capture and sequestration ("CCS") front-end engineering design ("FEED") study at its integrated gasification combined cycle ("IGCC") facility in Edwardsport, Indiana. The post-combustion capture system will be designed to enable maximum fuel flexibility, from coal-gasified syngas, natural gas and syngas/natural gas blends. In July 2024, the DOE approved the study to enter budget period two, which includes the detailed engineering and full project cost estimate. The study is expected to be completed in 2026 and will inform a final decision on the most reasonable and prudent path forward for the Edwardsport facility.

In addition, the Company partnered with Purdue University in April 2022 to conduct a nuclear feasibility study on small modular reactors ("SMR") and advanced reactors ("AR"). An interim report was published in May 2023.[1] The advanced nuclear and CCS efforts showcase Duke Energy Indiana's continued commitment to developing cleaner dispatchable generation technologies and will help the

[1] Purdue University and Duke Energy, Small Modular Reactor and Advanced Reactor Feasibility Study Interim Report, May 2023, available at https://www.purdue.edu/administrative-operations/nuclear/documents/smr-feasibility-study-interim-report.pdf.

Company to further refine its planning assumptions related to the costs and operating characteristics of these technologies.

For transmission, the Company continues to work closely with the regional transmission organization ("RTO"), Midcontinent Independent System Operator ("MISO"), participating on planning and stakeholder committees. These committees include work on MISO's queue reform, MISO Transmission Expansion Plan ("MTEP"), and the Long Range Transmission Plan ("LRTP"). The focus of LRTP is to improve the ability to move electricity across the MISO region from where it is generated to where it is needed – reliably and at the lowest possible cost. See Appendix I (Transmission Planning) for more information. Additionally, as the largest transmission operator in Indiana, Duke Energy Indiana is extremely active in studying and building the transmission needed for new resources in its territory.

Duke Energy Indiana has also made several enhancements and updates to its energy efficiency program offerings. The Company has worked with the low-income collaborative to streamline and improve income-qualified offerings, including adding new measures to increase program reach and impacts. In addition, the Company implemented the Smart $aver Residential offering, which encourages builders to incorporate higher efficiency standards into new single- and multi-family homes, it expanded the reach of the Business Energy Saver program (formerly "Small Business Energy Saver"), and it added an outdoor lighting modernization program to encourage the transition to light-emitting diode ("LED") technology.

Since submitting its 2021 IRP, the Company has also added a new demand response program to its portfolio and modified one of its existing programs, extending its customer reach. Residential customers with smart thermostats can earn bill credits by participating in Power Manager's Bring Your Own Thermostat option. As of March 31, 2024, there were 34 MW in the program, largely incremental to the Power Manager air conditioner switch program. June 2024 saw the launch of Savings On Demand for large customers. With three-year contracts, technical curtailment planning assistance, real-time monitoring, and attractive incentives, the program is intended to attract longer term commitments, provide greater benefits to customers, and give the Company more assurance that the load flexibility will be available when needed.

Finally, Duke Energy Indiana has made advances on rate design, including electric vehicle ("EV") and clean energy programs, and voltage optimization. After completing Phase I of the rollout of its Integrated Volt-Var Control ("IVVC") program in 2022, deployment moved to Phase II to enable voltage reduction capabilities for nearly 70% of current baseload. The Company has proposed new, widely available time-of-use ("TOU") rates in its most recent rate case, as well as an EV Make-Ready Credit program and enhancements to the GoGreen Indiana clean energy program. In August 2023, the Company brought online its Park & Plug fast charging program, and in October 2024, the Indiana Utility Regulatory Commission ("IURC" or the "Commission") approved the Company's Green Source Advantage ("GSA") rider, which allows eligible non-residential customers to secure renewable energy certificates to match their energy needs with renewable, carbon-free energy. More information on all demand-side activities can be found in Appendix H (Demand-Side Resources & Customer Programs).

Overview of Short-Term Actions

The execution actions that the Company plans to take in the short term are consistent with the Preferred Portfolio. These steps are summarized in Table 6-1 below.

Table 6-1: Short-Term Action Plan Summary

Resource	Capacity Additions	Proposed Short-Term Actions 2024-2027
Combined Cycle	2,876 MW	• 2024-2025: File Certificate of Public Convenience and Necessity ("CPCN") for two Cayuga 1x1 CCs at 719 MW each to be in-service beginning of year ("BOY") 2030 and 2031; completed in 2024: submitted air permits, MISO Generator Replacement Requests ("GRR") for Cayuga units 1 and 2, and incremental capacity study requests • 2025–2026: File CPCN for Gibson 2x1 CC at 1,438 MW to be in-service BOY 2032, submit air permits, submit MISO GRR for Gibson units 3 and 4
Solar	499 MW	• 2024-2025: Procurements targeting approximately 300 MW of solar to be in-service by 2030 • 2025: Speedway Solar (199 MW) placed in-service by end of year
Storage	400 MW	• 2024-2025: Procurements targeting 400 MW of battery storage, which could be standalone, paired with solar, or a combination of the two to be in-service by 2030
Energy Efficiency	155 MW	• 2025: File for new three-year energy efficiency programming • 2025-2027: Continue to grow existing programs and introduce new cost-effective programs
Demand Response & Voltage Optimization	38 MW	• Continue to grow existing demand response programs and introduce new cost-effective programs, apply lessons learned to Savings on Demand program • Continue deployment of IVVC to additional circuits • Monitor changes to MISO and Federal Energy Regulatory Commission ("FERC") policies, participate in forums and utility groups

Natural Gas Conversion / Co-firing	N/A	• 2025-2026: Complete boiler natural gas co-firing and conversion studies for Gibson units 1-4 • Complete Edwardsport CCS Feed Study by mid-2026 • 2026-2027: Determination of Edwardsport natural gas conversion or CCS path and timing
SMR	N/A	• Continue work with Purdue University related to advanced nuclear feasibility • Monitor developments in advanced nuclear technology, continue other preliminary discussions and activities, such as preliminary siting study and industry engagements
Rate Design	N/A	• 2024-2027: Ramp up implementation of Green Source Advantage and other voluntary customer clean energy programs • If approved, implement new time-of-use rates and electric vehicle programs
Transmission	N/A	• Participate in the LRTP process as a transmission operator • Continue engagement with MISO and stakeholders to reform MISO transmission interconnection queue process and timing

The cost of the Preferred Portfolio is discussed in Chapter 4 (Candidate Resource Portfolios), Chapter 5, and Appendix C (Quantitative Analysis). Cost estimates for new resources by resource type are presented in Appendix F (Supply-Side Resources).

Demand-Side Resources

Duke Energy Indiana's initiatives for demand response, energy efficiency, and other customer programs will continue to advance options that allow for overall demand reduction and demand optimization, helping to manage growing customer needs over the 20-year planning period. As part of these efforts, the Company will monitor potential changes in how load modifying resources are valued in MISO markets and will actively participate in MISO forums and utility groups to help shape these changes. In addition, the Company will follow indications of how FERC Order 2222, which seeks to enable distributed energy resources to participate in regional grid operator markets, may be implemented at both the FERC and MISO levels to inform a strategy to maximize benefits for the Company and its customers.

Details on demand-side activities that occur through stakeholder and regulatory proceedings outside of the IRP process, as well as forecasted demand-side resources included in the 2024 IRP, are found in Appendix H.

Energy Efficiency

Duke Energy Indiana will continue to implement the suite of programs as filed and approved in Cause No. 45803. The Company will begin working on a 2027-2029 energy efficiency portfolio plan consistent with the Preferred Portfolio in early 2025 to be filed later in 2025. The Company will also continue to work with its Demand-Side Management ("DSM") Oversight Board ("OSB") to explore ways to expand and improve upon energy efficiency and demand-side management programs, making them more attractive and available for more customers, both residential and non-residential. Finally, Duke Energy Indiana will continue to coordinate with the Indiana Office of Energy Development to assist customers in accessing Inflation Reduction Act ("IRA") funds and complementary utility incentives to overcome economic barriers they may face in investing in energy efficiency measures.

Demand Response

The Preferred Portfolio includes programs that are approved by the Commission, at budgets approved by the Commission. To the extent it is cost-effective, the Company intends to grow its demand response capability through both existing programs and new ones. Additional details on the Company's demand response activities are provided in Appendix H.

Rate Design

In addition to the GSA program recently approved by the Commission, the Company has proposed a Make-Ready Credit to facilitate electric vehicle adoption by residential customers, new TOU rates for residential, commercial and industrial customers, closing the existing Low Load Factor Secondary Service rate to new participants and replacing it with an improved design, and enhanced new large load financial risk mitigation measures in formal filings before the Commission. These programs will be implemented as they are approved, and the impacts will be reflected in future IRP load forecasts. Duke Energy Indiana is also wrapping up four two-year electric vehicle programs aimed at supporting EV adoption in the state and evaluating the system impacts of different electric vehicle types. These programs have provided valuable insights for managing EV charging load, which the Company intends to leverage in developing cost-effective EV load management offers. Additional details on the Company's existing and proposed rate design programs are provided in Appendix H.

Voltage Optimization

The Company is currently deploying Phase II of its IVVC program, which will extend voltage reduction capabilities to an additional 10% of circuits. The IVVC deployment, which supports the implementation of the Preferred Portfolio, is described in Appendix H.

Supply-Side Resources

This section provides more information on the short-term actions for supply-side resources associated with the execution of Preferred Portfolio. It also discusses potential course adjustments that the Company could make in response to changing market or regulatory conditions, including potential changes to requirements or deadlines under the EPA CAA Section 111 Rule.

Resource Procurement

Procurement of the supply-side resources in the Preferred Portfolio will be executed in a manner that preserves customer value by pursuing the most reasonable, least-cost solution across each procurement action the Company undertakes. The Company utilizes a competitive procurement process, described in detail in Appendix G (Competitive Procurement Process), to solicit bids for resources. In all cases, the information gained through the procurement process will be used to inform and refine future resource planning analyses and filings. This ongoing, iterative process, in which subsequent procurement efforts and their associated regulatory proceedings inform future IRPs will provide the Company with opportunities to adjust the pace and volumes of procurement activities in response to changing market conditions relative to planning assumptions at any given point in time. It is from this competitive procurement process that the Company selects the best projects to meet future resource needs, including those referenced in the actions listed below.

Renewable Energy & Battery Energy Storage

The addition of new solar resources and battery storage capacity is a key component of the Company's Short-Term Action Plan. While the capacity value of wind and solar is expected to diminish over time as these resources make up an increasingly large share of the MISO resource mix, the energy these resources produce will help mitigate fuel cost and supply risk while improving environmental sustainability. Battery energy storage provides capacity to complement the energy generated by renewables and shift it in time, allowing that energy to be available at times that align with customer needs. Duke Energy Indiana is planning to add approximately 499 MW of solar to its system by 2030 and approximately 400 MW of battery energy storage by 2030 to meet customer needs in the near term. The Company is already taking steps to secure these resources with an approved power purchase agreement for the 199 MW Speedway Solar project, which is scheduled to be in-service by the end of 2025. The Company will procure additional renewables and battery energy storage through the competitive process described above. While wind energy resources do not appear in the Short-Term Action Plan, the Preferred Portfolio calls for substantial wind capacity to be added in the second half of the planning period. The Company will continue to monitor the market for these resources over the next several years.

Federal Policy & Regulatory Risks

Tariff risk associated with non-domestic supply of solar modules is on the rise, contributing to growing uncertainty and disruption in the solar supply chain. While tariffs aim to protect domestic industries, they can also harm domestic manufacturers who rely on imported components, potentially undermining the development of a robust domestic supply chain. On April 24, 2024, the American Alliance for Solar Manufacturing Trade Committee filed antidumping and countervailing duty petitions on U.S. imports of crystalline silicon photovoltaic cells, whether or not assembled into modules, from Cambodia, Malaysia, Thailand, and Vietnam. This is in addition to existing tariffs on Chinese manufacturing.

On May 14, 2024, President Biden announced the tariff rate on solar cells manufactured in China will increase from 25% to 50%, under Section 301 of the Trade Act of 1974. President Biden's two-year exemption on solar tariffs was set to expire in June 2024.

The Company will continue to monitor impacts to project costs and lead times as it evaluates potential projects through its competitive procurement process.

Permitting & Community Support

Counties within Indiana are increasingly adopting ordinances that establish an approval process and development standards for a wide array of utility-scale renewable energy facilities. A growing number of counties are imposing moratoriums on these facilities until such ordinances are approved and implemented. Due to moratoriums and the vast disparities among local policies, siting new renewable resources will be challenging. In many cases, local policy greatly limits renewable energy generation siting and/or usable acreage, increases project-related capital costs, or halts implementation of a specified resource type altogether. Local voices have been the primary drivers for the enactment of these local policies. The Company can help build local community support through early discussion with community members, coupled with robust education, and potentially regulatory or policy support. Hoosiers' support will be critical to achieving the desired new renewable generation resource developments as planned.

Cayuga Generating Station

Replacement of the Cayuga coal units 1 and 2 with two 1x1 combined cycle ("CC") generators includes the following short-term actions:

- File an air permit application. This was completed in the first half of 2024.
- Submit the needed transmission interconnection agreement requests with MISO, including a Generator Replacement Request to reuse the retiring coal units' interconnection rights, and enter the MISO generator interconnection study process for the approximate 440 MW of incremental capacity that the new combined cycle units will provide. Both of these items were completed in the first half of 2024.
- File a Certificate of Public Convenience and Necessity proceeding with the Commission to seek approval of the two 1x1 combined cycle generators.
- Secure firm gas supply to Cayuga site.

Gibson Generating Station

Gibson Units 1 & 2

The upgrade of Gibson units 1 and 2 to allow co-firing for natural gas and coal includes the following short-term actions:

- File the necessary environmental permit applications.
- Perform a detailed engineering study to refine the co-firing configuration, expected performance characteristics and cost of the upgrade.
- File for approval of the co-firing upgrades with the Commission.
- Secure firm gas supply to Gibson site.

As described in Chapter 5, any changes to requirements or deadlines under the EPA CAA Section 111 Rule could make it prudent to delay the implementation of co-firing on Gibson units 1 and 2.

Gibson Units 3 & 4

The replacement of the Gibson 3 and 4 coal units with a 2x1 combined-cycle generator includes the following short-term actions:

- File the necessary environmental permit applications.
- Submit a Generator Replacement Request with MISO to reuse the retiring coal units' interconnection rights.
- File a Certificate of Public Convenience and Necessity proceeding with the Commission to seek approval of the 2x1 combined-cycle generators.
- Secure firm gas supply to Gibson site.

Labor and supply chain constraints for natural gas generation resources continue to have an impact on project costs and lead times. The EPA CAA Section 111 Rule requiring that all utilities in the country transition out of coal by the early 2030s contributes to these pressures. The Company will closely monitor any changes to cost and lead time estimates for the planned 2x1 CC at Gibson over the coming months and will use that information along with updates to the load forecast to assess whether a pivot to natural gas conversion of these units is warranted. In the event that a course adjustment is reasonable and prudent, conversion of Gibson units 3 and 4 to 100% natural gas fuel would allow continued operation in compliance with the EPA CAA Section 111 Rule. In the event of a delay in the requirements under the EPA CAA Section 111 Rule, the Company would reevaluate the appropriate timing of action at Gibson units 3 and 4.

Edwardsport Integrated Gasification Combined Cycle Plant

To maintain future optionality for the Edwardsport IGCC to either convert to 100% natural gas-firing or add carbon capture and sequestration includes the following short-term actions:

- Perform a detailed engineering study to optimize firing on 100% natural gas by 2030, and determine needed modifications, performance characteristics, retirement scope of the gasifiers, and cost.
- Continue to advance studies in support of eventual CCS by 2032.

As described in Chapter 5, any change to requirements or deadlines under the EPA CAA Section 111 Final Rule could make it prudent to reevaluate the appropriate timing of action at Edwardsport.

Advanced Nuclear

The United States advanced nuclear market continues to progress with many different reactor technologies under current development, and Duke Energy Indiana’s affiliates in the Carolinas are leaders in nuclear generation operation. The possibility of considerable cost declines as SMR technology, supply chain, and regulatory processes mature, combined with the potential future value of reliable, around-the-clock, carbon-free generation, makes it prudent for the Company to continue to advance early studies necessary to keep advanced nuclear a viable option for future resource plans.

A nuclear siting study is being performed by an independent firm for the Duke Energy Midwest service territories. The approach is similar to a previous study utilizing Electric Power Research Institute (“EPRI”) and Nuclear Regulatory Commission (“NRC”) guidance. This multi-faceted approach considers energy communities as defined by the IRA along with environmental and physical factors such as cultural resources, wildlife areas, seismology, topography, geology, and hydrology. The results will inform potential locations that are suitable for nuclear power plant construction, without presupposing a reactor technology. The study is targeted to be completed in December 2024. Additional detail on advanced nuclear resources is provided in Appendix F.

Fuel Supply

Duke Energy Indiana's natural gas supply strategy is critical to ensuring adequate energy and capacity to support economic development growth, maintain system reliability and stability, and reduce cost and risk associated with the aging coal fleet. Duke Energy Indiana’s customers have long benefited from a secure and diverse portfolio of coal and natural gas energy sources, and more recently renewables and energy storage. As the generation portfolio transitions away from aging coal-fired facilities, efficient and flexible natural gas generators will become even more important, alongside growing contributions from energy storage. Securing additional firm transportation (“FT”) for natural gas fuel is an essential component of the Short-Term Action Plan to provide the natural gas supply security needed for reliable, cost-effective generation.

Managing Transmission Interconnection Risk

MISO is responsible for studying generation interconnection projects and the effects on the bulk electric system. This involves coordination with transmission owners on mitigations or upgrades to accompany new generation. Historically, transmission interconnection studies have been plagued by substantial delays, which have in turn led to delayed transmission network upgrades to accommodate new generation. These challenges, which extend project lead times for new resources, represent one of the greatest risks to successful plan execution. For this reason, development status, including interconnection status, is a key consideration when evaluating bids submitted to the Company's resource solicitations.

Fortunately, Duke Energy Indiana has the opportunity to take advantage of MISO's Generator Replacement Request process for a portion of its new resource needs, mitigating the risk of project delays and costly transmission network upgrades. This process allows the Company to apply to use the transmission rights of Duke Energy Indiana's retiring assets for interconnection of new replacement generation at existing sites using the same electrical point of interconnection, thereby avoiding the MISO Definitive Planning Phase study process. Importantly, approval of a GRR application is most likely when the new generation has characteristics similar to the retiring asset.

Conclusion

The Short-Term Action Plan put forth in this Chapter details a schedule of activities and goals developed by the Company to begin efficient implementation of the Preferred Portfolio. The Preferred Portfolio will ensure that the Company will continue to safely, reliably and affordably serve customers in Indiana, providing incremental capacity to support economic development while improving the environmental sustainability of the resource mix.

Appendix A: Stakeholder Engagment

Highlights

- Stakeholder engagement is a vital process for making Duke Energy Indiana a strong and responsive community partner. The Company recognizes the diverse views of stakeholders on how Duke Energy Indiana should transition to cleaner energy without compromising reliability of service, energy affordability, or the power demands of a growing region.
- To prioritize broad, transparent, and inclusive participation while recognizing that participants had varying backgrounds in key resource planning concepts, Duke Energy Indiana held both public and technical engagement sessions. Over the course of seven months, the Company held five public and five technical meetings with almost 150 individuals, representing about 75 organizations in attendance.
- Stakeholder feedback has been incorporated throughout the development of the Integrated Resource Plan and can be found in the various assumptions and scenarios modeled in the Plan as well as the metrics under which the portfolios were evaluated.

Stakeholder engagement is essential in making Duke Energy Indiana (the “Company") a strong and responsive community partner. The Company believes that considering the needs and concerns of a broad audience of customers, regulators, environmental organizations, social advocates, community agencies, elected officials, employees, and many others is critical for resource planning. In developing the 2024 Integrated Resource Plan (“IRP” or the “Plan”), the Company considered a broad range of diverse perspectives, which were shared during the robust stakeholder engagement effort preceding the filing of the 2024 IRP.

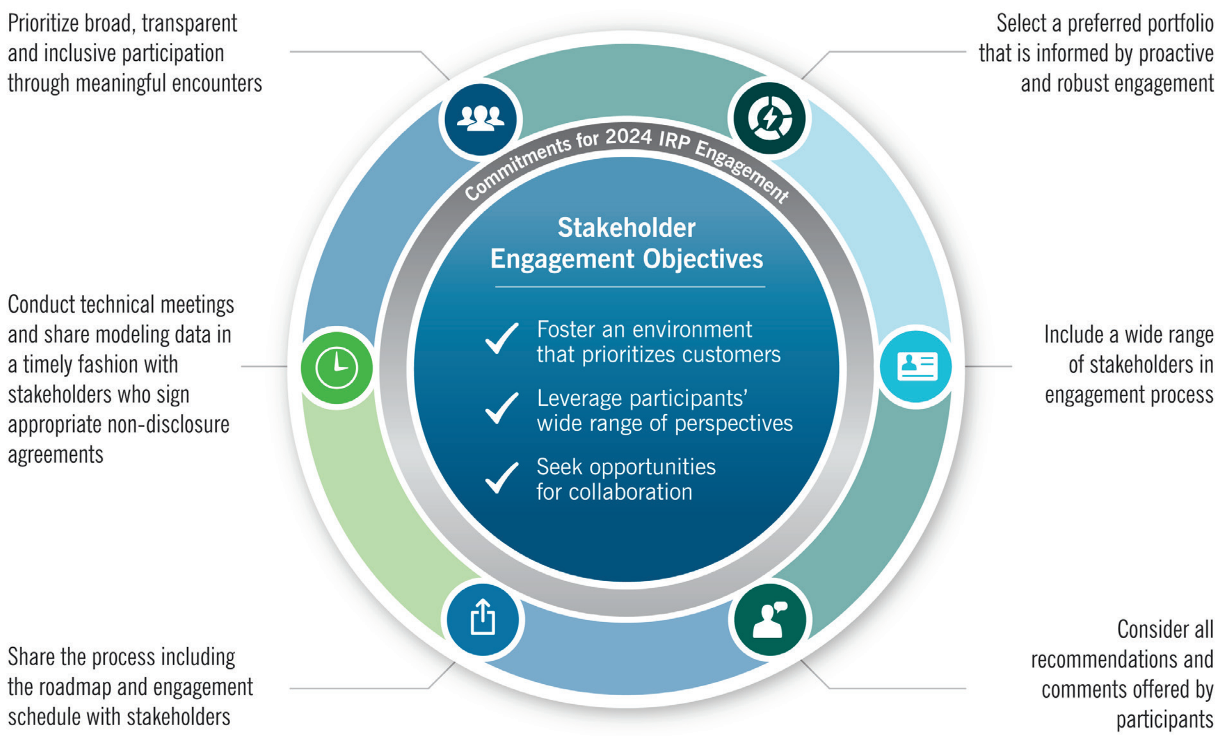
Duke Energy Indiana retained 1898 & Company (“1898”), an experienced third-party consultant and facilitator, to advise the Company in its effort to meaningfully collaborate with interested parties.

Together with 1898, Duke Energy Indiana devoted significant attention to creating a comprehensive engagement process designed to prioritize broad, transparent, and inclusive stakeholder participation.

Foundational Objectives & Commitments to Stakeholders

Duke Energy Indiana incorporated three foundational objectives in its 2024 IRP stakeholder engagement. First, the Company sought to foster an environment that encouraged meaningful conversations and open discussion around resource planning that prioritized reliability, affordability, and increasingly clean energy for customers. Second, the Company leveraged the expertise and experience of stakeholders, recognizing that they represent a wide range of perspectives. Finally, the Company focused on building upon areas of agreement, clarifying areas of disagreement, and pursuing opportunities for collaboration. In support of these objectives, Duke Energy Indiana made several commitments to stakeholders at the outset of the engagement process detailed in Figure A-1 below.

Figure A-1: Stakeholder Engagement Objectives and Commitments



Duke Energy Indiana sought to prioritize broad, transparent, and inclusive participation through meaningful encounters by recognizing the diversity among stakeholders. Participants approached this lengthy engagement effort with different backgrounds, objectives and preferences, and the Company focused on creating an environment where open dialogue was encouraged. Participants had several options for sharing information including attending in-person meetings (for sessions one and three); offering verbal comments or asking questions; submitting written questions; or sharing information and links with other participants. Recognizing that some participants were well-versed in technical IRP issues, Duke Energy Indiana hosted a technical meeting prior to each public meeting focused primarily on complex modeling topics.

The Company shared its overall road map and engagement schedule with stakeholders and provided updates as topics or timelines changed. Throughout the engagement process and in preparing the 2024 IRP, Duke Energy Indiana considered all recommendations made by the wide array of stakeholders – including feedback made during meetings as well as that submitted via email and separate stakeholder conversations – and incorporated much of that feedback into its analytics and scorecard. With such a broad spectrum of participants and priorities, however, comes an equally wide array of desired outcomes and interests from invested participants that are sometimes in tension with one another.

Engagement Process

Public Website

At the outset of the engagement process, Duke Energy Indiana established a 2024 Indiana IRP website.[1] This website was used throughout the process to publish meeting materials (slides and post-meeting summaries) and allow all interested parties to register for upcoming public engagement sessions. In addition, this website provided easy access to previous IRP materials and related information.

Invitations

The 1898 team created the initial invitation matrix by combining lists of stakeholders known to Duke Energy Indiana as being historically interested in resource planning issues, including lists previously developed in conjunction with the 2021 IRP as well as the updated IRP modeling that occurred throughout 2022 and 2023. The initial matrix of about 350 individual email addresses was updated throughout the process to include additional interested parties and ultimately included almost 470 individual email addresses. Invitations to each meeting series were sent via email by 1898 and registration information was made available on the 2024 Indiana IRP website. Emails reminding potential participants to register for the public meetings were sent throughout the engagement process.

Technical Representative Designation

Recognizing that meeting attendees would likely have varying backgrounds in key resource planning concepts, Duke Energy Indiana offered both a public and a technical meeting in each series of the engagement. Invitations to the public meetings offered attendees the opportunity to self-identify as a

[1] Duke Energy, Indiana Integrated Resource Plan, available at https://www.duke-energy.com/home/products/indiana-integrated-resource-plan.

"technical representative" and participate in a separate technical meeting. Technical representatives were defined as those who, by virtue of their direct experience, are qualified to provide expert testimony before a utility regulatory commission or similar tribunal in resource planning concepts such as, but not limited to, utility load forecasting, resource adequacy analysis, evaluating energy tax credits, etc. Technical representatives were provided access to detailed modeling files and data as discussed later in this Appendix and, as such, were required to execute a non-disclosure agreement ("NDA").

Meetings

Public Meetings

Public meetings were held virtually except for the first and third meetings, which included an option for stakeholders to participate in person at the Duke Energy Indiana Plainfield office. Recognizing that stakeholders have varying levels of experience, the early public meetings included presentations introducing foundational resource planning concepts and objectives. Presenters and attendees engaged in high-level discussions of modeling and input assumptions, scenario development, and several other resource planning concepts described further below in the engagement series summaries.

Given such broad participation, establishing ground rules early in the public engagement series was important. Each meeting opened with an overview of the ground rules, which emphasized the importance of collectively upholding respect for one another's experiences and opinions, even in difficult conversations. Participants were asked to focus on the scope of the topics covered in that meeting's agenda in order to make the best use of the group's time. Finally, participants were asked to respect the "Chatham House Rule," which prevents participants from publicly attributing any particular statement or comment to a specific individual.

During designated periods in the public meetings, attendees had the opportunity to participate by asking questions, making comments and otherwise sharing information. In the hybrid meetings, microphones were available to those who attended in person so that all in-person and online attendees could hear the question or comment being made. Online attendees in all public meetings submitted questions to presenters using the question and answer feature in Teams. Questions were displayed for all attendees to see and, as time permitted, they were addressed by presenters. Online participants were also able to use the "raise hand" feature in Teams and, when called upon, they were able to unmute to ask a question or make a comment. The chat feature was also enabled throughout the public meetings for sharing information and resources with other participants.

Beginning in the second series, each public meeting included several slides that detailed the feedback, questions or requested information from participants in the preceding public meeting and paired them with the corresponding section in the current meeting that would address the topic. For topics not covered by agenda topics or dedicated slides in the current meeting, detailed written responses were provided.

The Public Sessions were well-attended, with almost 150 unique individuals representing about 75 organizations attending at least one of the meetings. Figure A-2 below illustrates the attendance throughout this process.

Figure A-2: Public Meeting Attendance

Technical Meetings

The technical meetings were all held virtually and focused on the more detailed and complex aspects of the 2024 IRP including specific, and sometimes confidential, modeling assumptions. Notice of the technical meetings was sent to the entire invitation matrix; however, as discussed earlier in this Appendix, only those participants who self-identified as technical representatives and executed an NDA received a link to attend the virtual technical meetings. While many of the topics in the technical meetings were the same as the public meetings, the technical meetings sought to dive deeper into the more complex and detailed resource planning modeling assumptions and methodologies. Participants asked questions and opined on complex resource topics discussed later in this Appendix including, but not limited to, load forecasting, resource cost and availability, enhanced reliability evaluation, Midcontinent Independent System Operator ("MISO") Direct Loss of Load proposal, seasonal accreditation study, evaluating energy-related tax credits, incorporation of federal policy changes into generation strategies, and others.

Additional Meetings

Duke Energy Indiana held smaller meetings focused on topics of importance to individual stakeholders or stakeholder groups. In the seven months preceding the filing of this 2024 IRP, Duke Energy Indiana participated in about a dozen such meetings. Feedback from these additional engagement activities was reviewed, considered and, where possible, incorporated into this 2024 IRP as if it had been provided during one of the broader sessions.

Other Engagement

Duke Energy Indiana's stakeholder engagement continued outside of the Technical and Public Sessions. Stakeholders had the opportunity to provide feedback by sending emails to a dedicated email address (DEIndianaIRP@1898andco.com) monitored by 1898 who responded to each of these emails acknowledging the input and passed it along to the Company for review and response, as appropriate. More than 100 substantive emails were sent by stakeholders, which were reviewed and responded to by 1898 and Duke Energy Indiana.

Information Sharing

Public Meeting Slides & Summaries

At least seven days prior to each public meeting, copies of presentation materials were uploaded to the 2024 Indiana IRP website and an email was sent to the invitation matrix providing prospective attendees with access to the materials and reminding them to register for the meeting. After the meetings, detailed summaries were also uploaded to the 2024 Indiana IRP website and participants received a reminder of their posting via email after the meetings. These summaries provided a recap of each topic discussed and provided an anonymized list of the questions, comments and suggestions made by stakeholders as well as, where one was warranted, the response provided by Duke Energy Indiana. Detailed meeting summaries as well as the materials from the public meetings are attached hereto as Attachment A-1 and remain available on the 2024 Indiana IRP website.

Technical Modeling Data & Files

Throughout the engagement process, technical representatives were provided access to the EnCompass modeling files and other relevant data and inputs used in developing the 2024 IRP. More than 650 individual files were shared through Datasite, and technical representatives were provided access information via email. Attachment A-2 provides a detailed list of the technical modeling data and files shared throughout the engagement process, the dates the information was available on Datasite, and a summary of the emails sent to stakeholders notifying them that the data was available. In addition, the Company provided detailed written responses to specific stakeholder questions, including providing additional planning data, throughout the engagement process.

Feedback Review, Consideration, & Incorporation

A diverse array of individuals and organizations actively participated in the engagement effort and provided Duke Energy Indiana with hundreds of pieces of feedback in advance of filing the 2024 IRP. It is important to recognize that the interests, ideas and desired outcomes of such a broad range of stakeholders sometimes conflict, so, while it is impossible to incorporate each and every recommendation, stakeholder feedback was essential in shaping the 2024 IRP and Duke Energy Indiana reviewed and considered every comment and recommendation by stakeholders in this process. Many adjustments were made to the Company's planning assumptions and scorecard metrics based on this robust feedback. The 2024 IRP also includes a generation strategy developed in collaboration with several stakeholders (Exit Coal Earlier (Stakeholder)), as well as an alternate planning scenario evaluated at the request of another stakeholder group ("Deep Decarbonization and Rapid Electrification"). A detailed discussion of specific adjustments made based on stakeholder recommendations is provided later in this Appendix in the Incorporation of Stakeholder Feedback in the IRP section.

Engagement Series

As discussed earlier in this Appendix, the technical and public meetings began in February 2024 and the five-part engagement series continued over an eight-month period. The meetings were well attended with about 150 individuals representing about 75 organizations attending public and technical meetings covering a range of resource planning topics. Stakeholder participation in these sessions was instrumental in the development of the 2024 IRP. The summaries below of each engagement series is intended to provide an overview of the topics discussed.

First Engagement Series

The first technical meeting was held virtually on February 6, 2024, and the first public meeting was held in person at Duke Energy Indiana’s Regional Headquarters in Plainfield, Indiana, with the option to attend virtually, on February 22, 2024. This first series set the stage for the engagement effort and provided an overview of some of the fundamental aspects of the 2024 IRP. Both meetings in the first series included discussions of the key policies that would influence the Company’s 2024 IRP, such as incorporation of tax incentives under the Inflation Reduction Act of 2022 (“IRA") in modeling assumptions, as well as an overview of the effect of the Environmental Protection Agency’s (“EPA”) then-proposed rule under Clean Air Act (“CAA”) Section 111. The meetings both included conversations around the proposed scenario development process and potential scorecard metrics. Participants in both sessions provided extensive feedback on the proposed scorecard metrics, which helped inform the final scorecard.

The technical meeting included a detailed discussion of the resource capacity values used in long-term planning and provided a comparison of unit-level unforced capacity (“UCAP”) values with Midcontinent Independent System Operator Seasonal Accreditation Capacity values.

The public meeting began with welcoming remarks from Stan Pinegar, Duke Energy Indiana’s state president. This meeting included a summary of the 2021 IRP, including subsequent updated modeling; planned enhancements for the 2024 IRP; and an overview of MISO. Figure A-3 below lists the presenters and topics discussed at the first series technical and public meetings.

Figure A-3: First Engagement Series Presenters and Topics

Presenters

- **Bryan Garnett** ■ ■
  RTO & Compliance Manager
- **Matt Kalemba** ■ ■
  Vice President, Integrated Resource Planning
- **Matt Peterson** ■
  Resource Planning Manager
- **Jennifer Poppler** ■ ■
  Principal Planning Analyst
- **Taylor Meredith** ■ ■
  Federal Government Affairs Director
- **Vicky Sullivan** ■ ■
  Climate Policy Director

■ *Technical Session* ■ *Public Session*

Key Topics Covered

- **EPA's CAA Proposed Update** ■ ■
- **Incorporating the IRA** ■ ■
- **Resource Accreditation/ Adjusted UCAP** ■ ■
- **2024 IRP** ■ ■
  - *Scenario Development*
  - *Planning Objectives*
  - *Potential Measures*
    - *Environmental Sustainability and Affordability*
    - *Reliability, Resiliency and Stability*
    - *Risk and Uncertainty*

Second Engagement Series

The second technical meeting was held on April 25, 2024, and the second public meeting was held on April 29, 2024. Both meetings in this series were held virtually. Based on feedback from technical representatives in the first series, subsequent technical meetings were held only a few days in advance of public meetings so that technical representatives had the opportunity to download and review current modeling data forming the basis of public meeting discussions. Both meetings included presentations and discussion around Duke Energy Indiana's anticipated load forecast, as well as an overview of the process for developing the Market Potential Study ("MPS") for demand-side resources. Both sessions also addressed the Company's supply-side resources and fuel assumptions, and a preview of the scenario and Generation Strategies planned in the 2024 IRP.

The technical meeting included deeper dives into the modeling inputs but did not include any topic areas not otherwise covered in the public meeting. The public meeting included a recap of the feedback received from stakeholders in the previous session, as well as an explanation of how Duke Energy Indiana would be addressing that feedback in the current meeting or otherwise had considered it in developing the 2024 IRP. This public meeting included an introductory discussion on the fundamentals of an IRP and the process in Indiana. The community engagement team provided an overview of Duke Energy Indiana's deep-rooted history of community and infrastructure engagement and highlighted the contributions the Company made to the Indiana communities it serves in 2023. Duke Energy Indiana provided an overview of the load forecast scenarios being developed for the 2024 IRP and how assumptions around economics, electric vehicles, behind-the-meter solar, and economic development are being considered in the load forecast.

Based on feedback from the previous public meeting, Duke Energy Indiana provided an overview of its demand-side resources and customer programs and announced that a separate meeting fully focused on customer programs would be held over the summer. The Company provided an overview of the MPS, its resource capital cost assumptions (the Generic Unit Summary) and forecasted fuel price curves, and then discussed how these are incorporated in the 2024 IRP. The 1898 team engaged participants in a discussion of the planning reserve margin and explained the role of MISO’s annual Loss of Load Expectation study in resource planning. Duke Energy Indiana then previewed the revised metrics to be used in evaluating potential portfolios. These scorecard metrics were informed significantly by stakeholder feedback in the previous engagement series. Figure A-4 below lists the presenters and topics discussed in the second engagement series.

Figure A-4: Second Engagement Series Presenters and Topics

Presenters

- **Rush Childs**
  Manager, Advisory Services, Resource Innovations
- **Kristen Cooper**
  Lead Engineer
- **Bryan Dougherty**
  Principal Structuring Analyst
- **Nate Gagnon**
  Managing Director, IRP & Analytics
- **Zak Kuznar**
  Managing Director Grid Solutions Development
- **Patrick O'Connor**
  Lead Quantitative Analyst
- **Jay Oliver**
  Managing Director Energy Storage & Grid Development
- **Matt Kalemba**
  Vice President, Integrated Resource Planning
- **Joseph Phalen**
  Principal Load Forecasting Analyst
- **Phil Stillman**
  Managing Director Load Forecast
- **Tiffany Weir**
  Director Rates & Regulatory Filings
- **Bryan Wright**
  Lead Structuring Analyst

Technical Session *Public Session*

Key Topics Covered

- **Stakeholder Feedback & Incorporation**
- **IRP Fundamentals**
- **Community Engagement**
- **Load Forecast**
- **Grid Edge & Customer Programs**
- **Demand-Side Management Market Potential Study**
- **Supply-Side Resources**
- **Fuels**
- **Accreditation/Reserve Margin & MISO Modeling**
- **Scenario & Generation Strategies Review**
- **Final Scorecard Metrics Review**

Third Engagement Series

The third technical meeting was held on June 18, 2024, and the third public meeting was held on June 20, 2024. Both meetings in this series were held virtually. Both meetings included a discussion of how Duke Energy Indiana was incorporating the EPA CAA Section 111 May 2024 Final Rule into its 2024 IRP modeling and provided a preview of preliminary resource portfolio results.

During the technical meeting, members of the Duke Energy modeling team answered questions from stakeholder technical representatives about the EnCompass modeling files and data that had been uploaded to Datasite in advance of the meeting.

As with the second series, the third public meeting included a review of the feedback received from stakeholders in the previous public meeting and a description of how Duke Energy Indiana would be addressing it in the current meeting or otherwise had considered it in developing the 2024 IRP. Additionally, the third public meeting included a discussion of the 2024 IRP modeling assumptions around MISO energy prices as well as the MPS. Figure A-5 below lists the presenters and topics discussed at the third series of technical and public meetings.

Figure A-5: Third Engagement Series Presenters and Topics

Presenters

- ■ **Rush Childs** *Manager, Advisory Services, Resource Innovations*
- ■ ■ **Nate Gagnon** *Managing Director, IRP & Analytics*
- ■ **Josh Paragas** *Engineer, Resource Modeling*

■ *Technical Session* ■ *Public Session*

Key Topics Covered

- ■ **Stakeholder Feedback & Incorporation**
- ■ **MISO Modeling – IRP Energy Market Prices**
- ■ ■ **Incorporation of 111 in Generation Strategies**
- ■ ■ **Initial Preliminary Portfolios**
- ■ **Demand-Side Management Market Potential Study**
- ■ **EnCompass Modeling Files – Q&A with Modelers**

Fourth Engagement Series

The fourth technical meeting was held on August 8, 2024, and the fourth public meeting was held on August 13, 2024. Both meetings in this series were held virtually and included an update on the portfolio modeling, a review of the preliminary scorecard data, and a discussion of the stochastic modeling of energy market exposure. The public meeting included a review of the stakeholder feedback received during and since the third engagement series, and a representative of Charles River Associates provided an update on the ongoing request for proposals ("RFP") process for new supply-side resources. Figure A-6 below lists the presenters and topics discussed at the fourth series technical and public meetings.

Figure A-6: Fourth Engagement Series Presenters and Topics

Presenters

- ■ ■ **Nate Gagnon**
  Managing Director, IRP & Analytics
- ■ ■ **Ameya Deoras**
  Manager Quantitative Analytics
- ■ **Robert Lee**
  Vice President, Charles River Associates
- ■ ■ **Matt Peterson**
  Resource Planning Manager

■ *Technical Session* ■ *Public Session*

Key Topics Covered

- ■ **Stakeholder Feedback & Incorporation**
- ■ **RFP Update**
- ■ ■ **Updated Portfolio Modeling**
- ■ ■ **Preliminary Scorecard**
- ■ ■ **Energy Market Interaction & Stochastic Modeling**

Fifth Engagement Series

The fifth technical meeting was held on October 1, 2024, and the fifth public meeting was held on October 3, 2024. Both meetings in this series were held virtually and included an overview of Duke Energy Indiana's Preferred Portfolio and the final scorecard. The public meeting included a review of the stakeholder feedback received during and since the fourth engagement series and reviewed the scenario results and short-term action plan considerations. Figure A-7 below lists the presenters and topics discussed at the fifth series of technical and public meetings.

Figure A-7: Fifth Engagement Series Presenters and Topics

Incorporation of Stakeholder Feedback in the Integrated Resource Plan

Attendees were active participants in this robust engagement effort in both the public and technical meetings as well as through the dedicated email address. As discussed earlier in this Appendix, this engagement effort included a diverse group of participants with varying interests, ideas and desired outcomes, contributing to some conflicting recommendations and feedback. Nonetheless, Duke Energy Indiana reviewed and considered the significant volumes of feedback and recommendations of all participants and incorporated much of it into shaping the 2024 IRP.

Feedback Received in the 2021 Integrated Resource Plan Informed this Stakeholder Initiative

In response to feedback received from stakeholders, Duke Energy Indiana benchmarked its previous stakeholder engagement against that of other Indiana utilities leveraging the expertise of its consultant 1898. The Company sought to approach this engagement effort with a tone that encouraged participants to share information and opinions, even if they conflicted with Duke Energy Indiana or other participants. As discussed above, each session began with a review of the ground rules, which emphasized the collaborative environment Duke Energy Indiana sought to prioritize in this engagement effort.

Meeting agenda topics in this stakeholder initiative were largely informed by feedback received during the 2021 IRP, and the Company sought to host substantive sessions that were meaningful to participants of incredibly diverse backgrounds. The Company included a discussion of the objectives of the 2024 IRP in the first engagement series held in February 2022 and, in that session, previewed the initial proposed scorecard metrics. Duke Energy Indiana received feedback during and after the session on those metrics and made several adjustments to the final scorecard metrics based on stakeholder feedback. The Company included discussions of its load forecast methodology, data and assumptions in both the technical and public meetings.

The Company provided access to modeling files and other data assumption and methodology information to technical representatives as it became available throughout the engagement period, and Duke Energy Indiana provided all stakeholders access to meeting agendas and materials at least seven days prior to each public meeting.

Feedback Incorporated from the 2024 Integrated Resource Plan Engagement Effort

Data Sharing

During the first engagement series, several participants echoed comments made in the previous IRP around data information sharing. Specifically, stakeholders requested that Duke Energy Indiana provide more clarity around data sharing and requested that information be shared with technical representatives in advance of the technical meetings. In response to stakeholder feedback provided during the 2021 IRP, the Company outlined its commitments to stakeholders and plans for sharing information at the outset of the first engagement series. As discussed earlier in this Appendix, Duke Energy Indiana uploaded materials at least one week in advance of each public meeting and provided access to more than 650 files to technical representatives via Datasite as information was available.

Portfolio Development & Sensitivity Analyses

Stakeholder feedback was also important in developing potential portfolios in the 2024 IRP, which follow various generation strategies and is discussed in greater detail in Chapter 2 (Methodology). One of these is Exit Coal Earlier (Stakeholder), which as discussed earlier, was a collaborative effort between Duke Energy Indiana and certain interested parties. This stakeholder-driven portfolio incorporates feedback received during the engagement process including the assumption that Duke Energy Indiana transition away from coal fuel more rapidly than contemplated in the other generation strategies. Stakeholders also provided feedback requesting that Duke Energy Indiana model the EPA CAA 111 Final Rule.[2] As detailed in Chapter 5 (Preferred Resource Portfolio) of this 2024 IRP, the Company's Preferred Portfolio incorporates the provisions of the EPA CAA 111 Final Rule.

In addition to Exit Coal Earlier (Stakeholder), the Company developed, at the request of certain stakeholders, an additional resource portfolio tailored to a stakeholder-defined "Deep Decarbonization and Rapid Electrification" vision of the future. This analysis was separate and distinct from the

[2] Stakeholders initially requested Duke Energy Indiana model a portfolio that was compliant with the proposed updates to EPA CAA; however, since the EPA CAA Final Rule was published in May 2024, the Company modeled the final rule.

Generation Strategies and other planning scenarios evaluated in the 2024 IRP, and is discussed in Appendix C (Quantitative Analysis).

Stakeholders provided feedback that the 2024 IRP should include supporting information regarding assumptions for capturing the domestic content bonuses within IRA tax incentives. Stakeholders also suggested that Duke Energy Indiana should provide the full range of cost impacts from stochastics. Both recommendations were incorporated and are discussed in more detail in Chapter 3 (Key Assumptions), Chapter 4 (Candidate Resource Portfolios), and Appendix C.

Scorecard Metrics

Stakeholders played a crucial role in shaping the metrics used to develop the scorecard. Their insights and feedback helped ensure that the criteria were relevant and representative of many of the priorities of participants in the engagement effort. The scorecard metrics are discussed in greater detail in Chapter 2. Throughout the development of the 2024 IRP, Duke Energy Indiana made several specific adjustments to metrics based on stakeholder feedback, including adding and removing scorecard metrics based on stakeholders' feedback. Some examples of adjustments to the scorecard metrics include the following:

- Did not include weighting of the scorecard metrics
- Removed inverter-based resource metric in response to stakeholder feedback that a narrative approach is more appropriate to the stability planning objective
- Removed the energy self-sufficiency metric in response to stakeholder feedback that utilities within MISO do not have to self-supply their own load without any assistance from the market
- Removed the 95th percentile expected net load ramp metric in response to stakeholder feedback that less ramping is not necessarily the goal
- Separated fast start and spinning reserve calculations into two separate metrics
- Changed portfolio diversity calculation to be based on firm capacity rather than installed capacity

Duke Energy Indiana appreciates the significant amount of time and input stakeholders dedicated to this 2024 IRP, and the Company commends stakeholders for their demonstrated respect for the different ideas and perspectives shared throughout the lengthy stakeholder process. Participants ensured that differences of opinion were focused on concepts and ideas and not on individuals. The overall tone and the candor of discussions fostered a collaborative environment in which ideas could be shared in a productive manner. Duke Energy Indiana looks forward to continued collaboration with stakeholders in future IRPs.

Additional Stakeholder Activities

Engaging customers, communities, and other stakeholders is foundational to the Company's business, and the effort related directly to this 2024 IRP represents only a portion of Duke Energy Indiana's comprehensive collaboration with stakeholders. The Company actively seeks and values third-party perspectives across a broad range of other topics, and the 2024 IRP was informed not only by the specific resource planning engagement that is the focus of this Appendix, but also by other subject-matter-related engagement efforts.

During the first few public meetings in this engagement effort, several participants made comments and asked questions related to Duke Energy Indiana's customer programs, which while of critical importance, are only addressed in the context of planning analytics in the 2024 IRP and were not intended to be the focus of this engagement effort. To address this important topic while maximizing time in its 2024 IRP engagement, the Company held a separate session focused entirely on customer programs. In this session, Duke Energy Indiana provided an overview of renewable programs, rate designs, electric vehicle programs, and energy efficiency programs currently available to customers as well as a preview of potential future offerings. The session included an opportunity for participants to recommend programs and share information about programs in other areas of the country.

Duke Energy Indiana prioritizes its engagement with the communities and customers it serves and additional information on the Company's impact in Indiana is further discussed in Appendix K (Community Impact).

Appendix B: Duke Energy Indiana System Today

Duke Energy Indiana (or the "Company") is the largest electric utility in Indiana serving approximately 900,000 electric customers. Its diverse service area spans 23,000 square miles and includes cities, towns, and rural areas in 69 of the state's 92 counties covering North Central, Central, and Southern Indiana. The area is diverse in terms of terrain and vegetation coverage and is comprised of both rural and urban communities. The service territory includes Bloomington, Terre Haute, Lafayette, and suburban areas near Indianapolis, Louisville, Kentucky and Cincinnati, Ohio. Headquartered in Plainfield, Duke Energy Indiana has approximately 2,500 employees located in Indiana and operates numerous facilities throughout the state.

Figure B-1, to the right, depicts the counties served in Duke Energy Indiana's service territory. Municipal utilities and rural electric cooperatives also serve Indiana customers throughout this footprint.

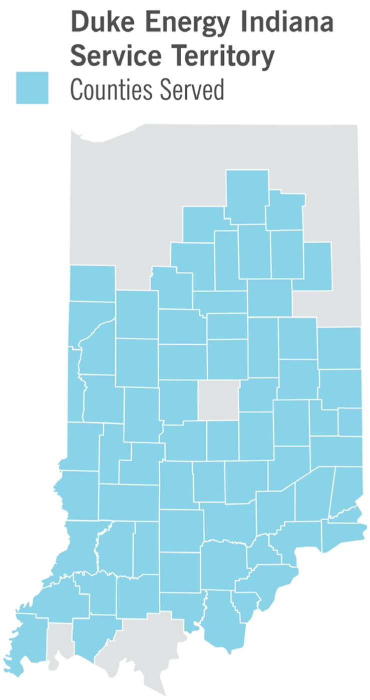


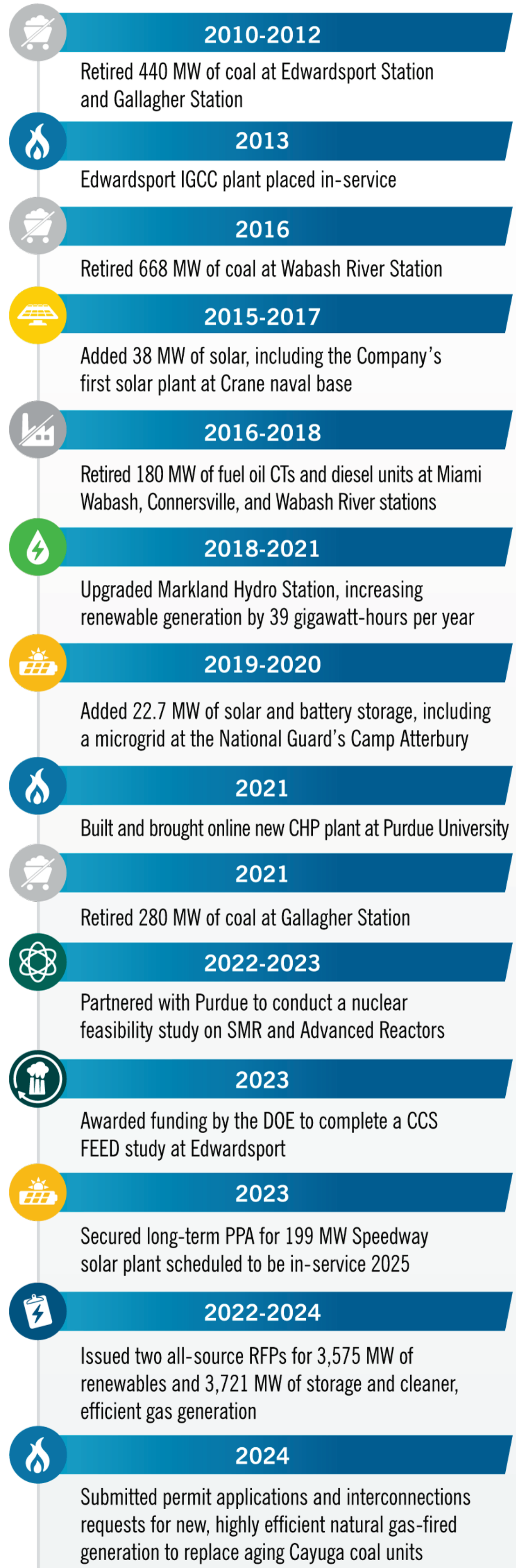
Figure B-1: Duke Energy Indiana Service Territory (right)

Duke Energy Indiana supplies energy to its customers through a mix of baseload and peaking generating units and through purchases. The fuel mix of Duke Energy Indiana's generating assets has and will continue to change over time. Currently, Duke Energy Indiana supports its customers with approximately 6,900 megawatts ("MW") of installed generation capacity comprised of coal, integrated gasification combined cycle ("IGCC"), natural gas, oil, hydropower, solar and wind renewable resources, and storage. The generating fleet includes sites located throughout the state of Indiana and one generating station located in Madison, Ohio. Duke Energy Indiana's generation fleet represents a reliable and dispatchable mix of resources that provides capacity and energy within the Midcontinent Independent System Operator ("MISO") area. The resources comprising this generation fleet are detailed further below.

Evolution of Generating Resource Portfolio

Duke Energy Indiana is continuing its progress to a sustainable energy future. The generation transition is well underway, and the system is changing and expanding. To date, Duke Energy Indiana has retired 12 coal units, accounting for approximately 1,604 MW of installed capacity (1,388 MW summer net capacity), and reduced Scope 1 carbon emissions by over 49% from 2005 levels. Figure B-2 on the right highlights Duke Energy Indiana's steady progress in advancing the energy transition, including the responsible pace of coal retirements.

Figure B-2: Duke Energy Indiana's Ongoing Energy Transition (right)



In just the past three years since the previous IRP, the Company issued two all-source requests for proposals ("RFP") for new generation resources, secured a long-term purchase power agreement ("PPA") for the capacity and energy from a 199 MW solar plant that is scheduled to go in service in 2025, built and brought online new CHP generation at Purdue University ("Purdue"), and started the permitting process for new, highly efficient natural gas-fired generation to replace the aging Cayuga coal units. The Company is also exploring emerging technologies that could play a role in a reliable energy future such as small modular reactors ("SMR") and advanced reactors through a partnership study with Purdue and Carbon Capture and Sequestration ("CCS") through a Department of Energy ("DOE") funding award for a Front-End Engineering Design ("FEED") study at the Edwardsport IGCC facility.

As additional aging coal generation is planned to be retired, Duke Energy Indiana is strategically utilizing cost-effective natural gas and energy storage to provide customers reliable energy and enable a growing renewables portfolio while maintaining a responsible pace of change.

At the same time, Duke Energy Indiana is experiencing unprecedented load growth — historic in both speed and scale — in its service territory. Indiana is growing and attracting economic development, which means Duke

Energy Indiana must adapt its generation mix in the near-term to responsibly meet customers' reliability needs over the long-term. Over time, the Company will replace its aging coal generation with a mix of natural gas, wind, solar, and storage, pending regulatory approval. For example, Duke Energy Indiana will be seeking to install two 719 MW combined cycle units at Cayuga in Vermillion County, Indiana. The first unit would be placed into service by 2030 and the second by 2031, subject to regulatory approval. These units would provide approximately 440 MW of incremental installed capacity by 2031 and complement the addition of an estimated 500 MW of solar and 400 MW of battery storage by 2030.

While Duke Energy Indiana's system and its customer base are growing, the Company remains committed to affordability and reliability for customers and communities throughout the transition to cleaner energy. Beyond the transition of the generation resource mix, the Company connects customers with millions in financial assistance and is ensuring reliability through investments in the transmission and distribution system.

The charts in Figure B-3 and Figure B-4 below depict Duke Energy Indiana's carbon emissions over time, as well as the energy and capacity mix from 2005 to the present.

Figure B-3: Duke Energy Indiana Scope 1 CO_2 Emissions Over Time

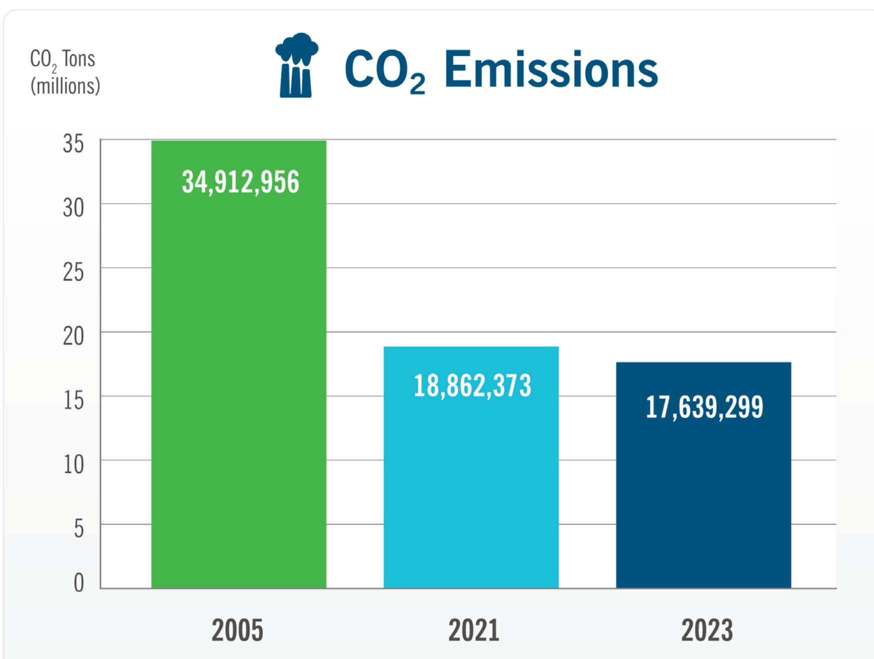
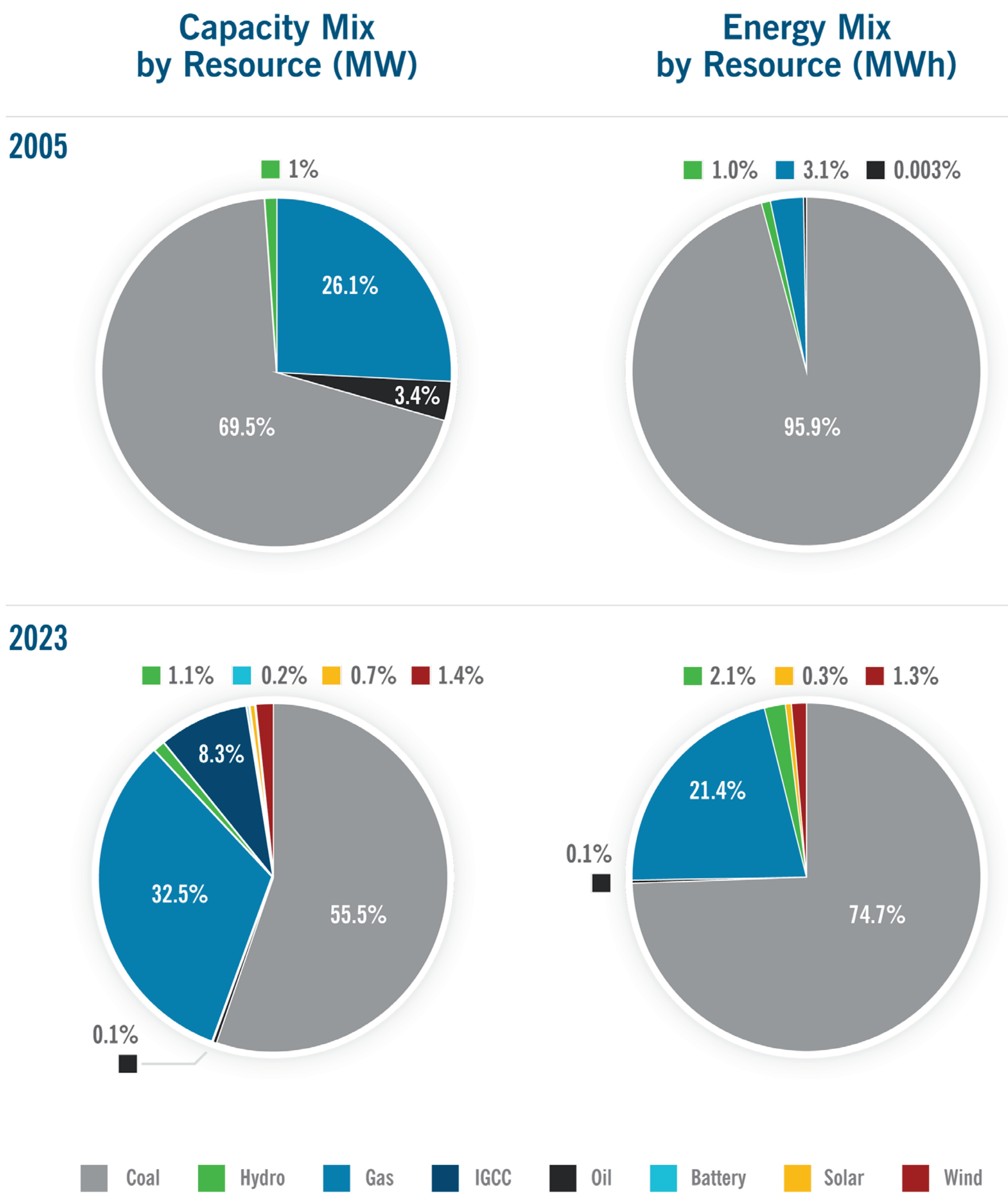


Figure B-4: Duke Energy Indiana Capacity & Energy Mix Over Time

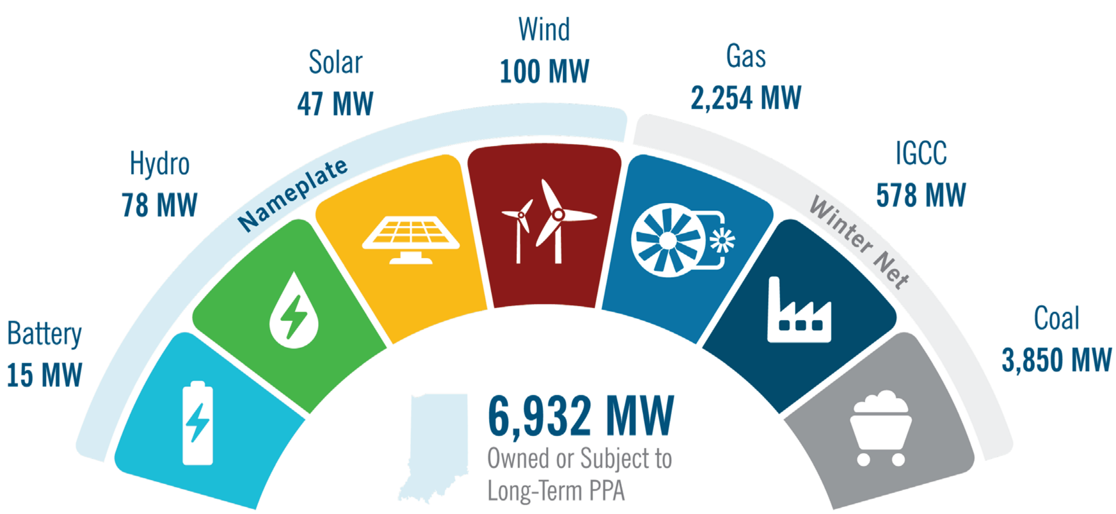


Note: Energy mix in Figure B-4 is shown as percent of total megawatt-hours ("MWh") generation from Duke Energy Indiana portfolio resources. Capacity mix is shown as percent of total installed capacity. IGCC is included in the energy mix as coal.

Current Supply-Side Resources

The total installed supply-side capacity owned or purchased by Duke Energy Indiana is currently 6,932 MW (approximately 6,300 MW winter net). Owned generation consists of coal-fired steam, syngas/natural gas combined cycle, natural gas-fired combined cycle, hydroelectric, natural gas-fired peaking, oil-fired peaking, battery storage, and solar photovoltaic ("PV") capacity. Also included are PPAs with Benton County Wind Farm and five contracted solar facilities. Duke Energy Indiana's owned and long-term purchased capacity by resource type is shown below in Figure B-5.

Figure B-5: 2023 Duke Energy Indiana Supply-Side Capacity by Resource Type



Note: Natural gas capacity in Figure B-5 includes 10 MW of diesel engine capacity.

The coal-fired steam capacity consists of seven units at two stations (Gibson and Cayuga). The syngas/natural gas combined cycle capacity is comprised of two syngas/natural gas-fired combustion turbines and one steam turbine ("ST") at the Edwardsport IGCC station. The combined cycle ("CC") capacity consists of a single unit comprised of three natural gas-fired combustion turbines and two steam turbines at the Noblesville Station. The hydroelectric generation is a run-of-river facility comprised of three units at Markland on the Ohio River. The peaking capacity consists of 24 natural gas-fired combustion turbines ("CT") at five stations (Cayuga, Henry County, Madison, Vermillion, and Wheatland), and four small diesel engines located at Cayuga. One of these natural gas-fired units has oil back-up. Duke Energy Indiana also supplies steam service to one customer from its Cayuga Generating Station, and to Purdue University via a combined heat and power ("CHP") facility.

The solar capacity consists of five solar plants (Crane Naval Station, Camp Atterbury, Tippecanoe, B-Line Heights, and Blue River) as well as power purchase agreements with five solar facilities located near Brazil, West Terre Haute, Kokomo, Sullivan, and Staunton, Indiana. In addition, the Crane Naval

Station and Camp Atterbury solar plants each have a 5 MW battery storage system, and there is a 5 MW standalone battery storage system at Nabb Substation. The wind capacity consists of a 100 MW power purchase agreement with Benton County Wind Farm. Figure B-6 below provides a map of existing Duke Energy Indiana generation facilities. Tables B-1 through B-3 below provide additional information on each facility at the unit level.

Figure B-6: Duke Energy Indiana Generation Facilities

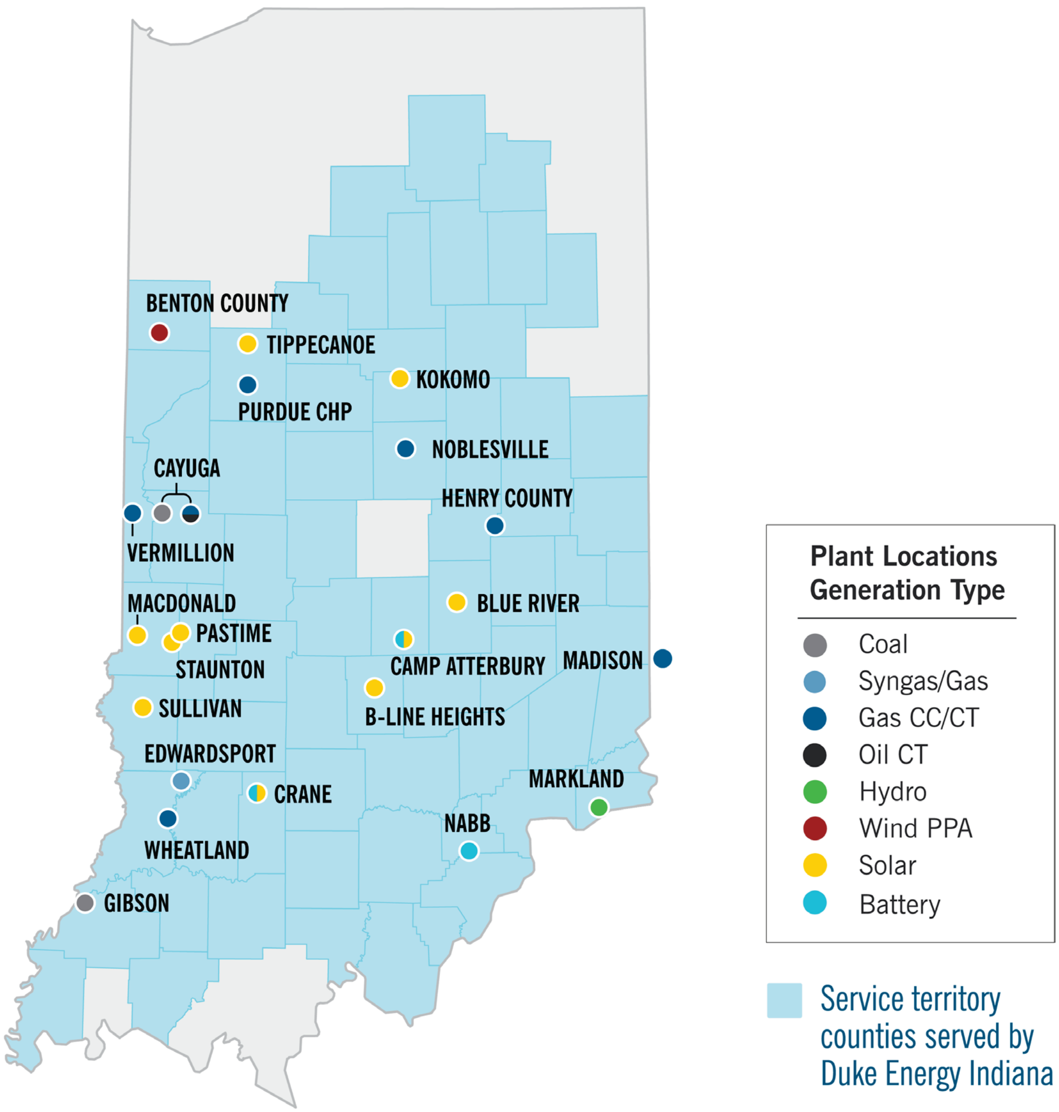


Table B-1: Summary of Existing Thermal Units

Unit	Technology	Nameplate (MW)	Winter Net (MW)	Ownership	In-Service Year
Cayuga 1	Coal	531	505	100%	1970
Cayuga 2	Coal	531	500	100%	1972
Gibson 1	Coal	668	635	100%	1976
Gibson 2	Coal	668	635	100%	1975
Gibson 3	Coal	668	635	100%	1978
Gibson 4	Coal	668	627	100%	1979
Gibson 5	Coal	668	625	50.05%	1982
Edwardsport IGCC	IGCC	805	578	100%	2013
Noblesville CC ST1	Gas CC	50	43	100%	1950
Noblesville CC ST2	Gas CC	50	44	100%	1950
Noblesville CC CT3	Gas CC	61	74	100%	2003
Noblesville CC CT4	Gas CC	61	74	100%	2003
Noblesville CC CT5	Gas CC	61	75	100%	2003
Cayuga Diesel 3a-d	Oil CT	10.4	10	100%	1972
Cayuga CT4	Gas CT	113	105	100%	1993
Henry County CT1	Gas CT	61	40	100%	2001
Henry County CT2	Gas CT	61	47	100%	2001
Henry County CT3	Gas CT	61	47	100%	2001
Madison CT1	Gas CT	87	88	100%	2000
Madison CT2	Gas CT	87	88	100%	2000
Madison CT3	Gas CT	87	88	100%	2000
Madison CT4	Gas CT	87	88	100%	2000
Madison CT5	Gas CT	87	88	100%	2000
Madison CT6	Gas CT	87	88	100%	2000
Madison CT7	Gas CT	87	88	100%	2000
Madison CT8	Gas CT	87	88	100%	2000
Vermillion CT1	Gas CT	87	96	62.5%	2000
Vermillion CT2	Gas CT	87	94	62.5%	2000
Vermillion CT3	Gas CT	87	94	62.5%	2000

Vermillion CT4	Gas CT	87	97	62.5%	2000
Vermillion CT5	Gas CT	87	93	62.5%	2000
Vermillion CT6	Gas CT	87	94	62.5%	2000
Vermillion CT7	Gas CT	87	96	62.5%	2000
Vermillion CT8	Gas CT	87	97	62.5%	2000
Wheatland CT1	Gas CT	125	126	100%	2000
Wheatland CT2	Gas CT	125	126	100%	2000
Wheatland CT3	Gas CT	125	129	100%	2000
Wheatland CT4	Gas CT	125	127	100%	2000
Purdue CHP	CHP	13	16	100%	2021

Table B-2: Summary of Existing Renewables

Unit	Technology	Nameplate (MW)	Net (MW)	Ownership	In-Service Year
Crane Solar	Solar PV	17	17	100%	2017
Crane Battery	Battery	5.0	+/- 5.0	100%	2020
Nabb Battery	Battery	5.0	+/- 5.0	100%	2020
Tippecanoe	Solar PV	1.6	1.6	100%	2019
B-Line Heights	Solar PV	0.1	0.1	100%	2019
Camp Atterbury Microgrid	Solar PV	2.0	2.0	100%	2019
	Battery	5.0	+/- 5.0	100%	2019
Blue River	Solar PV	0.9	0.9	100%	2022
Markland Hydro 1	Hydro	26	26	100%	1967
Markland Hydro 2	Hydro	26	26	100%	1967
Markland Hydro 3	Hydro	26	26	100%	1967

Table B-3: Summary of Existing Renewable Power Purchase Agreements

Unit	Technology	Nameplate (MW)	Net (MW)	Contract Start Year	Contract End Year
Staunton Solar	Solar PPA	4.0	4.0	2019	2029
Pastime Solar	Solar PPA	5.3	5.3	2015	2035
McDonald Solar	Solar PPA	5.3	5.3	2015	2035
Sullivan Solar	Solar PPA	5.0	5.0	2016	2036
Kokomo Solar	Solar PPA	5.6	5.6	2016	2036
Benton County	Wind PPA	100.5	100.5	2008	2028

Transmission & Distribution System

In total, Duke Energy Indiana's electric system includes over 37,000 miles of transmission and distribution lines.

Transmission

Duke Energy Indiana's transmission system currently consists of over 5,200 circuit miles of 345 kV, 230 kV, 138 kV, and 69 kV transmission lines, along with approximately 500 transmission and distribution substations and associated equipment. The Company jointly owns its transmission system with Wabash Valley Power Alliance and the Indiana Municipal Power Agency Duke Energy Indiana's transmission system is under the functional control of MISO, a Federal Energy Regulatory Commission ("FERC")-approved regional transmission organization ("RTO") and is used for the provision of open access non-discriminatory transmission service pursuant to MISO's Open Access Transmission Tariff on file with FERC. As a member of MISO, charges and credits are billed and allocated to Duke Energy Indiana for functional operation of the transmission system, management of the MISO markets, including the assurance of a reliable system, and general administration of the RTO.

Distribution

Duke Energy Indiana's electric distribution system currently consists of over 31,800 circuit miles of distribution lines, as well as control rooms, transformers, circuit breakers, poles, substations, and other associated distribution equipment. The approximately 500 substations mentioned above include both transmission voltage level (20 kV and above) and the lower distribution voltage levels.

Continued Commitment to a Reliable, Resilient, & Stable Grid

Reliability, resiliency, and stability are at the core of Duke Energy Indiana's mission – to render adequate and reliable service and facilities to the public and its customers. The Company has made, and will continue to make, meaningful investment in transmission and distribution assets to ensure and support the electric system's reliability, resiliency, and stability. The Transmission Distribution and Storage System Improvement Charge ("TDSIC") plan and non-TDSIC (e.g., vegetation management, routine maintenance, and expansion) investments that Duke Energy Indiana has made directly contribute to the reliability, resiliency, and stability of its system. Through its TDSIC plans, the Company has invested over $1.6 billion in its electric grid and overall system on behalf of its customers, including advanced technology that has helped prevent more than 185,000 power outages since 2020. The Company has also enhanced its vegetation management plan, including increasing routine trimming. These investments and enhancements have yielded tangible improvements in reliability, as demonstrated in the Company's 2023 performance metrics.

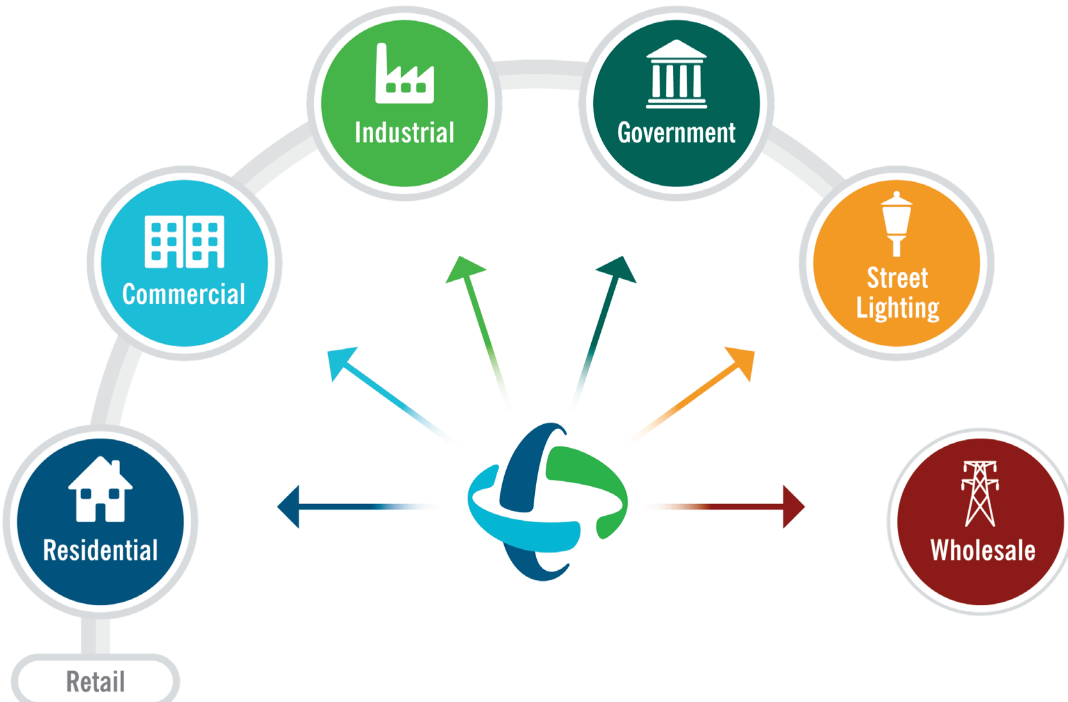
Duke Energy Indiana utilizes reliability data to assess and track the performance of its distribution and transmission systems using generally accepted reliability measures or indices in the electric utility industry. One of the main metrics utilized for both distribution and transmission is System Average Interruption Duration Index ("SAIDI"), which reflects the average number of minutes each customer was without power during a given period. Duke Energy Indiana's overall SAIDI (excluding Major Event Days ("MEDs"))[1] and tree-related SAIDI[2] (excluding MEDs) improved by 30% and 48%, respectively, from 2019. Additionally, the number of Customer Interruptions and Customer Minutes Interrupted reflect material improvement, with reductions of 13% and 27%, respectively, in 2023 as compared to 2019. In this time of rapid change for the electric system, with more extreme weather and challenging conditions, Duke Energy Indiana continues to support reliable power for its customers, investing to minimize disruptions and implementing strategies to recover quickly from extreme weather events that increasingly impact the state's critical electric system infrastructure.

[1] As defined by the major event day methodology detailed in IEEE Std. 1366, IEEE Guide for Electric Power Distribution Reliability Indices.

[2] Tree-related SAIDI refers to the average number of minutes a customer was without power during a given period of time caused by trees in the State of Indiana.

Load & Customer Characteristics

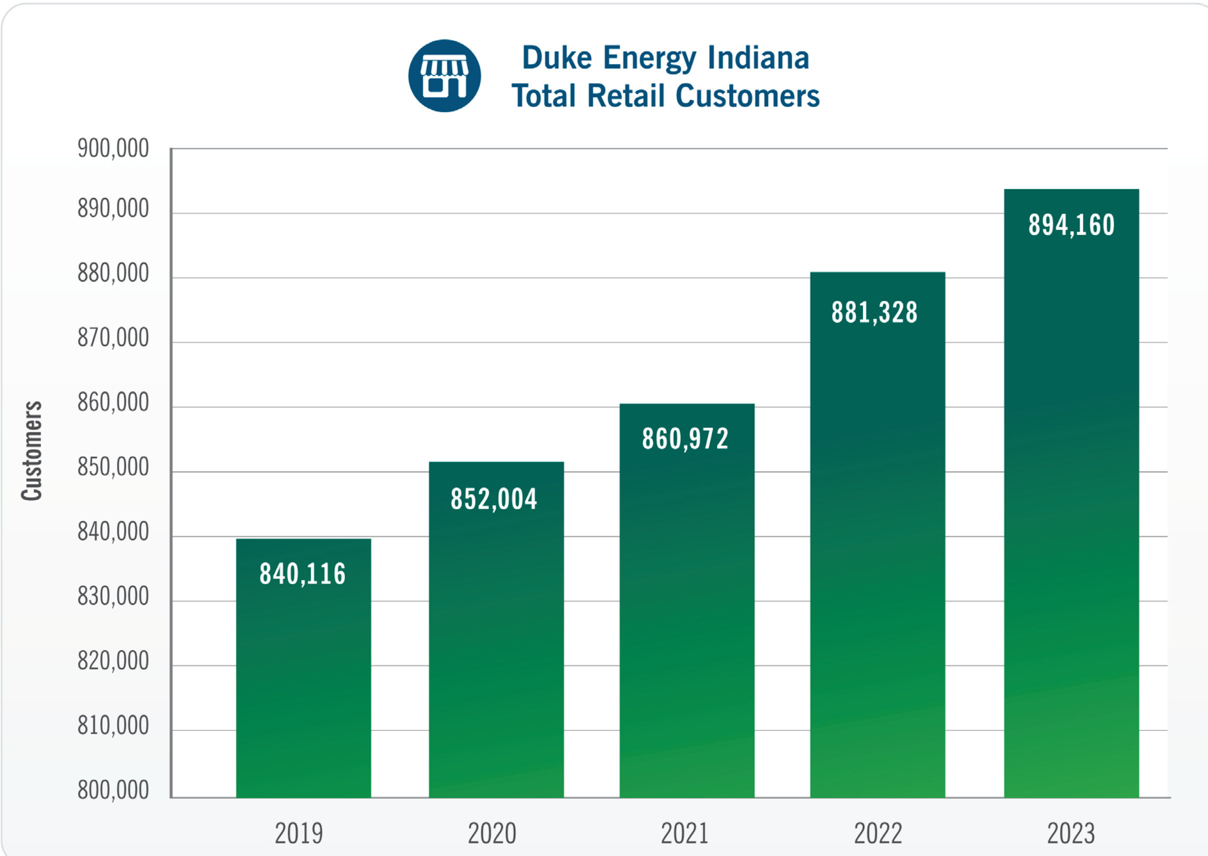
Figure B-7: Customer Segments



For the purposes of resource planning and load forecasting, retail customers are segmented into the following categories: Residential, Commercial, Industrial, Government, and Street Lighting. Additionally, Duke Energy Indiana provides power to wholesale customers, including municipal and cooperative power providers, that in turn supply electric utility service to numerous customers in areas not served by the Company. These customer classes are shown in Figure B-7 above.

The number of retail customers in each category, historical actual and weather-normalized energy sales by customer category, and historical actual and weather-normalized peak demand are displayed in Figures B-8 through B-15 below, sometimes in gigawatt-hours ("GWh"). For additional detail on historical and projected load, see Appendix D (Load Forecast). Appendix D expands on Duke Energy Indiana's forecasted growth, including new economic development load expected in the near-term.

Figure B-8: Duke Energy Indiana Total Retail Customers



Duke Energy Indiana's growth in number of customers is driven by the residential customer class, which has experienced a compound annual growth rate ("CAGR") of 1.5%, and the commercial customer class, which has experienced a CAGR of 0.9% over the periods reflected.

Figure B-9: Duke Energy Indiana Retail Customers by Class

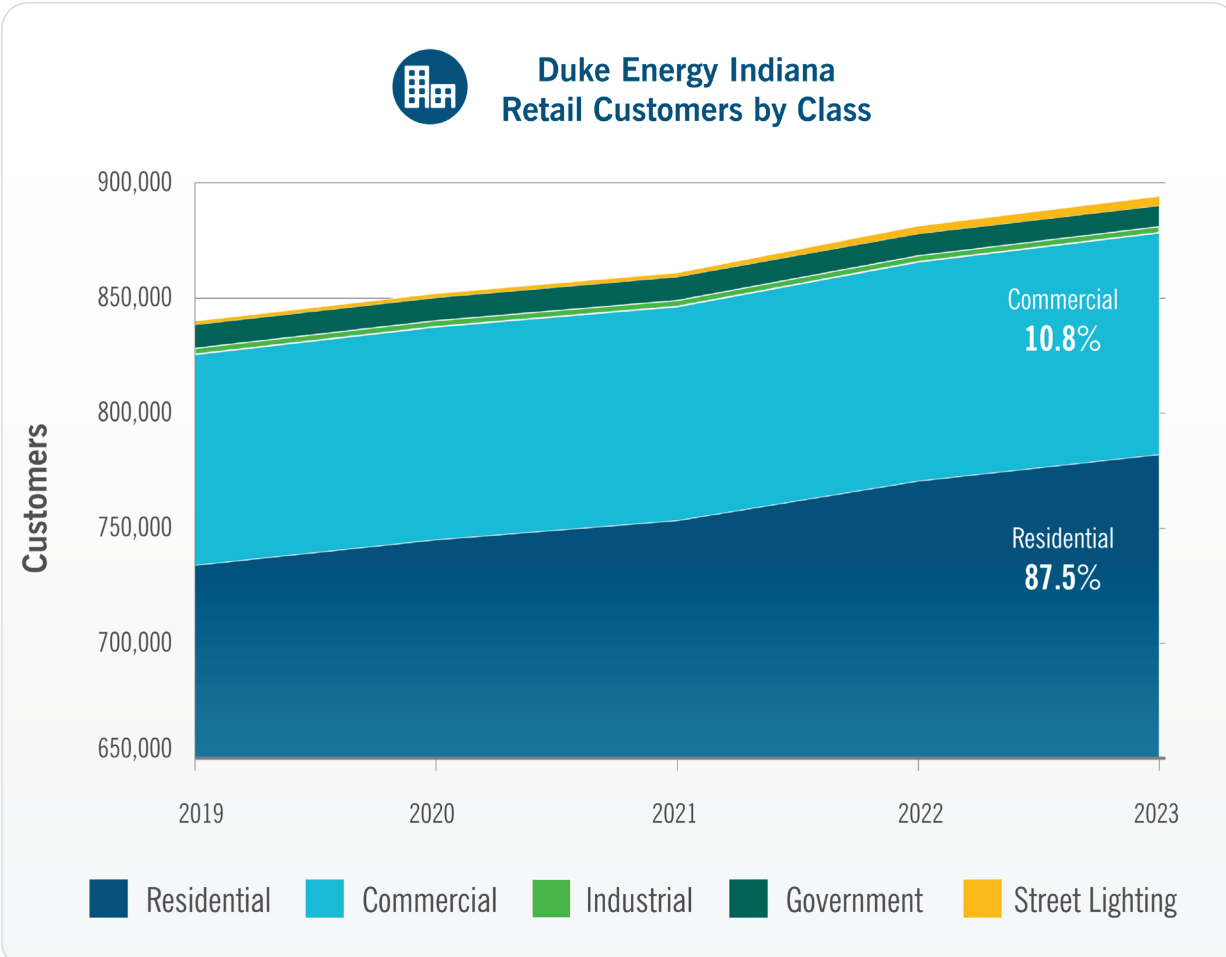


Figure B-10: Historical Retail Sales by Customer Class (Actual)

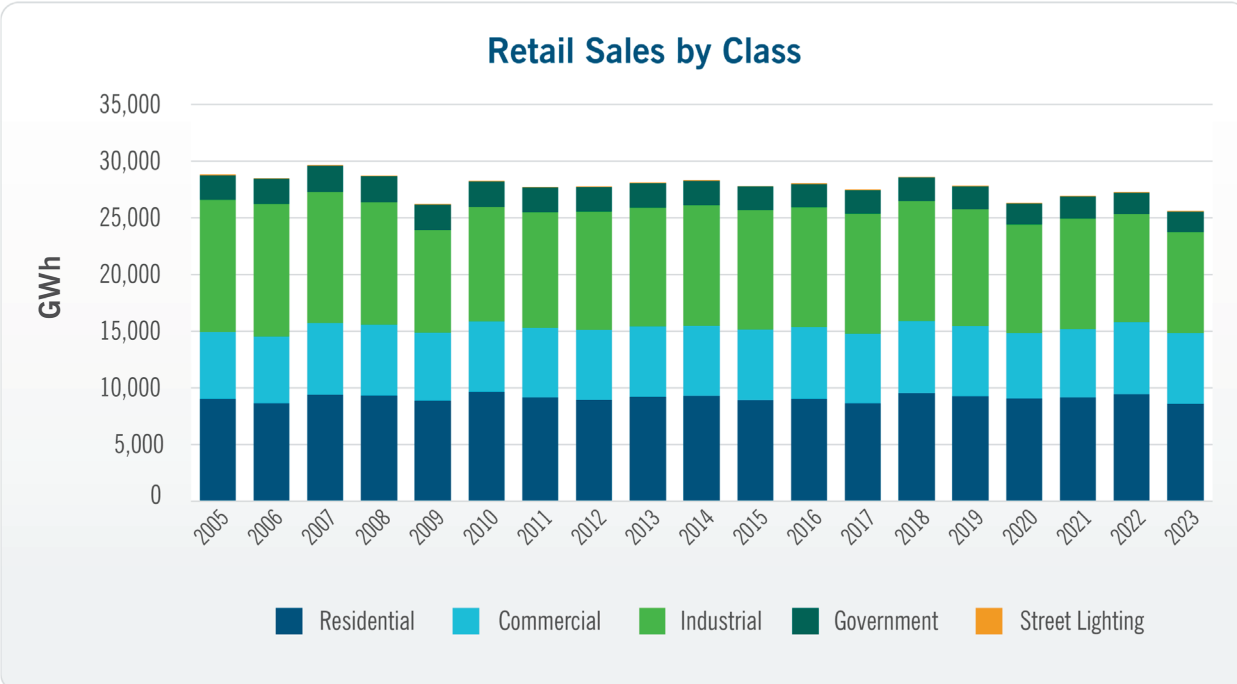


Figure B-11: Historical Total Energy Sales by Customer Class (Actual)

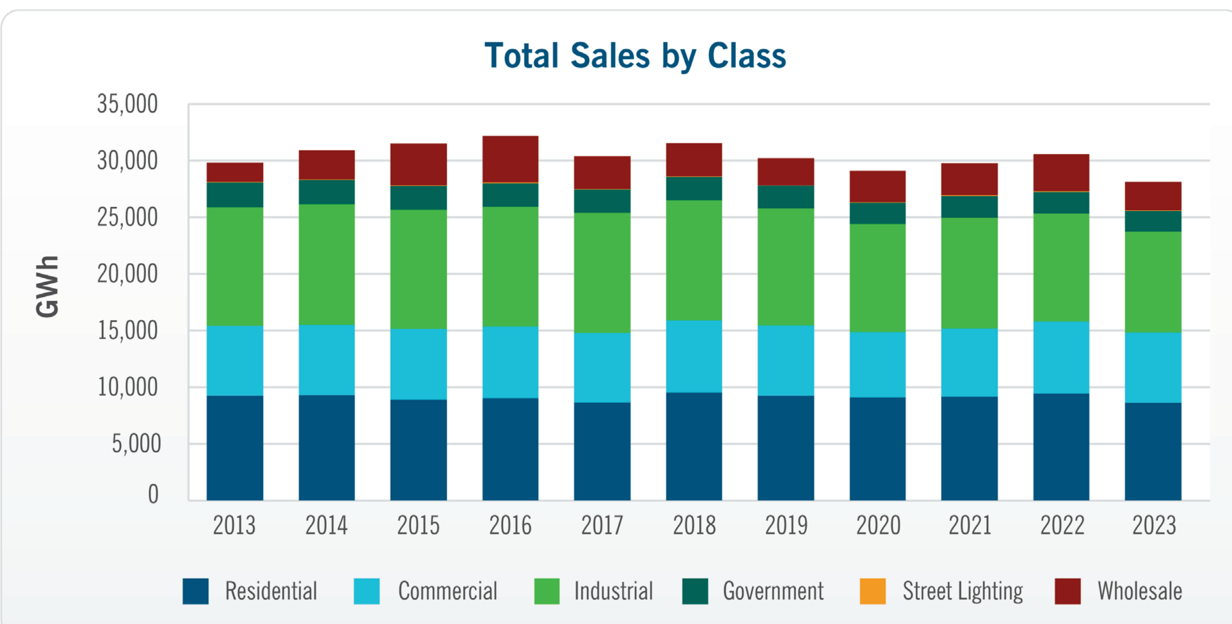


Figure B-12: Historical Weather Normalized Energy Sales by Customer Class

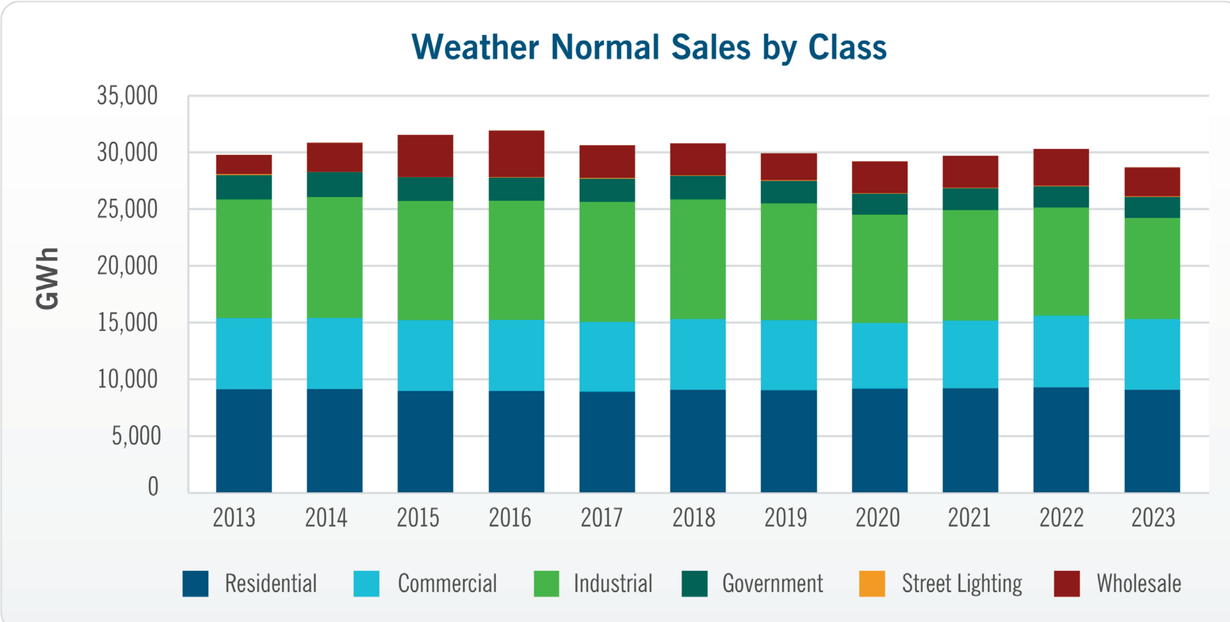


Figure B-13: Historical Total Peak Demand (Retail and Wholesale)

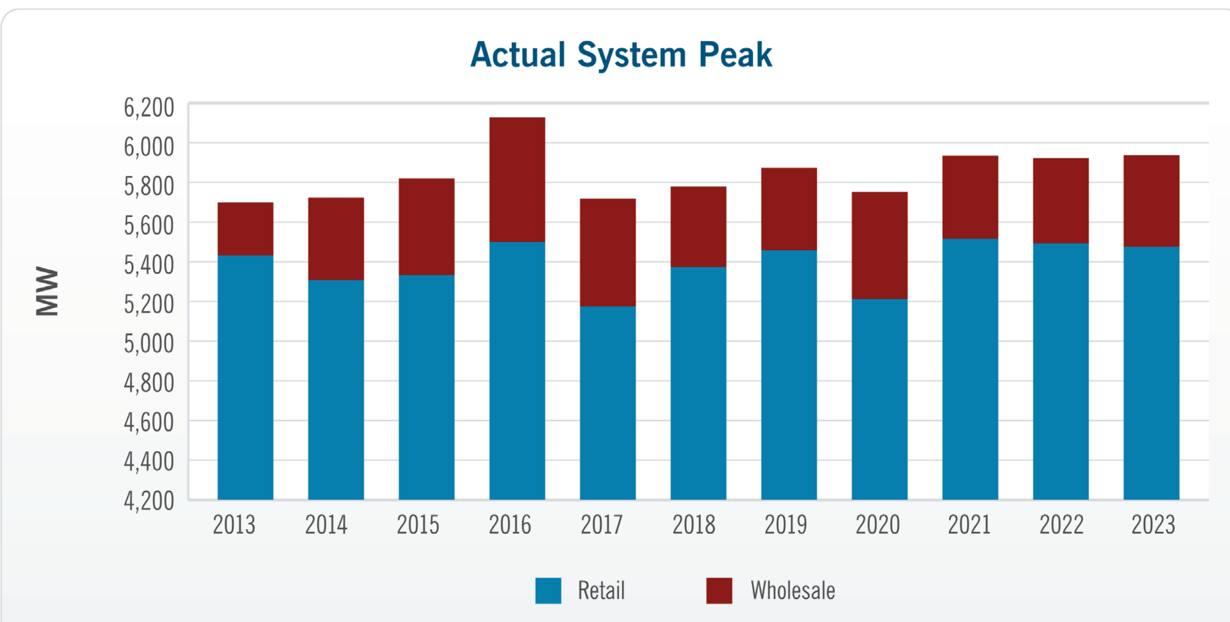


Figure B-14: Historical Peak and Weather Normalized Demand including Wholesale

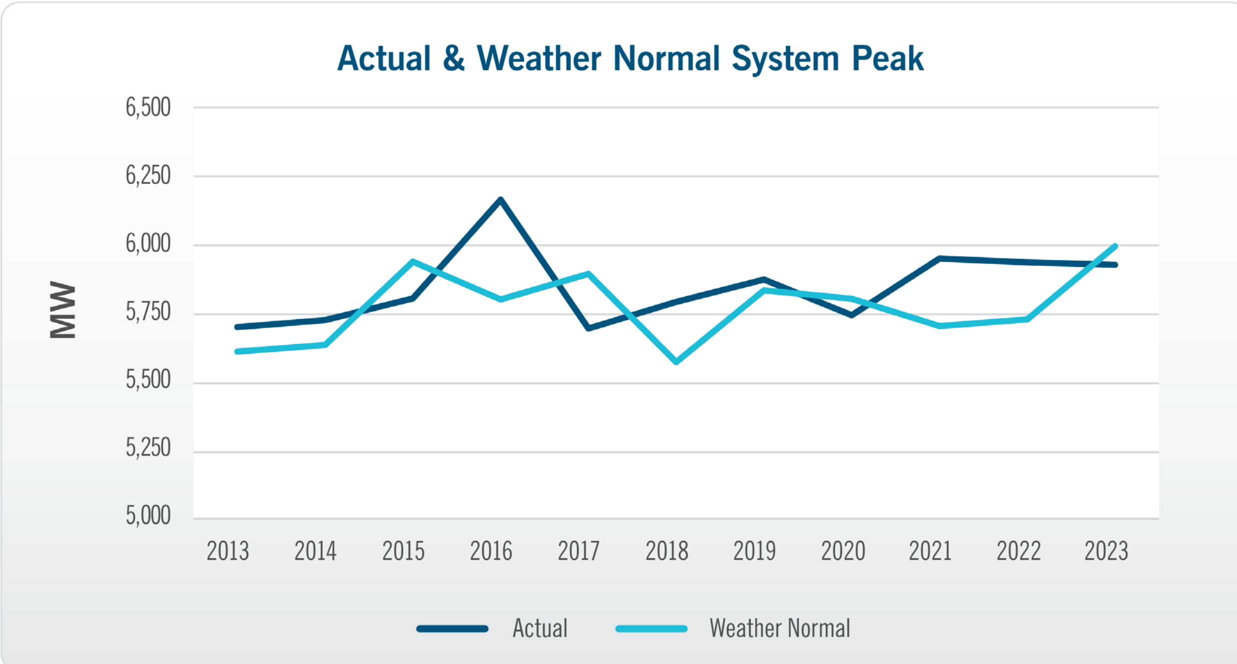
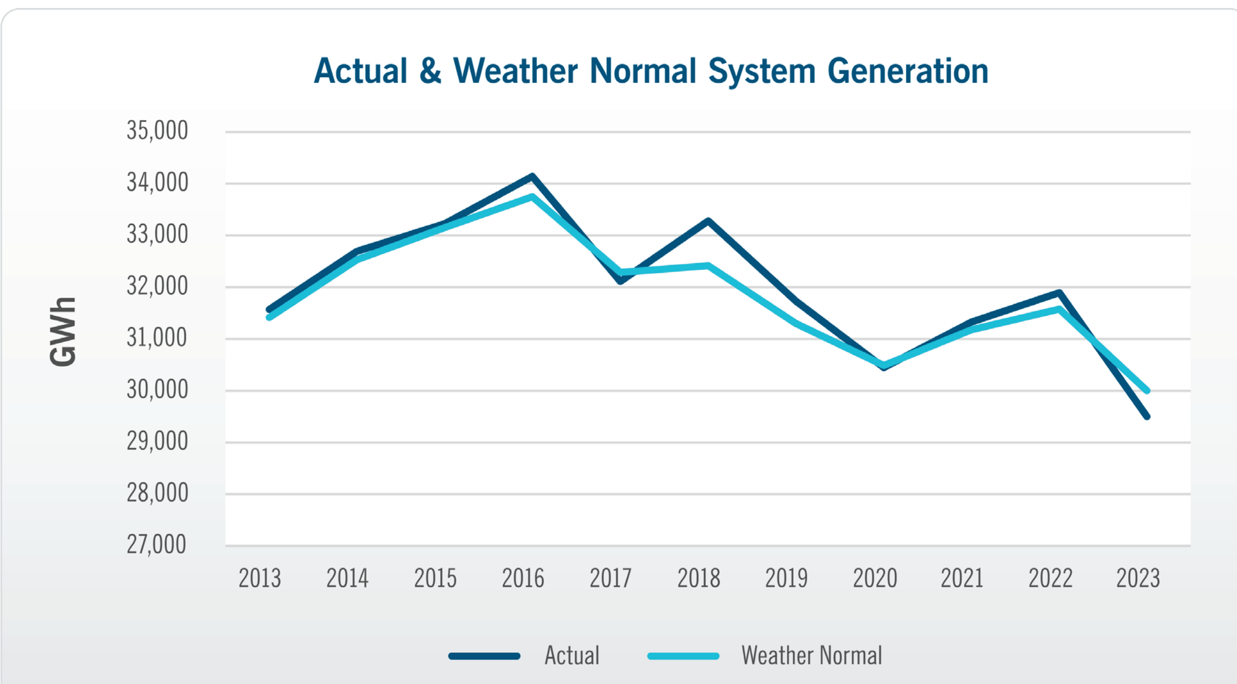


Figure B-15: Historical Actual and Weather Normalized System Generation



Current Demand-Side Resources

Duke Energy Indiana's commitment to energy efficiency ("EE") and demand response ("DR") goes back more than 30 years and remains strong today. The Company offers a variety of programs for all customer classes, which provide incentives for customers to use less energy or shift their usage away from peak times, resulting in savings for all customers. As load continues to grow from economic development and electrification, Duke Energy Indiana customers are at the same time becoming more energy efficient due, in part, to energy efficiency offerings.

In addition to EE and DR, Duke Energy Indiana offers electric vehicle charging programs, time-of-use-rates, behind-the-meter tariffs, and clean energy programs, which provide options for customers to accelerate their own sustainability journey. A variety of policies and other factors – the Inflation Reduction Act, interest rates, Solar for All, MISO's seasonal construct, Load Modifying Resource reforms, and FERC Order 2222 – will contribute to how customers interact with electricity in the coming years. Duke Energy Indiana is following these developments closely and is ready to act for the benefit of customers.

A brief overview of existing demand-side resources and customer programs is included below. A detailed discussion of these resources and programs can be found in Appendix H (Demand-Side Resources & Customer Programs).

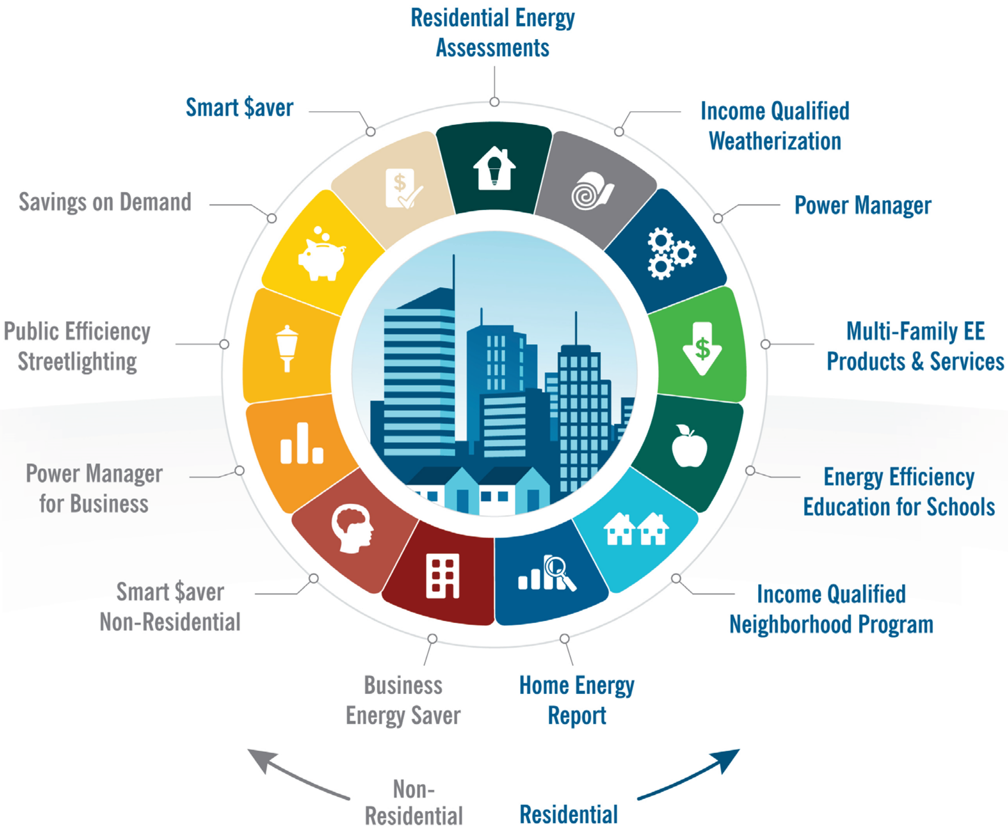
Energy Efficiency & Demand Response

Duke Energy Indiana has a long history of implementing EE and DR programs to support its customers. Duke Energy Indiana's EE and DR programs have been offered since 1991 and are designed to help reduce demand on the Duke Energy Indiana system during times of peak load and reduce energy consumption during peak and off-peak hours. Demand response programs include customer-specific contract options and innovative pricing programs. Over the past 10 years, from 2014 to 2023, Duke Energy Indiana's EE and DR programs have yielded gross energy savings of 2,029,108 MWh.

Current Energy Efficiency & Demand Response Programs

Duke Energy Indiana's current EE and DR program portfolio contains the following set of programs shown in Figure B-16 below. These programs are described in greater detail in Appendix H.

Figure B-16: Duke Energy Indiana Energy Efficiency and Demand Response Programs



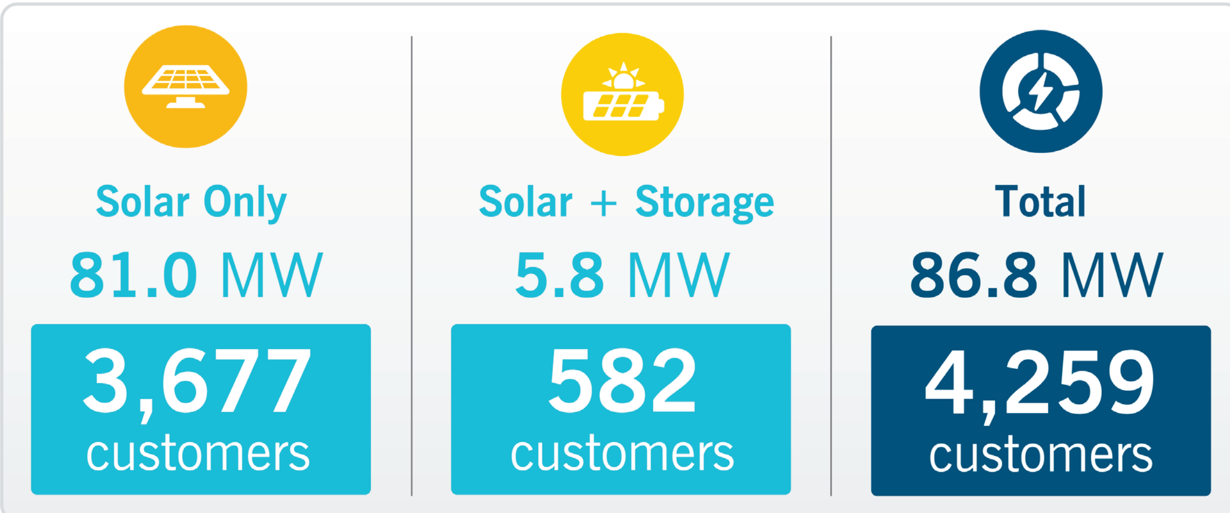
Behind-the-Meter & Clean Energy Customer Programs

Duke Energy Indiana is dedicated to helping its customers achieve their sustainability goals by offering a range of clean energy solutions. One such solution is behind-the-meter generation, a special metering and billing agreement that allows customers to connect their renewable energy-generating systems to the power grid. This setup enables customers to generate their own renewable energy while ensuring a reliable energy supply from the utility during times when their renewable systems are not producing energy. The Company currently offers an Excess Distributed Generation tariff, which specifies the rate at which exports from behind-the-meter resources such as distributed solar resources are valued.

Additionally, Duke Energy Indiana provides voluntary clean energy programs that allow customers to accelerate their sustainability journey beyond installing renewable generation on their property. Options include ways for both residential and business customers to acquire Renewable Energy Certificates, which can be used to match a desired percentage of their energy use with renewable, carbon-free energy. These programs, including the recently approved Green Source Advantage program, are detailed in Appendix H.

Duke Energy Indiana's current capacity from customer-sited behind-the-meter distributed energy resources as of February 2024 is shown in Figure B-17 below.

Figure B-17: Duke Energy Indiana Behind-the-Meter Capacity



Advanced Metering Infrastructure

In 2019, the Company completed its rollout of Advanced Metering Infrastructure ("AMI") across the service territory. The AMI program encompasses smart meters and the associated communications devices that enable automated meter reading, remote connects/disconnects, and quicker outage detection. AMI was a foundational investment to meet the changing needs and expectations of customers. Smart meters are a key component of a modern grid, as they have two-way communication capabilities and can transmit energy usage information back to Duke Energy more frequently than walk-by or drive-by meters. This allows customers to see much more detailed energy usage and billing information. Smart meters also help the utility to more quickly identify power outages and resolve other service requests and problems, typically without needing to visit a home or business.

AMI offers many advantages to the customer, including access to new service and billing options like Pick Your Due Date and Usage Alerts, ability to see detailed usage data daily, making it easier to use energy more efficiently and lower bills, and the option to stop/start service remotely without an appointment. AMI also allows for improved response times and speeds outage repairs. Additionally, AMI plays a crucial role in enabling time-of-use ("TOU") rates by providing detailed, real-time data on electricity consumption. This technology and the insights provided by AMI data further support the Company's recently proposed TOU rates for multiple customer segments by allowing more refined measurement of nearly all of its customers' service.

Duke Energy Indiana is working to improve the use of AMI and smart grid technologies. The load research team has transitioned from a sample design process using data from less than 1% of customers to a near-total population approach using over 99% of customer data now that 99.6% of retail customers have AMI meters. The AMI data is pulled into a large data platform at a near-real-time cadence and converted to support load research ratios and demand statistics both programmatically and by a dedicated analyst. This has increased accuracy from a 90/10 statistical confidence interval to 99%+ for load shapes and statistics, which are used as inputs to load forecasts and modeling of new products, services, and programs. Further, AMI capabilities have increased situational awareness by customer groups and opened the door for other emerging use cases.

History of Operational Excellence

At every step of generating, transmitting, and distributing energy, Duke Energy Indiana has a relentless commitment to performing tasks safely, reliably, and efficiently, which empowers us to exceed customer expectations. The Company's strong reliability, safety, and customer satisfaction performance results are a product of this commitment.

Safety is a core value for Duke Energy Indiana, and the Company is committed to employee, contractor, and public health and safety. Duke Energy Indiana strives to be an industry leader in safety and seeks continual improvement through commitment, ownership and engagement. Duke Energy continues to be among the industry leaders in employee safety results. Duke Energy Indiana monitors safety results using a variety of reportable metrics including two metrics that are based on industry standard measures.

- The Total Incident Case Rate ("TICR") represents the number of total Company employee injuries or illnesses, per 200,000 hours worked, that meet the Occupational Safety and Health Administration ("OSHA") definition of recordability. This metric is also known as the OSHA recordable incident rate.
- The Days Away, Restricted, or Transferred ("DART") rate represents the number of total Company employee injuries or illnesses, per 200,000 hours worked, that result in death, days away from work, restricted work, or job transfer, and prevent employees from performing typical duties.

The Company's 2023 employee safety results are shown in Figure B-18 below.

Figure B-18: 2023 Duke Energy Indiana Employee Safety Results

Commitment to Indiana’s Energy Future

Duke Energy Indiana remains steadfast in its commitment to providing reliable, affordable, and sustainable energy to its customers across a diverse service territory. As the energy landscape continues to evolve, the Company is taking reasonable and prudent steps to transition to cleaner energy sources while maintaining a focus on reliability, resiliency, stability, and affordability. Through strategic investments in generation, transmission, and distribution systems, as well as its continued focus on customer-centric demand-side programs, Duke Energy Indiana is well-positioned to meet the growing energy needs of Indiana's communities. Looking ahead, the Company will continue to play a vital role in powering the state’s economic development and supporting its customers on their journey toward a sustainable energy future.

Appendix C: Quantitative Analysis

Highlights

- The modeling and quantitative analysis performed to develop the generation strategies, strategy variations, and sensitivity analysis are supported by a robust process to develop inputs and leverage sophisticated capacity expansion, production cost, and reliability models.

- This quantitative analysis supports selection of the Blend 2 Generation Strategy as the Preferred Portfolio and guides the Short-Term Action Plan including the prudent steps to support a balanced transition and growth in the context of a changing energy landscape.

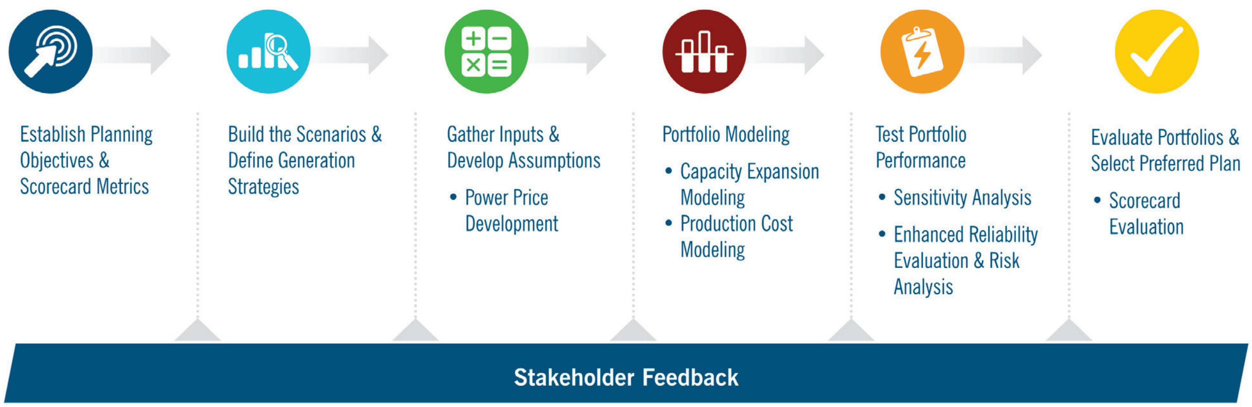
- This Appendix provides additional insights into the development of inputs and modeling setup, as well as the development and verification of portfolios, and describes the detailed portfolio performance analysis utilized to assess the opportunities, trade-offs, and risks between resource selection that impact affordability, reliability, and emissions reductions.

This Appendix discusses the quantitative analysis performed by Duke Energy Indiana (the "Company") to develop the 2024 Integrated Resource Plan ("IRP" or the "Plan"). Indiana's Five Pillars of energy policy, which are reliability, affordability, resiliency, stability and environmental sustainability, shaped the development of the IRP. In addition, the Company carefully assessed risks and uncertainty, and this IRP includes prudent risk mitigants and the flexibility to adapt to changing conditions.

The IRP relies on long-term planning analysis that includes a variety of forecasts, assumptions, and other quantitative inputs that capture information about the current system, future resources, and future market and regulatory conditions. The Company developed base case forecasts and assumptions, as well as alternates that it used to quantify risks and opportunities, and to assess the sensitivity of results to forecast variability. The analytical process involves several steps, including capacity expansion and production cost modeling, stochastic risk analysis, and further analysis of model outputs to draw insights and develop certain metrics such as the present value of revenue requirements ("PVRR") and average retail customer bill impacts. This Appendix provides extensive detail on the Company's modeling inputs and assumptions, analytical approach and methodology, and observations and conclusions from the quantitative analysis performed for the 2024 IRP.

Analytical Process

Figure C-1: 2024 IRP Analytical Process



The Company's analytical process, summarized in Figure C-1 above, begins with specification of the resource planning objectives. The planning objectives for the 2024 IRP, which are founded in Indiana's Five Pillars, are presented in Chapter 2 (Methodology).

From there, the Company develops a set of different potential futures called planning scenarios, or "worldviews," and identifies several potential generation strategies that it could choose to pursue. Each planning scenario is a plausible potential future for the market and regulatory environments in which the Company operates. Planning scenarios are defined by factors external to the Company and beyond its direct control, and each planning scenario is created with a discrete set of forecasts and specific assumptions that are plausible, internally consistent, and that can be specified as quantitative inputs to IRP analytics. The Company develops a Reference Scenario, which is the most likely future, and plausible alternate scenarios that explore different outcomes in key areas of uncertainty that could fundamentally alter the performance of the Company's resource portfolio with respect to one or more planning objectives. Together, the planning scenarios describe the range of plausible futures for the factors that most significantly influence the Company's ability to appropriately balance the planning objectives.

While planning scenarios describe the world external to the Company and outside of its direct control, the generation strategies and associated candidate resource portfolios are defined by decisions the Company could make with respect to existing and potential future resources. Each strategy may have its own strengths and weaknesses, the relative importance of which may vary across the different planning scenarios. The evaluation of these strengths and weaknesses and the ultimate identification of the Preferred Portfolio is the primary purpose of the IRP analysis.

Once the planning scenarios and generation strategies are established, the Company assembles the inputs to the quantitative analytics. This process brings together information and insights from the Company's own subject matter experts, as well as Indiana IRP stakeholders and third-party experts. Candidate resource portfolios are developed using the capacity expansion model, and the hourly dispatch of these portfolios is simulated using the production cost model. Sensitivity analysis is conducted to evaluate potential changes to both resource selection and portfolio operating costs in response to variation in key inputs to assess the robustness of the candidate portfolios with respect to uncertainty and to identify potential areas in which it will be important to monitor changing conditions and be prepared to adjust course. The Company also conducts stochastic analysis to assess relative cost and reliability risks across candidate portfolios to ensure that it identifies a Preferred Portfolio that appropriately mitigates these risks. Finally, the Company evaluates the complete set of analytical results and identifies a Preferred Portfolio that appropriately balances the planning objectives. Each step in the analytical process is described in more detail throughout this Appendix.

Modeling Software & Development of Modeling Assumptions

The Company takes a rigorous approach to developing the hundreds of inputs and assumptions required for quantitative IRP analytics and uses sophisticated modeling software to develop and evaluate candidate resource portfolios from the thousands of possible combinations of resource changes over the 20-year planning period. The modeling assumptions presented in this Appendix reflect the best information available at the time the 2024 IRP was developed. Actual costs, operating characteristics, and deployment timelines will change over time depending on the pace of technology development, supply chain constraints and availability of new resources, and policy developments as the country and global energy industry continue to transition.

Modeling Software

The core of the IRP analytical toolkit consists of two types of models, a capacity expansion model and a production cost model. Duke Energy Indiana used EnCompass modeling software version 7.1.4, licensed through Yes Energy (formerly known as Anchor Power Solutions), to perform both capacity expansion modeling and production cost modeling, which are contained within the EnCompass software as separate modules.

Capacity Expansion Modeling

Capacity expansion models are first and foremost screening models. These models are used to assess a broad range of potential resource combinations to develop candidate portfolios that minimize the cost of the system while adhering to planning parameters that represent real-world operations and resource availability. They do this using a wide range of inputs, including detailed load projections, costs and characteristics for new and existing resources, expected new resource availability, generation profiles, fuel and operations costs, and various detailed system operating requirements. To solve a complex analytical problem of such breadth in a reasonable amount of time, the capacity expansion model necessarily uses a simplified version of reality, dividing the 20-year planning period into representative time blocks to assess the performance of portfolios more quickly against a simplified representation of the system load requirement. Iterations of different mixes of resources over time are applied to these simplified system representations to determine a mix of resources that result in the lowest cost to the system while also meeting energy and capacity requirements of the system. The output of each capacity expansion model run is a preliminary resource portfolio to meet customers' energy and capacity needs over time.

The breadth of the computational problem that the capacity expansion model is used to solve means that it cannot simulate system performance in sufficient depth for the IRP. This depth is achieved using production cost models described below.

Production Cost Modeling

Production cost models differ from capacity expansion models in that they do not solve for portfolio composition. Instead, a production cost model provides a detailed simulation of system operations for a specific resource portfolio developed using the capacity expansion model. Additionally, the production cost model uses detailed hourly simulations of resource commitment and dispatch to meet system load requirements through economical operation of the system. In contrast to capacity expansion models, production cost models maintain full chronology and load requirements in all hours to simulate hourly system operation. The granularity of this analysis appropriately captures a resource portfolio's ability to reliably serve customer load and the cost/benefits to the system, while accounting for resources with specified generation profiles. These profiles may vary hourly, daily, monthly, or seasonally. Like the capacity expansion model, the production cost model in the EnCompass software package is a deterministic model, relying on fixed forecasts for load, fuel prices, and other inputs. This deterministic approach is necessary for the production cost model to be able to evaluate every hour of the 20-year planning period in a reasonable amount of time. The Company uses stochastic modeling tools to simulate thousands of variations on expected future conditions for selected study years. These tools are described further below.

EnCompass Modeling Enhancements

To improve the transparency of the modeling process, the Company relied on the EnCompass model's internal capability to calculate levelized economic carrying costs for new resources rather than using the proprietary cost-levelization model used in previous planning cycles. The inputs required for this calculation include Company assumptions such as capital structure and debt and equity rates, as well as assumptions specific to each resource type, including construction period, capital cost, asset useful life, tax life, and other parameters. Performing cost calculations using the internal capabilities of the EnCompass model also reduces data transfer between analytical tools, streamlining the analytical process.

Additionally, the Company integrated dynamic dispatch of batteries paired with solar resources. Previously, a fixed profile was input into the model to simulate the expected behavior of a battery paired with a solar system. Implementing dynamic dispatch allows the model to optimize the usage of batteries paired with renewables as system needs change over time. The Company also allowed grid charging of paired storage resources in this IRP, further enhancing the model's ability to capture the flexibility benefits of paired storage resources. Optimizing charging and discharging of energy storage is one of the most complicated tasks for IRP models, an issue that is exacerbated by requiring the model to evaluate and choose among standalone and paired storage resource options. The Company will continue to evaluate whether including a generic paired energy storage resource as a separate option in IRP analysis is warranted and may revert to using only standalone resources for generic modeling purposes to reduce analytical complexity in future IRPs.

The Company also refined the model scenario settings in this planning cycle, including updates to the capacity expansion model's typical day structure to help balance the evaluation of resources while maintaining a single optimization over the entire study period. As the number of resource options grows and analytical complexity increases, the Company must continue to be cognizant of the impacts to model run time. Including complex operations, resource selection modeling, and cost information, additional capabilities of the model further increase the model problem size and, as a result, may lead to unreasonable model run times. As mentioned above, the Company has deployed several modeling advancements in this planning cycle. Both now and in the future, the trade-offs between the sheer number of selectable resource types, operational options and requirements, and other modeling parameters must be balanced to allow for efficient, meaningful, and differentiating analyses.

Stochastic Analytics Tools for Risk Assessment

In this IRP, the Company has leveraged two additional models, SERVM[1] and PowerSIMM, to further explore the operational characteristics of the generation profiles produced in the EnCompass model. Both of these production cost-type models are considered "stochastic" due to their ability to simulate multiple, path-dependent scenarios of power system dispatch. Stochastic modeling can reveal uncertainties and risks that single scenario, deterministic models may not show. These stochastic tools simulate hundreds (PowerSIMM) to thousands (SERVM) of years of hourly dispatch to quantify operational, economic, and reliability uncertainties. Their usage and underlying modeling assumptions are discussed in more detail later in this Appendix.

Planning Horizon

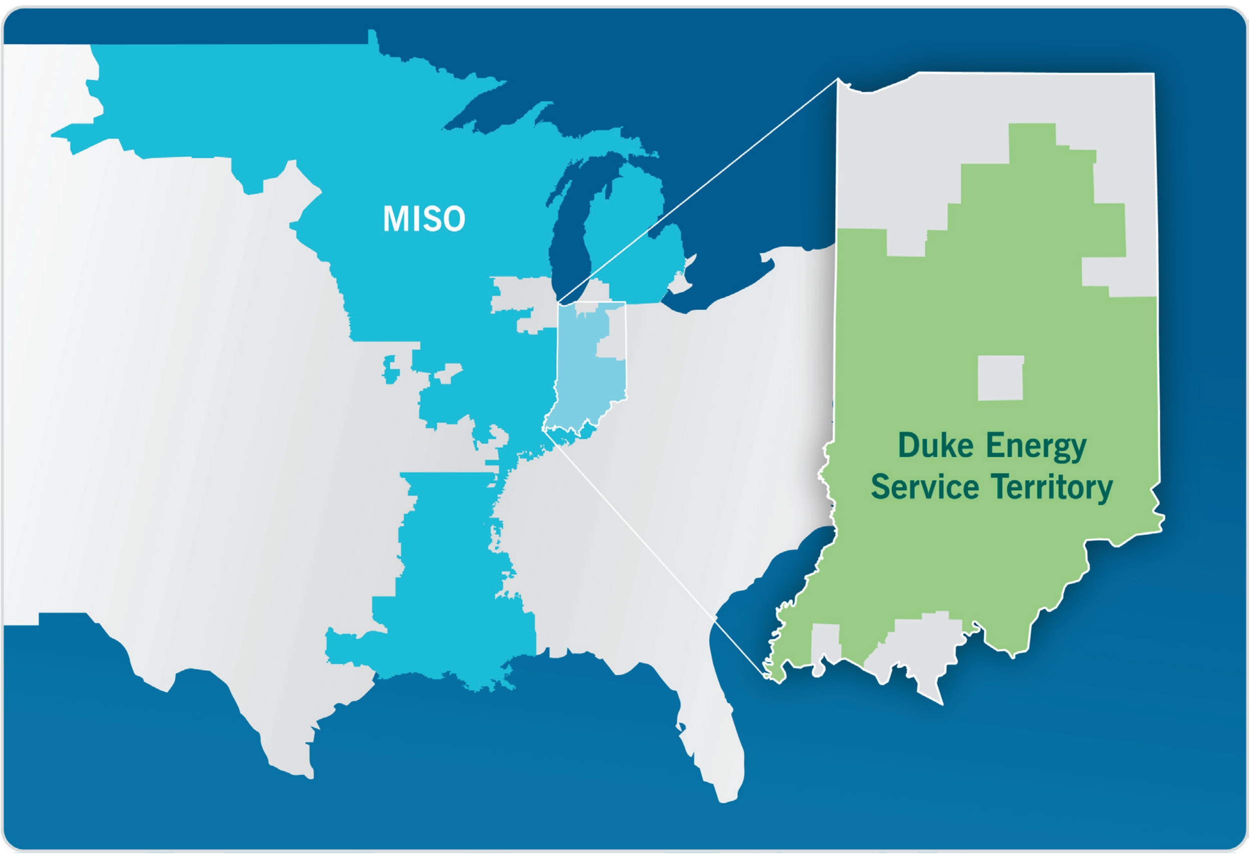
The Company's 2024 IRP is a 20-year plan, covering the years 2025 through 2044. This long-term view provides early indication of new resource needs, allowing time to check and adjust the plan in response to changing conditions, and is essential in an industry in which new resources can take many years to bring to fruition, from need identification to project completion. The 20-year planning window allows for the development of a reasonable and prudent plan to safely, reliably, and cost-effectively serve customers' future needs, providing adequate time to check and adjust as necessary.

[1] The Strategic Energy & Risk Valuation Model ("SERVM") is a state-of-the-art reliability and hourly production cost simulation tool managed by Astrapé Consulting, which provides consulting services and/or licenses the model to its users.

Modeling the Duke Energy Indiana System

For capacity expansion and production cost modeling purposes, Duke Energy Indiana treats its system as a single entity operating in the state of Indiana as part of the Midcontinent Independent System Operator ("MISO"). The Company models its own load and resources, incorporating MISO market participation in the analytics as economic energy purchases and sales. A map of Duke Energy Indiana within MISO is shown in Figure C-2 below.

Figure C-2: Duke Energy Indiana Service Territory Within the MISO Footprint



As part of the IRP process, the Company develops long-term fundamental power price projections for each of the planning scenarios and also for certain sensitivity analyses. The Horizon Energy National Database, which provides the existing resource mix for the entire Eastern Interconnection including MISO, serves as the basis for the development of these power prices. The Company makes adjustments to fuel price forecasts, carbon tax assumptions, technology assumptions, resource availability assumptions, and effective load carrying capability ("ELCC") to align with each worldview and sensitivity analysis case as appropriate.

The Company runs both capacity expansion and production cost models to develop power price projections; however, due to extensive Eastern Interconnect system inputs, single-year segmentation is implemented in the capacity expansion runs to minimize problem size and ensure reasonable model run times. Results of the national database runs are discussed in more detail later in this Appendix.

Reliability Requirements

Ensuring reliability is a priority in resource planning. Key reliability inputs to the analysis include planning reserve margins, ELCC values, and operating reserve requirements. These inputs are foundational resource planning components that ensure the Company will be able to maintain or improve upon the adequacy and reliability of the grid.

MISO provides both a Planning Reserve Margin (“PRM”) for the system and an ELCC for each resource type. The PRM is a function of expected peak load for a given season, and the ELCC rating indicates the firm capacity a resource can provide at times of peak demand.

Currently, MISO determines PRMs by season and assigns seasonal firm capacity values for each resource type using the Seasonal Accredited Capacity (“SAC”) construct. In early 2024, MISO filed proposed changes with the Federal Energy Regulatory Commission (“FERC”) to adopt a two-step resource accreditation method called the Direct Loss of Load (“DLOL”)-based capacity accreditation methodology starting in the 2028/2029 planning year. Although MISO is still awaiting FERC approval of the changes, the need for further refinement of the accreditation methodology is clear for MISO to meet its reliability imperative. For this reason, it is reasonable to expect that future resource accreditation will more closely resemble the DLOL method than the current SAC construct, making it prudent to use the DLOL approach for long-term planning. In the modeling for the 2024 IRP, the Company uses the SAC-based PRM and resource accreditation for 2025-2027 and moves to DLOL starting in 2028.

Planning Reserve Margin

MISO provides both regional transmission organization (“RTO”)-level PRMs and zonal coincidence factors to account for zonal contribution to peak. For DLOL, MISO provided initial PRM estimates under the new construct, which the Company used to develop the PRM for the 2024 IRP analytics. Under the DLOL construct, the PRM for certain seasons is negative after applying the zonal coincidence factors provided by MISO.

As discussed in Chapter 3 (Key Assumptions), Duke Energy Indiana models a non-coincident peak load forecast in the 2024 IRP. The resulting reserve margin values used for each season in each construct, shown in Table C-1 below, incorporate both the coincident PRM and the seasonal peak coincidence factors for MISO Local Resource Zone (“LRZ”) 6 (Duke Energy Indiana is in LRZ 6). A positive PRM indicates that the total capacity requirement exceeds forecasted peak load, and a negative PRM indicates that the requirement is less than 100% of the expected peak.

Table C-1: Non-Coincident Planning Reserve Margins Used in 2024 IRP Modeling

Accreditation Methodology	Non-Coincident Planning Reserve Margin			
	Winter (Dec-Feb)	Spring (Mar-May)	Summer (Jun-Aug)	Fall (Sept-Nov)
SAC	16.8%	21.8%	5.6%	9.3%
DLOL	-5.8%	-2.7%	1.0%	4.5%

Effective Load Carrying Capability

The Company used MISO class average seasonal accreditation values as the starting point for each resource.[2] For thermal and storage units, the initial value does not change over time since these are dispatchable and available to serve load at any time when not in planned maintenance or forced outage. However, because solar and wind resources cannot be called upon at will, and because output from these resources is highly correlated across large regions, the capacity value of these resources erodes as their share of the market increases. In other words, reliability risk shifts away from periods when solar and wind output are plentiful and into periods when it is not, decreasing the capacity value of solar and wind and increasing the capacity value of resources that can be called upon at times when solar and wind are not available. For example, winter peak loads for Duke Energy Indiana occur in the early morning and late evening when solar output is low, while peak loads in the summer occur across the afternoon and early evening, which is more coincident with solar output. As a result, the capacity value of solar in the summer season is much greater than it is in the winter.

The ELCC of a resource can be thought of as the reliability contribution of that resource when it is added to an existing portfolio. Several factors can contribute to a resource's ELCC, including its generation profile (if determined by wind speeds or solar irradiance) or the amount of energy a resource can store. ELCC may also vary based on loading levels of other resources on the system.

The Company retained 1898 & Co. ("1898") to develop ELCC curves for use in the 2024 IRP analytics. Using the MISO capacity expansion plan that the Company developed when it prepared its fundamental power price forecast, along with data provided in MISO stakeholder meetings, 1898 developed ELCC curves for solar and wind resources. These curves were applied to wind and solar resources in the "local" (Duke Energy Indiana system) model runs to capture expected accreditation changes for those resources over time as the MISO capacity mix evolves. Winter and summer resource accreditation percentages for each resource type, based on MISO's ELCC curves and Schedule 53, are provided below in Table C-2 and Table C-3, respectively.

[2] MISO Planning Year 2023/2024 Schedule 53 Class Averages (for thermal units) was released March 28, 2023. MISO 23/24 PY PRM and Local Reliability Requirements LOLEWG (for starting solar/wind ELCC values) was released October 3, 2022.

Table C-2: Annual Winter Resource Accreditation Percentages by Resource Type (%)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	74.0	74.0	74.0	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4	61.4
CC	97.3	97.3	97.3	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0	74.0
CT	95.0	95.0	95.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
Solar	13.4	12.3	12.3	2.0	2.0	2.0	1.9	1.8	1.6	1.4	1.2	1.1	1.1	1.3	1.3	1.4	1.6	1.6	1.8	2.0
Battery	80.0	80.0	80.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0	91.0
Wind	19.2	18.7	18.5	15.3	15.2	15.1	14.9	14.8	14.6	14.4	14.2	14.2	14.2	14.2	14.2	14.0	13.9	13.8	13.7	13.6
Nuclear	97.0	97.0	97.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0

Note: Combined cycle (“CC”); combustion turbine (“CT”)

Table C-3: Annual Summer Resource Accreditation Percentages by Resource Type (%)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	76.3	76.3	76.3	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1	72.1
CC	93.9	93.9	93.9	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
CT	96.7	96.7	96.7	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0	88.0
Solar	24.2	22.2	22.2	36.0	36.0	36.0	33.7	28.0	22.6	17.2	11.7	6.1	3.8	3.4	3.3	3.2	2.9	2.7	2.4	2.0
Battery	80.0	80.0	80.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0	94.0
Wind	15.1	14.6	14.5	11.7	11.8	11.9	11.5	10.9	10.0	9.2	8.6	8.5	8.4	8.3	8.2	7.6	7.2	6.6	6.3	5.6
Nuclear	97.0	97.0	97.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0

Electric Load Forecast

The load forecast is a critical factor in utility system planning. At its core, integrated resource planning is about aligning the resource portfolio with projected customer needs. The load forecast can influence the quantity of resources added over time, which types of resources are added, and the load can have a significant impact on portfolio performance with respect to planning objectives. Below are brief descriptions of the basic components of the 2024 IRP load forecast and the assumptions made for base planning and sensitivity analysis for each component. More discussion on Load Forecasting is included in Appendix D (Load Forecast).

Base Economic Forecast

The economic forecasts for Duke Energy Indiana were obtained from Moody’s Analytics, a nationally recognized economic forecasting firm. Moody’s prepares a series of key regional economic indicators, including history and projections of employment, income, wages, industrial production, inflation, prices, and population. This information is used to develop the customer growth and energy volumes to generate the base load forecast. The Company also developed economic high and low scenarios to assess impacts of increased or decreased economic indicators on the load forecast over the long term.

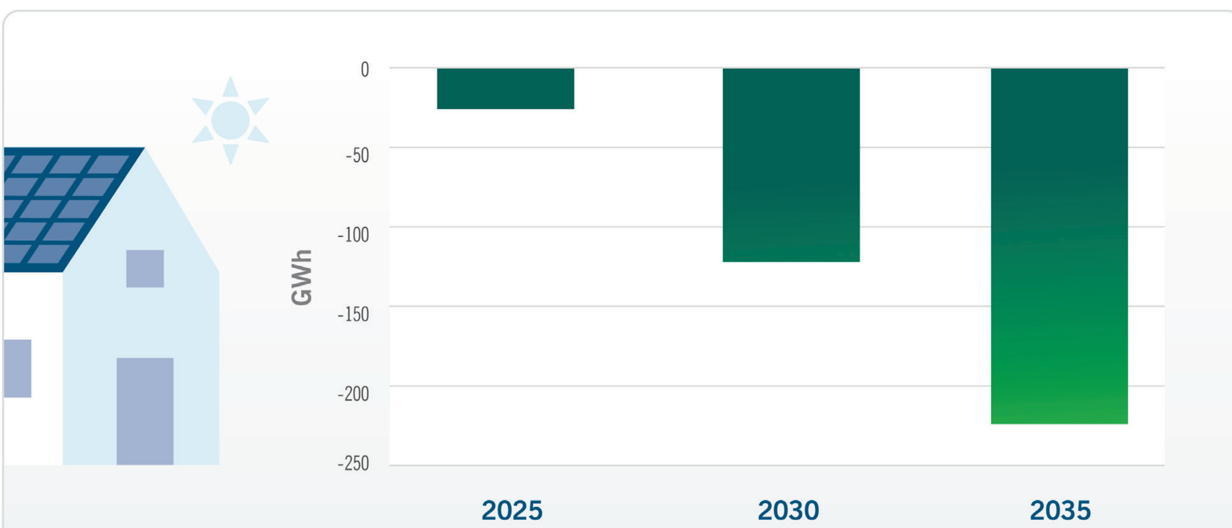
Load Modifiers

As described in Chapter 3, behind-the-meter ("BTM") generation and electric vehicles ("EV") are expected to significantly impact Duke Energy Indiana's net retail load over the 20-year planning period. New utility energy efficiency ("UEE") programs are included as a selectable resource in modeling and are not reflected in the load forecast. However, contributions from existing UEE programs are removed from the load forecast to avoid double counting as those programs reach end of life and are overtaken by naturally occurring efficiency trends.

Behind-the-Meter Generation

Base BTM solar growth reflects currently approved Excess Distributed Generation rates in Indiana. BTM solar reduces customer load by generating energy for self-consumption with excess energy put onto the grid. The forecast reflects the net impact to the load forecast as an adjustment in reduction of energy for the supply-side resources are required to meet. The penetration levels and growth rates for BTM solar vary by worldview. Figure C-3 below shows the impact of the BTM solar generation base forecast on net energy projections for in 2025, 2030, and 2035 expressed in gigawatt-hours ("GWh").

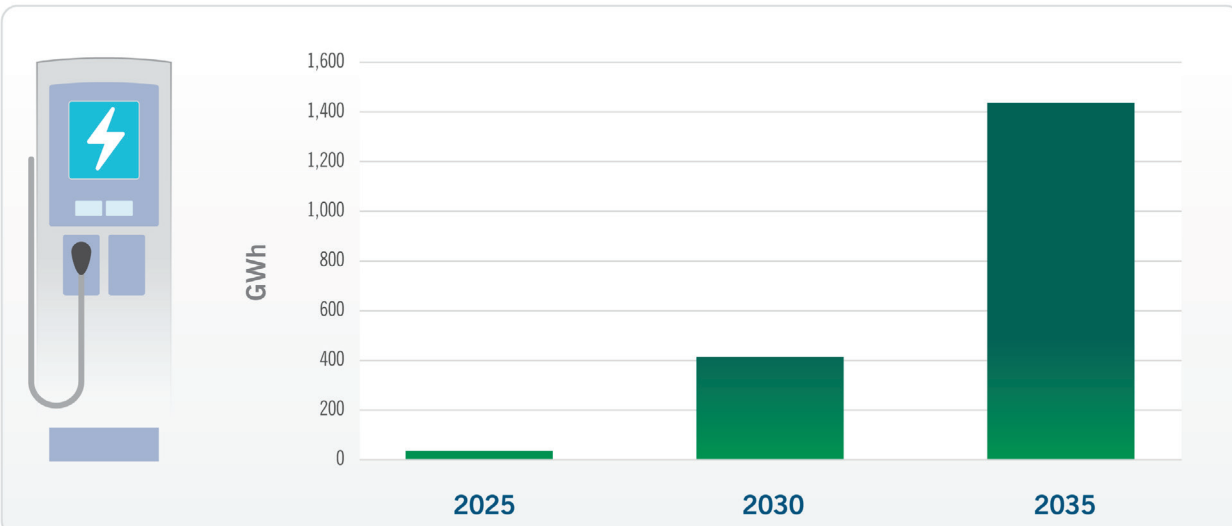
Figure C-3: Behind-the-Meter Generation Load Projection in 2025, 2030 and 2035 (GWh)



Electric Vehicles

The base electric vehicle load forecast was developed using the Guidehouse Vehicle Analytics and Simulation Tool, which uses multiple inputs, including forecasted vehicle registrations, customer acceptance and utilization, efficiency characteristics, and projected vehicle miles traveled. More information on the long-term EV forecast and how EVs impact the growth in system demands, as well as details on various load management and pilot programs, can be found in Appendix D and Appendix H (Demand-Side Resources & Customer Programs). Figure C-4 below shows the impact of the base EV forecast on net energy load in 2025, 2030, and 2035.

Figure C-4: Electric Vehicle Energy Load Projection in 2025, 2030 and 2035 (GWh)



Utility Energy Efficiency Historic Roll-Off

The efficiency savings associated with existing UEE programs are deducted from the load forecast, while potential future energy efficiency programs are included as selectable options in capacity expansion modeling and are not reflected in the load forecast. Over time, as naturally occurring efficiency gains overtake the existing utility programs, these savings become part of the underlying load and no longer need to be deducted. The energy savings, however, continue to be realized on an enduring basis. Additional information on the incremental savings from new UEE programs is provided in Appendix H.

Economic Development Projects

The load forecast is also adjusted to account for expected near-term load additions resulting from large economic development projects (≥20 megawatts ("MW")) within Duke Energy Indiana's service territory. The Company's load forecasting group works closely with the economic development team to identify expected new load from potential new projects and includes a portion of this expected future load in the load forecast. Additional information on economic development as it relates to the load forecast can be found in Appendix D.

Net Load Forecast

The base, high, and low load forecasts, net of the effects of the load modifiers discussed above, are provided in the tables below. Table C-4 below provides forecasted annual energy consumption, while Table C-5 and Table C-6 below provide forecasted winter and summer peak demand, respectively. The Company used the high and low load forecasts in sensitivity analysis, evaluating potential changes to portfolio composition that may be warranted if demand were to exceed or fall below base case projections. Sensitivity analysis results are provided later in this Appendix.

Table C-4: Base, High, and Low Annual System Load Forecast (GWh)

Year	Base	High	Low
2025	33,093	37,274	31,349
2026	33,499	38,322	31,497
2027	34,447	40,354	32,128
2028	34,916	41,881	32,561
2029	34,807	42,816	32,399
2030	35,215	44,186	32,682
2031	35,537	45,503	32,871
2032	35,904	46,003	33,065
2033	36,190	46,361	33,170
2034	36,523	46,764	33,289
2035	36,876	47,185	33,421
2036	37,291	47,695	33,614
2037	37,603	48,043	33,705
2038	37,979	48,469	33,852
2039	38,363	48,898	34,007
2040	38,798	49,385	34,204
2041	39,039	49,663	34,287
2042	39,364	50,054	34,426
2043	39,719	50,486	34,582
2044	40,164	51,044	34,800

Table C-5: Base, High, and Low Load Forecast – Winter Peak (MW)

Year	Base	High	Low
2025	5,563	5,959	5,167
2026	5,503	5,949	5,100
2027	5,550	6,105	5,134
2028	5,583	6,278	5,162
2029	5,612	6,425	5,173
2030	5,650	6,584	5,188
2031	5,696	6,751	5,200
2032	5,749	6,829	5,216
2033	5,807	6,905	5,219
2034	5,869	6,990	5,227
2035	5,937	7,073	5,236
2036	6,008	7,164	5,253
2037	6,078	7,233	5,256
2038	6,150	7,311	5,267
2039	6,221	7,392	5,279
2040	6,292	7,479	5,298
2041	6,344	7,535	5,298
2042	6,401	7,604	5,305
2043	6,462	7,678	5,313
2044	6,530	7,767	5,330

Table C-6: Base, High, and Low Load Forecast – Summer Peak (MW)

Year	Base	High	Low
2025	5,972	6,570	5,681
2026	5,893	6,556	5,596
2027	5,917	6,708	5,618
2028	5,924	6,845	5,629
2029	5,934	6,982	5,641
2030	5,945	7,117	5,649
2031	5,956	7,252	5,655
2032	5,969	7,289	5,656
2033	5,989	7,326	5,660
2034	6,010	7,353	5,660
2035	6,034	7,379	5,664
2036	6,059	7,410	5,671
2037	6,087	7,486	5,678
2038	6,118	7,572	5,687
2039	6,150	7,647	5,697
2040	6,191	7,721	5,708
2041	6,247	7,770	5,717
2042	6,302	7,853	5,726
2043	6,370	7,975	5,735
2044	6,433	8,067	5,748

Existing Resources

The existing resource portfolio forms the starting point for IRP analysis, and the Company's existing fleet is described in detail in Appendix B (Duke Energy Indiana System Today). Over time, a variety of changes may be made to the existing fleet, including unit retirement, contract expiration, unit uprates or other modifications. These changes are captured in IRP analytics. Compliance with the Environmental Protection Agency ("EPA") Clean Air Act ("CAA") Section 111 May 2024 Final Rule ("EPA CAA Section 111 Rule") was a fundamental consideration in evaluating potential actions at existing resources in the 2024 IRP.

Existing Generation Retirement & Conversion Options

The EPA CAA Section 111 Rule and the compliance pathways it prescribes are described in Chapter 3. The Company determined which of these pathways may potentially be appropriate for each unit based on age, operating condition, environmental compliance requirements in addition to the EPA CAA Section 111 Rule, and other factors. Table C-7 below presents the retirement, full conversion to natural gas fuel, and coal/gas co-firing options considered for each unit. More detailed information about the generation strategies is presented later in this Appendix.

Table C-7: Existing Unit Compliance Options Under EPA CAA Section 111 Rule

Resource	Retirement	Full Natural Gas Conversion	Coal / Gas Co-firing
Cayuga 1	✓	✓	
Cayuga 2	✓	✓	
Gibson 1	✓	✓	✓
Gibson 2	✓	✓	✓
Gibson 3	✓	✓	
Gibson 4	✓	✓	
Gibson 5	✓		
Edwardsport IGCC		✓	

While the Company does not consider carbon capture and sequestration ("CCS") to be a viable option for any of its existing steam units in the timeframe required under the EPA CAA Section 111 Rule, that compliance pathway could be a potential solution at the Edwardsport integrated gasification combined cycle ("IGCC") facility. The Company evaluated a strategy variation exploring that possibility, as described in Chapter 5 (Preferred Resource Portfolio) and later in this Appendix.

Emission Rates

Table C-8 below provides the average NO_X, SO_2, Hg, and CO_2 emissions rates for each of the Company's existing generating units. Total emissions are a function of the amount of fuel burned at each facility. Forecasted total emissions vary across portfolios to a certain extent and are an output of the production cost model. Simulated total emissions for each candidate resource portfolio are provided later in this Appendix.

Table C-8: Average Emissions Rates for Existing Resources

Unit	Avg NO_X Rate (lb./MMBtu)	Avg SO_2 Rate (lb./MMBtu)	Avg Hg Rate (lb./MMBtu)	Avg CO_2 Rate (lb./MMBtu)
Cayuga 1	0.172	0.086	4×10^{-7}	205.7
Cayuga 2	0.165	0.069	4×10^{-7}	205.7
Edwardsport IGCC	0.056	0.012	–	117.0
Gibson 1	0.088	0.101	4×10^{-7}	205.7
Gibson 2	0.087	0.101	4×10^{-7}	205.7
Gibson 3	0.085	0.102	4×10^{-7}	205.7
Gibson 4	0.086	0.203	4×10^{-7}	205.7
Gibson 5	0.087	0.350	4×10^{-7}	205.7
Noblesville 3x1	0.012	–	–	117.0
Cayuga CT 4 (Gas)	0.313	–	–	117.0
Cayuga Diesel 3a-d	1.000	–	–	117.0
Henry County 1	0.112	–	–	117.0
Henry County 2-3	0.111	–	–	117.0
Madison 1-8	0.049	–	–	117.0
Vermillion 1-8	0.049	–	–	117.0
Wheatland 1-4	0.138	–	–	117.0
Purdue CHP	0.005	–	–	117.0

Note: Combined heat and power (“CHP”); Million British thermal units (“MMBtu”)

Forecasted Demand-Side Resources

Growing contributions from demand-side management (“DSM”) programs including UEE, demand response (“DR”), and Integrated Volt-VAR Control (“IVVC”) are an important part of the IRP. These demand-side resources reduce total energy needs and can be used to reduce peak load, shifting demand to lower-risk hours.

Avoided Cost for Energy Efficiency and Demand Response Screening

Duke Energy Indiana engaged Resource Innovations to develop a Market Potential Study (“MPS”) evaluating multiple scenarios for future energy savings potential. The results of the MPS inform UEE and DR resource cost and availability assumptions used in the IRP (the MPS is included with the 2024 IRP as Attachment H-1). Avoided costs used in the MPS were newly developed. The Company considers the avoided costs to be a trade secret, confidential, and competitive information. Please contact Beth Heneghan at Beth.Heneghan@duke-energy.com for more information on avoided costs.

Energy Efficiency

For IRP modeling, instead of including UEE as a load modifier reducing forecasted demand, it is included in the model as selectable resource bundles. The Company developed these energy efficiency (“EE”) bundles using the results of the MPS. For the 2024 IRP, the capacity expansion model had the option to economically select from among nine different EE bundles. These EE bundles represent programs of varying cost and size that the Company could sponsor in the future. Bundle 1 represents the current EE program. Bundles representing new programs are available for model selection in 2027, 2030, 2034, and 2042. In each of those years, the model may select one of two available bundles, a base bundle or a high bundle. The high bundle includes greater savings than the base bundle but requires more incentives to achieve those savings and therefore comes at a higher cost. The base and high bundles are mutually exclusive, and the model may select only one of the two in each year they are available. The model inputs for levelized cost, energy savings, and capacity for the various bundles can be seen below in Tables C-9 through C-11. Bundle costs are expressed dollars per megawatt-hour (“MWh”). Bundles 1-5 are the base bundles, and bundles 7-10 are the high-savings bundles. There is no “Bundle 6” because the current EE program is already in flight as approved, thus its contributions are fixed (no alternative option). Further information on customer programs is provided in Appendix H.

Table C-9: EE Bundle Costs

Bundle	Year Available	Levelized Cost ($/MWh)
1	Current	$28.86
2	2027	$32.46
3	2030	$33.28
4	2034	$27.59
5	2042	$27.59
7	2027	$51.22
8	2030	$52.72
9	2034	$43.34
10	2042	$42.68

Table C-10: EE Bundle Energy (MWh)

Bundle	1	2	3	4	5	7	8	9	10
2025	241,711	0	0	0	0	0	0	0	0
2026	357,057	0	0	0	0	0	0	0	0
2027	346,313	159,242	0	0	0	175,879	0	0	0
2028	345,809	300,285	0	0	0	347,675	0	0	0
2029	345,259	458,832	0	0	0	538,210	0	0	0
2030	344,893	458,300	170,971	0	0	552,077	189,515	0	0
2031	344,368	447,201	331,355	0	0	539,771	383,999	0	0
2032	339,736	427,710	501,615	0	0	517,952	588,577	0	0
2033	331,776	404,752	667,003	0	0	491,576	787,816	0	0
2034	310,811	385,773	654,284	165,690	0	469,005	788,779	187,261	0
2035	276,898	369,636	631,626	309,870	0	449,779	763,376	370,907	0
2036	238,165	355,947	601,601	457,076	0	434,111	729,063	556,535	0
2037	207,456	332,995	570,725	597,143	0	408,632	692,835	733,830	0
2038	183,385	305,109	543,127	724,203	0	377,008	660,513	895,995	0
2039	135,018	276,048	520,990	838,922	0	343,629	634,767	1,043,805	0
2040	71,327	254,806	493,705	944,061	0	319,410	603,569	1,180,034	0
2041	24,056	240,920	457,218	1,042,150	0	303,720	562,266	1,307,403	0
2042	8,661	204,833	422,337	977,485	156,494	259,851	522,610	1,252,343	174,868
2043	8,272	148,894	387,071	936,471	279,442	191,127	482,442	1,205,502	331,403
2044	7,212	88,496	359,657	884,773	402,536	116,785	451,044	1,146,623	487,545

Table C-11: EE Bundle Capacity (Max Contribution, MW)

Bundle	1	2	3	4	5	7	8	9	10
2025	46	0	0	0	0	0	0	0	0
2026	67	0	0	0	0	0	0	0	0
2027	66	33	0	0	0	38	0	0	0
2028	66	59	0	0	0	73	0	0	0
2029	66	89	0	0	0	111	0	0	0
2030	66	89	37	0	0	110	43	0	0
2031	66	88	67	0	0	108	83	0	0
2032	65	84	99	0	0	104	124	0	0
2033	63	81	131	0	0	99	165	0	0
2034	59	76	128	36	0	95	162	41	0
2035	52	73	125	63	0	91	157	77	0
2036	44	69	120	90	0	87	150	113	0
2037	38	67	114	117	0	83	144	147	0
2038	34	62	108	140	0	78	137	178	0
2039	27	57	103	162	0	72	132	208	0
2040	16	51	98	182	0	68	126	234	0
2041	7	49	92	201	0	65	119	259	0
2042	2	47	86	191	34	58	112	251	39
2043	2	39	80	183	58	46	105	242	70
2044	2	28	74	173	81	33	99	231	100

Demand Response

As mentioned in Chapter 3, the Company included DR programs in the 2024 IRP modeling. DR capacity is modeled as a peaking resource like traditional generation and contributes to capacity reserve margins. DR capacity is grossed up for reserve margin and transmission losses. Contributions from DR are forecasted rather than model-selectable. The annual capacity and energy for all DR programs are provided below in Table C-12 and Table C-13. Further information on DR programs can be found in Appendix H.

Table C-12: DR Annual Capacity by Program (Max Contribution, MW)

Year	DR Total	Interruptible	Power Manager for Business	Power Manager	PowerShare	New Undesignated DR
2025	526	233	3	62	227	0
2026	525	233	4	66	222	0
2027	531	233	5	70	222	0
2028	536	233	7	74	222	0
2029	540	233	7	78	222	0
2030	542	233	7	78	222	2
2031	545	233	7	79	222	5
2032	548	233	7	79	222	8
2033	551	233	7	79	222	11
2034	554	233	7	79	222	14
2035	557	233	7	79	222	17
2036	560	233	7	79	222	20
2037	563	233	7	79	222	23
2038	567	233	7	79	222	26
2039	570	233	7	79	222	29
2040	573	233	7	79	222	32
2041	576	233	7	79	222	35
2042	579	233	7	79	222	38
2043	582	233	7	80	222	41
2044	585	233	7	80	222	44

Table C-13: DR Annual Energy by Program (MWh)

Year	DR Total	Interruptible	Power Manager for Business	Power Manager	PowerShare	New Undesignated DR
2025	44	43.34	0	1	0	0
2026	48	47.53	0	1	0	0
2027	50	48.73	0	1	0	0
2028	47	45.97	0	1	0	0
2029	48	46.86	0	1	0	0
2030	48	47.42	0	1	0	0
2031	49	47.24	0	1	0	0
2032	51	49.54	0	1	0	1
2033	48	46.31	0	1	0	1
2034	49	46.31	0	1	0	1
2035	50	46.77	0	1	0	2
2036	49	46.28	0	1	0	2
2037	51	46.91	0	1	0	3
2038	52	48.04	0	1	0	3
2039	50	45.99	0	1	0	3
2040	51	46.30	0	1	0	4
2041	52	47.13	0	1	0	4
2042	52	46.31	0	1	0	4
2043	53	47.31	0	1	0	5
2044	53	46.69	0	1	0	5

Integrated Volt-VAR Control

IVVC deployment projects are ongoing throughout the Duke Energy Indiana service territory, and the associated reduction in load is included in modeling as a prescribed supply-side resource. The IVVC program is expected to reduce upcoming demands on the distribution system by 0.69% in 2024, growing to 0.8% by 2028. These load reduction percentages are used to derive an hourly dispatch profile and maximum capacity for the IVVC resource, determining energy and capacity savings. Table C-14 below shows the annual capacity and energy for the modeled IVVC resource.

Table C-14: IVVC Annual Capacity and Energy

Year	Capacity (MW)	Energy (MWh)
2025	41	226
2026	43	242
2027	45	261
2028	45	267
2029	46	272
2030	46	275
2031	46	276
2032	46	278
2033	46	280
2034	46	282
2035	46	285
2036	47	288
2037	47	290
2038	48	293
2039	49	297
2040	49	300
2041	50	302
2042	50	305
2043	50	308
2044	51	311

Prescribed Supply-Side Resources

Resource planning is a continuous, iterative process. At the time a given IRP is developed, certain projects will be in progress, under contract, or otherwise reasonably expected to be added to the Company's portfolio at some specified point in the future. The Company prescribes these "in flight" resources in all IRP portfolios. Once such project prescribed in the 2024 IRP is the 199 MW Speedway solar project, which is expected to be completed in late 2025 (online by the beginning of 2026 for modeling purposes).

Selectable Supply-Side Resources

This section discusses each of the generic supply-side resources that the capacity expansion model can economically select to develop a portfolio. The capacity expansion model selects resources that minimize the cost of the system, subject to meeting the requirements of the system, including energy and capacity requirements, market purchase and sale limitations, and operating reserve requirements. Each resource type has unique costs and benefits, and the model weighs each one against the needs of the system. Dispatchability, ramp rates, minimum loads, cycle times, efficiency, availability (both when a resource can be brought online and how much can be integrated to the portfolio), and seasonal capacity value are all important factors that can influence resource selection.

While each resource type may be deployed in a variety of project sizes and configurations, standardized generic units are used in IRP analysis. The size, quantity, capability, cost, and timing of generic resource additions in the IRP may differ from actual project implementation based on site-specific considerations, project availability during plan execution, or other project-specific factors.

In IRP modeling, resources are added, removed, or otherwise changed on an annual basis. Duke Energy Indiana uses beginning-of-year ("BOY") convention, meaning portfolio changes are assumed to occur on January 1 of each year. Resource additions and retirements are presented on a BOY basis in this IRP, and changes are said to occur "by" a given year. Model inputs for each resource type are discussed in more detail below.

Solar & Solar Paired with Storage

Since resources in the Plan are meant to be generic, the Company included only one variation each of solar and solar paired with storage for model selection. These resources have a fixed hourly generation profile based on the generic resource configuration and local irradiance data. The Company confirmed that its cost projections for solar align with the market by benchmarking its forecast against the actual costs of projects bid into its ongoing procurement process. The cost forecast incorporates the expectation that solar technology will continue to mature over the short term, delivering cost declines. Resource capital costs are presented in Chapter 3. Table C-15 below presents the assumptions for both the solar and solar paired with storage resources.

Table C-15: Solar and Solar Paired with Storage Modeling Assumptions

	Solar	Solar Paired with Storage (50% Battery Ratio)
Fuel	N/A	N/A
Selection Increment (Installed Capacity, MW-AC)	50 MW	50 MW
Solar DC / AC Ratio[1]	1.4	1.4
Capacity Factor	24.83%	24.83%[2]
Paired Storage Technology	N/A	Li-ion Battery
Storage Power Capacity	N/A	25 MW (50% ratio to solar)
Storage Duration		4 hours
Storage Energy Capacity	N/A	100 MWh
Dispatchability	Fully Curtailable Down	Fully Curtailable Down
Asset Life	30 Years	30 Years
First Year of Eligible Selection	2027	2028
Battery Charging from Grid	N/A	Yes

Note 1: Direct current ("DC"); Alternating current ("AC")
Note 2: Capacity factor for solar does not account for clipped energy used to charge the paired battery.

Table C-16 below provides the shared total annual resource availability for solar and solar paired with storage.

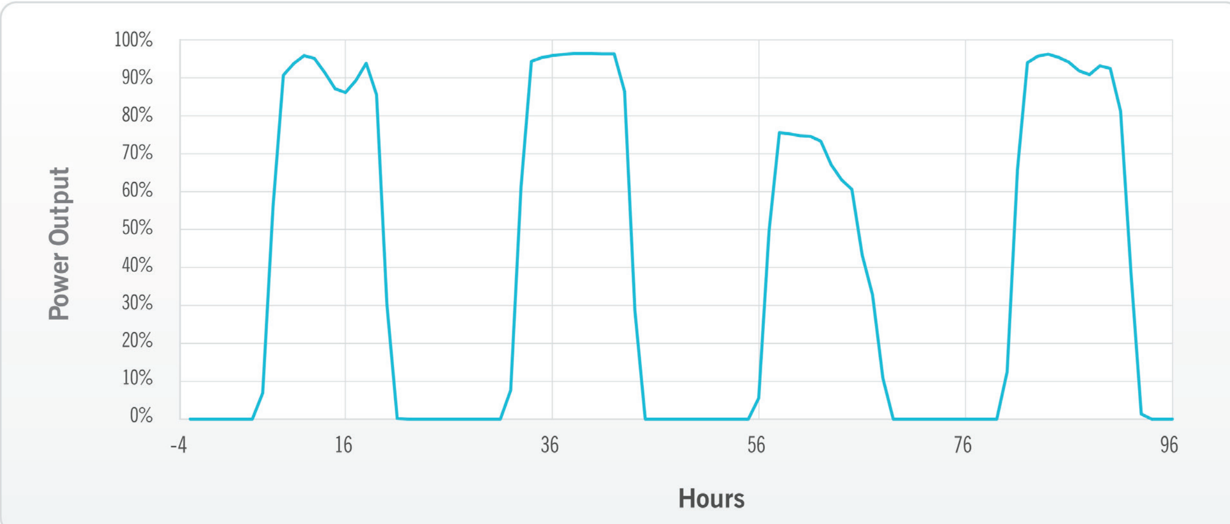
Table C-16: Annual Availability of Solar and Solar Paired with Storage Resources (MW)

Selection Year	Solar[1]	Paired Storage[2]
2027	300	–
2028	1,150	575
2029	1,400	700
2030-2031	1,600/yr	800/yr
2032+	1,800/yr	900/yr

Note 1: Solar resource availability includes standalone solar and solar paired with battery storage.
Note 2: Storage resource availability includes battery storage paired with solar. Standalone battery storage availability is provided below.

Figure C-5 below shows a sample of the generic hourly generation profile for solar.

Figure C-5: Generic 96-Hour Solar Profile



Standalone Battery & Long-Duration Energy Storage

The Company included lithium-ion ("Li-ion") batteries for model selection in all planning scenarios for the 2024 IRP. Long-duration energy storage ("LDES") was included as a selectable option in the Aggressive Policy & Rapid Innovation Worldview. Table C-17 below provides a summary of model assumptions for energy storage.

Table: C-17: Storage Modeling Assumptions

	Standalone 4-Hr Li-ion Battery	10-Hr LDES[1]	100-Hr LDES[1]
Charging Ability	Grid-Tied	Grid-Tied	Grid-Tied
Selection Increment (Installed Storage Power Capacity)	50 MW	100 MW	100 MW
Storage Energy Capacity	200 MWh	1,000 MWh	10,000 MWh
Round-Trip Efficiency	85%	75%	43%
Replenishment Strategy	Rebuild after 15 years	N/A	N/A
Dispatchability	-50 MW to 50 MW	-100 MW to 100 MW	-100 MW to 100 MW
Asset Life	30 Years	30 Years	30 Years
First Year of Eligible Selection	2028	2030	2032

Note 1: LDES is model-selectable in the Aggressive Worldview only.

Table C-18 below presents the availability assumptions for standalone energy storage resources.

Table C-18: Annual Availability of Standalone Storage Resources (MW)

Selection Year	Standalone 4-Hr Li-ion Battery	10-Hr LDES[1,2]	100-Hr LDES[1,2]
2025-2027	–	–	–
2028-2029	300/yr	–	–
2030-2031	700/yr	500/yr	–
2032+	700/yr	500/yr	100/yr

Note 1: LDES is model-selectable in the Aggressive Worldview only.
Note 2: No more than 500 MW total LDES (10-hour and 100-hour combined) can be selected per year.

Simple Cycle Combustion Turbines

The Company uses a natural gas-fired advanced class simple cycle combustion turbine (“CT”) as the generic CT resource in IRP modeling. This is the most efficient and flexible combustion technology available. The cost of the generic CT reflects its dual-fuel capability and includes the cost of storage for three days’ worth of fuel oil. To allow more granularity in the capacity expansion model, the Company made CTs selectable in half-unit increments. Table C-19 below provides a summary of modeling assumptions for CTs.

Table C-19: Combustion Turbine Modeling Assumptions

	Advanced Class CT
Primary Fuel	Natural Gas
Backup Fuel	#2 Fuel Oil
Selection Increment (Installed Capacity, Winter)	213 MW
Heat Rate (Max, Winter)	9157 Btu/kWh[1]
CO_2 Emissions (lb/MMBtu)	117
NOx Emissions (lb/MWh)	0.095
Dispatchability	Min Load to Max Load
Asset Life	35
First Year of Eligible Selection	2031
Cumulative Addition Availability	4 (half units) per year through 2037, 8 Total

Note 1: British thermal unit (“Btu”); kilowatt-hour(“kWh”)

Table C-20 below presents the availability assumptions for combustion turbine generators. In the Aggressive Worldview, hydrogen-fueled advanced class simple cycle CTs were made available for selection, also in half-unit increments.

Table C-20: Annual Availability of Combustion Turbine Generators (MW)

Selection Year	CT	Hydrogen CT[1]
2031-2037	850/yr	850/yr
2038+	–	850/yr

Note 1: Hydrogen CT is model-selectable in the Aggressive Worldview only.

Combined Cycle Power Blocks

The Company used three different generic combined cycle ("CC") power blocks in the 2024 IRP: (1) 1x1 advanced class CC unit with duct firing, (2) 2x1 advanced class CC unit with duct firing, and (3) 2x1 advanced class CC unit with duct firing and CCS. Table C-21 below provides modeling assumptions for these resources.

Table C-21: Combined Cycle Modeling Assumptions

	1x1 CC	2x1 CC	2x1 CC with CCS
Primary Fuel	Natural Gas	Natural Gas	Natural Gas
Selection Increment (Installed Capacity, Winter)	719 MW	1438 MW	1,215 MW
Heat Rate (Max, Winter)	6,719 Btu/kWh	6,550 Btu/kWh	7,569 Btu/kWh
CO_2 Emissions (lb/MMBtu)	117	117	6
NOx Emissions (lb/MWh)	0.052	0.052	0.052
Dispatchability	Min Load to Max Load	Min Load to Max Load	Min Load to Max Load
Asset Life	35 Years	35 Years	35 Years
First Year of Eligible Selection	2030	2032	2035
Cumulative Addition Availability	1 per year from 2030-2032, 3 per year 2033-2037 Max of 6 total	2 per year, only in 2032 Max of 2 total	1 per year Max of 2 total (1 in 2035-2039, 1 in 2040-2044)

Table C-22 below presents the availability assumptions for combined cycle generators.

Table C-22: Annual Availability of Combined Cycle Generators (MW)

Selection Year	1x1 CC	2x1 CC	2x1 CC with CCS
2030-2031	719/yr	–	–
2032	719	2,876	–
2033-2034	2,157/yr	–	–
2035-2037	2,157/yr	–	1,215/yr
2038+	–	–	1,215/yr

Onshore Wind

Duke Energy Indiana developed a generic wind generation profile using historical wind speed data collected over a 20-year period at multiple locations and heights within the Company's service territory. The Company used a best-fit methodology to produce an 8760-hour wind speed profile that it then converted into a generation profile using manufacturer-supplied power curves for the representative turbine technology. Table C-23 below summarizes modeling assumptions for wind resources.

Table C-23: Onshore Wind Modeling Assumptions

Onshore Wind	
Fuel	N/A
Selection Increment (Installed Capacity)	50 MW
Capacity Factor	31.58%
Dispatchability	Fully Curtailable Down
Asset Life	30 Years
First Year of Eligible Selection	2028

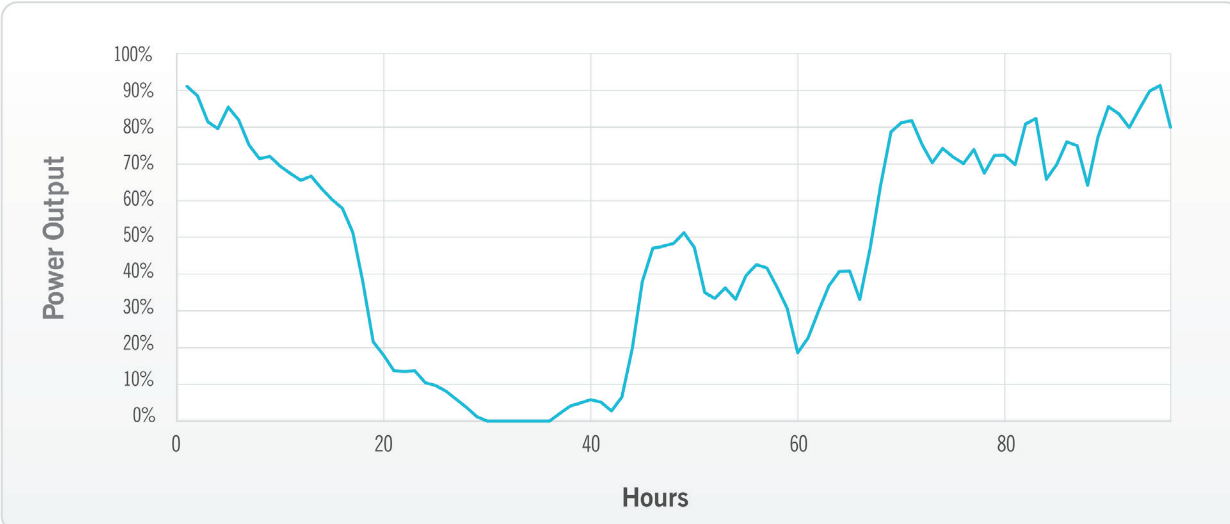
Table C-24 below presents the availability assumptions for onshore wind resources.

Table C-24: Annual Availability of Onshore Wind Resources (MW)

Selection Year	Wind
2025-2027	–
2028-2029	200/yr
2030-2031	300/yr
2032+	400/yr

Figure C-6 below shows a sample from the generic wind profile over a four-day span in the winter.

Figure C-6: Generic 96-hour Wind Profile



Advanced Nuclear – Small Modular & Advanced Reactors

The Company included two types of advanced nuclear resource options for model selection in the 2024 IRP – small modular reactors ("SMR") and advanced reactors ("AR") with thermal energy storage. A detailed discussion of these technologies is provided in Appendix F (Supply-Side Resources). Table C-25 below presents the assumptions for nuclear units in the model.

Table C-25: Advanced Nuclear Modeling Assumptions

	SMR	AR
Reactor Selection Increment (Installed Capacity)	300 MW	300 MW
Thermal Storage Selection Increment (Installed Capacity)	N/A	150 MW
Heat Rate (Max, Winter)	10,551	8,441
Dispatchability	Min Load to Max Load	Min Load to Max Load
Asset Life	60 Years	60 Years

For the 2024 IRP analysis, the Company assumed that the first SMR could be available by 2037, allowing model selection of up to four 300 MW blocks per year through the end of the study period. The Company assumed that ARs could be available by 2039, with a total of two blocks available per year through the end of the study period. The MW available in each year are shown in Table C-26 below.

Table: C-26: Annual Availability of Advanced Nuclear Resource (MW)

Selection Year	SMR	AR
2037-2038	1,200/yr	–
2039+	1,200/yr	900/yr (600 MW nuclear and 300 MW storage)

Generic Capacity Purchase Agreements

The Company continually evaluates emerging opportunities to pursue prudent incremental supply-side and demand-side resources that can meet growing customer needs. A variety of options could be available to meet capacity needs during the period before the first new resources can be brought online. For the purposes of generic IRP modeling, the Company included a generic capacity-only resource as a selectable option from 2025-2027 in the 2024 IRP. This resource has a one-year life and is similar to a capacity contract renewable on an annual basis.

The cost of this generic resource for modeling purposes was based on the highest clearing price in the 2024/2025 MISO Planning Resource Auction. Zone 5 cleared at seasonal Cost of New Entry ("CONE"), $720/MW-day, for fall and spring.[3] The Company deliberately sets a high cost for this resource to ensure that the model selects it only as a last resort.

Transmission Costs

The 2024 IRP modeling includes two types of transmission costs. First, consistent with previous IRPs, the generic capital cost for each resource type includes the cost of interconnection facilities. Second, the Company developed and included generic transmission network upgrade costs for all resources as a proxy for costs that could be assigned in MISO's Definitive Planning Phase study process. The proxy transmission network upgrade cost of $0.275/watt, levelized over the life of the resource, is $20.875/kilowatt-year (2024$).

Resources that would use the same electrical point of interconnection as retiring assets (i.e., CCs brought online by 2032) and therefore could take advantage of MISO's Generator Replacement Request process are not burdened with this cost. As with other costs, actual transmission network upgrade costs will vary by project. These transmission costs are discussed further in Appendix I (Transmission Planning).

[3] MISO, Planning Resource Auction Results for Planning Year 2024-25, April 26, 2024, available at https://cdn.misoenergy.org/2024+PRA+Results+Posting+20240425632665.pdf.

Inflation Reduction Act of 2022

The Inflation Reduction Act of 2022 ("IRA") and related key assumptions are described in Chapter 3.

Table C-27 below provides the investment tax credit ("ITC") percentages used in the 2024 IRP analysis for each applicable resource type.

Table C-27: ITC Percentages by Resource

Resource	ITC % on Total Project Capital
Solar Paired with Storage	13%[1]
Advanced Nuclear	36%[2]
Standalone Storage	40%
10-Hour Long-Duration Storage	40%
100-Hour Long-Duration Storage	40%

Note 1: The 13% ITC for solar paired with storage reflects 36% credit for the storage component of the resource prorated by the portion of total project capital cost specific to storage.
Note 2: Assumes cost of transfer equates to 10% of total ITC value.

Each production tax credit ("PTC")-eligible resource was given one of three levels of PTC credit dependent on expected siting and supply chain expectations. This resulted in three different PTC schedules, which are provided in Table C-28 below. PTC-eligible resources include standalone solar, wind, and the solar component of solar paired with storage. To ensure the model considers the final net PTC pay in capacity expansion runs, the PTC rate modeled must be grossed up for taxes with the Company's projected income tax rate.

Table C-28: Modeled PTC by Year, Reflecting Gross-Up ($/MWh)

Year	Base PTC	PTC with Energy Community Bonus	PTC with Domestic Content and Energy Community Bonuses
2025	39.93	42.33	46.32
2026	41.26	43.74	47.86
2027	41.26	43.74	47.86
2028	42.59	45.15	49.41
2029	42.59	45.15	49.41
2030	43.92	46.56	50.95
2031	45.26	47.97	52.50
2032	45.26	47.97	52.50
2033	46.59	49.38	54.04
2034	47.92	50.79	55.58
2035	49.25	52.20	57.13
2036	49.25	52.20	57.13
2037	50.58	53.61	58.67
2038	51.91	55.03	60.22
2039	53.24	56.44	61.76
2040	53.24	56.44	61.76
2041	54.57	57.85	63.30
2042	55.90	59.26	64.85
2043	57.23	60.67	66.39
2044	58.57	62.08	67.94

The Company also assumes that all projects eligible for IRA tax credits will qualify for five-year modified accelerated cost recovery system ("MACRS") for tax depreciation. In addition, the Company assumes solar credits for IRA Sections 45Y and 48E will not phase out during the 20-year IRP planning period. The IRA states that credits will phase out in "the year after 2032" or when electric power sector greenhouse gas ("GHG") emissions achieve a 75% reduction from 2022 levels.[4] Based on its review of studies from Rhodium, REPEAT, Resources for the Future, Energy Innovation and other recent IRPs, Duke Energy Indiana does not expect 75% reduction from 2022 levels to be reached until the mid-2040s at the earliest. Given the uncertainty around that date and the safe harbor provision

[4] Department of Energy Loan Program Office, Inflation Reduction Act of 2022, August 16, 2022. https://www.energy.gov/lpo/inflation-reduction-act-2022.

extending the availability for tax credit eligibility, it is appropriate to assume no phase-out of IRA credits over the planning horizon for purposes of IRP analytics.

Fuel Price Forecasts

The company developed base case, low, and high price forecasts for coal and natural gas that it used in both the national data base and “local” model runs. In addition to “base” fuel price forecast, alternate fuel price forecasts for natural gas and coal are detailed below.

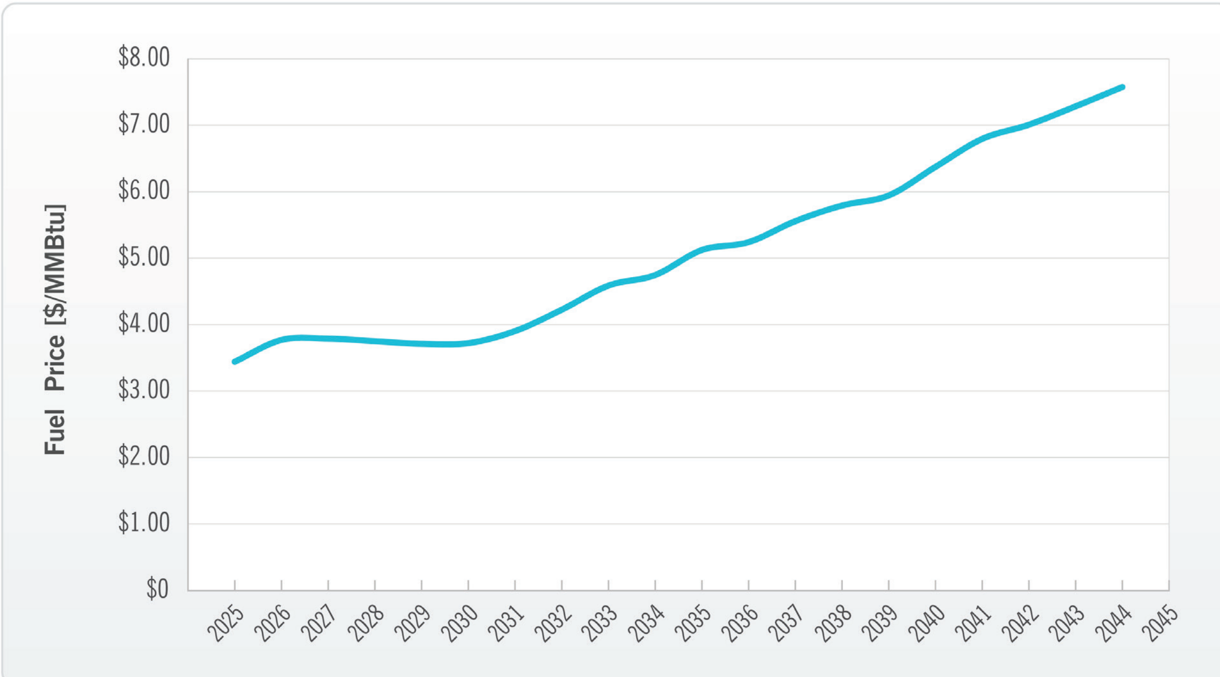
Natural Gas Price Forecast

The Company’s base natural gas price forecast uses five years of natural gas market data (2025-2029), followed by a three-year transition from market-based pricing to fundamentals-based pricing (2030-2032), and fully fundamentals-based pricing starting in 2033 and running through the end of the planning period. Natural gas price forecasts vary among fundamentals providers and can be significantly impacted by the assumptions made in each provider’s forecast and the date by which it was issued. To reduce reliance on any one set of assumptions and to diversify the information supporting the gas price forecast for the 2024 IRP, the Company developed the fundamentals-based natural gas price forecast for the IRP using the average of four recent Henry Hub price forecasts from different providers. These were:

- Energy Information Administration’s (“EIA”) Annual Energy Outlook (“AEO”) Reference Case (March 2023)
- S&P Global North American Natural Gas Long-Term Outlook (February 2024)
- Energy Ventures Analysis (“EVA”) Market Outlook (Fall 2023)
- Wood Mackenzie Gas Market Outlook (Spring 2024)

The resulting Henry Hub natural gas price forecast used in the 2024 IRP modeling, consisting of the near-term market-based forecast, the three-year transition, and finally the full fundamentals-based price forecast (an average of the price forecast of the four different fundamentals providers discussed above) is shown in Figure C-7 below. The Company based delivered gas prices for each gas-fired generating unit on the Henry Hub forecast.

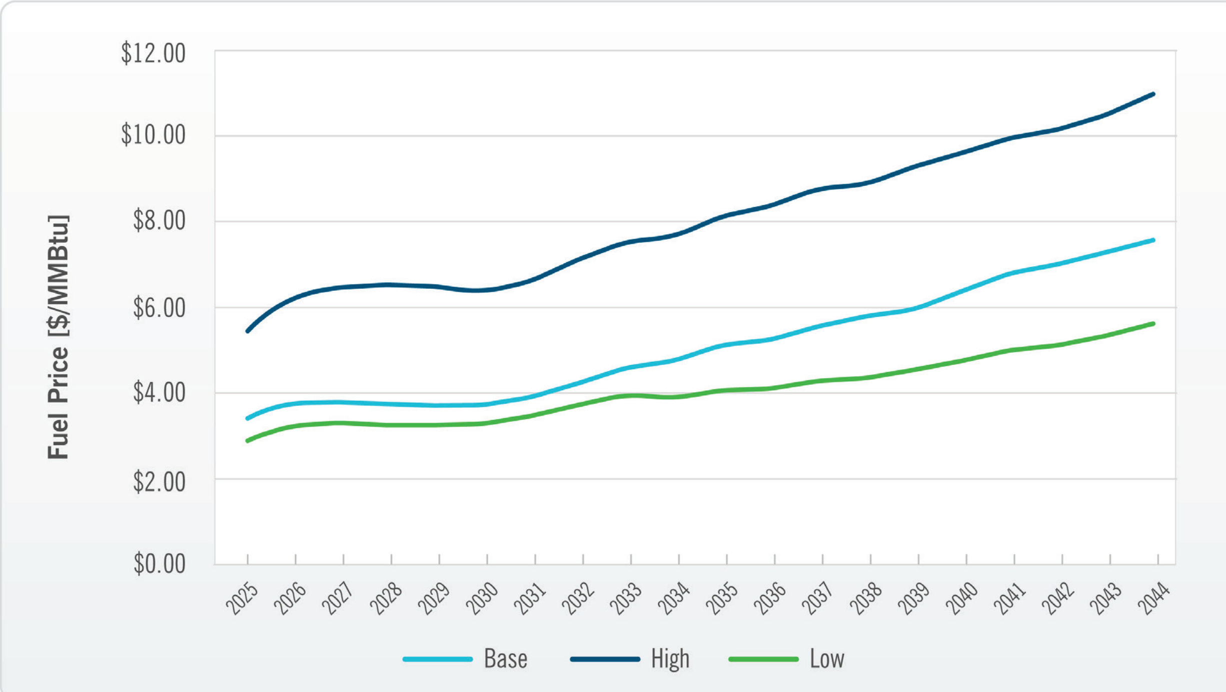
Figure C-7: Base Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



Alternate Natural Gas Price Forecasts

The Company developed high and low natural gas price forecasts for IRP sensitivity analysis using the EIA's AEO "side cases." The EIA develops these side cases as part of the AEO to explore the potential impacts of changes to certain assumptions around which there is much uncertainty. The Company developed the high natural gas price forecast for the 2024 IRP by multiplying its base case forecast by the ratio of the natural gas price in EIA's Low Oil and Gas Supply-side case to the AEO Reference Case. Similarly, the Company developed the low natural gas price forecast by multiplying its base case forecast by the ratio of the High Oil and Gas Supply-side case to the AEO Reference Case. Figure C-8 below shows the resulting high and low natural gas price forecasts compared to the Company's base forecast.

Figure C-8: Alternate Natural Gas Price Forecasts (Nominal $/MMBtu)



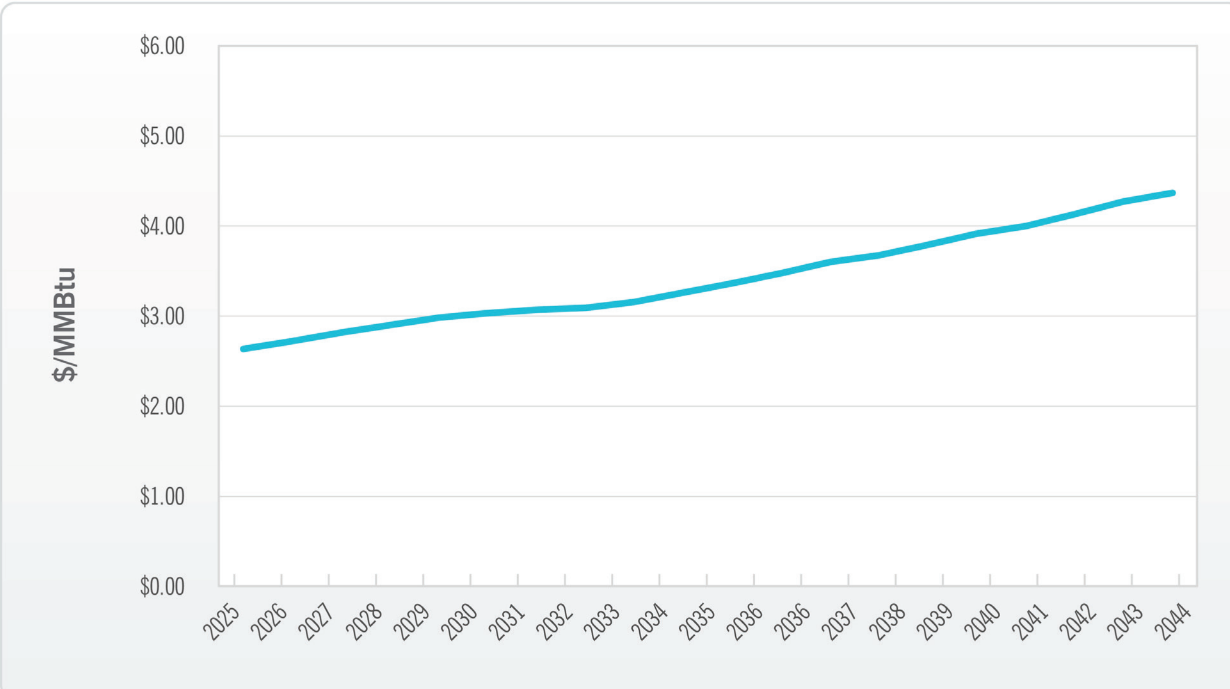
Coal Price Forecast

The Company's base coal price forecast uses five years of market pricing (2025-2029), followed by a three-year transition from market-based pricing to fundamentals-based pricing (2030-2032), and fully fundamentals-based pricing beginning in 2033 through the end of the planning period. Coal price forecasts vary among fundamentals providers and can be significantly impacted by the assumptions made in each provider's forecast and the date by which it was issued. To reduce reliance on any one set of assumptions and to diversify the information supporting the coal price forecast, the Company developed the fundamentals-based coal price forecast for the 2024 IRP using the average of four recent coal price forecasts from different providers. These were:

Figure C-9 below shows the average of the base case delivered coal prices for the Company's fleet.

- EIA AEO Reference Case (March 2023)
- McCloskey U.S. Coal Market Briefing (March 2024)
- EVA Market Outlook (Fall 2023)
- Wood Mackenzie Coal Market Outlook (Spring 2024)

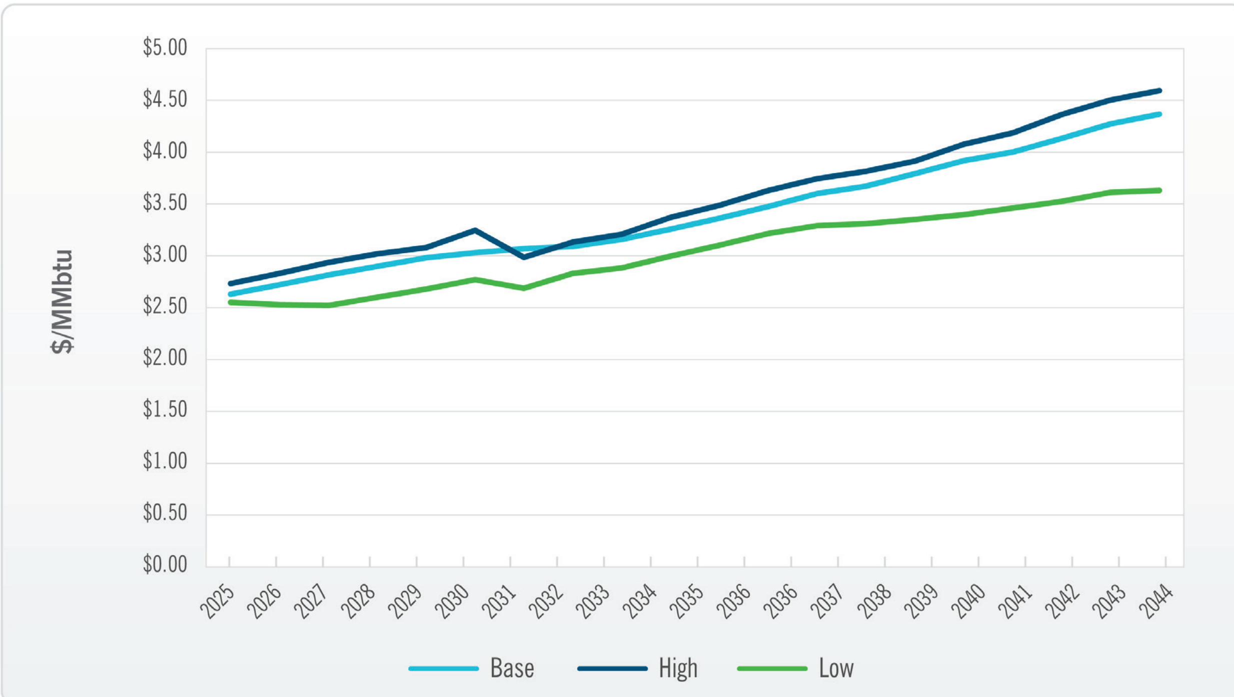
Figure C-9: Base Case Coal Price Forecast
(Average Delivered Price Across Fleet, Nominal $/MMBtu)



Alternate Coal Price Forecast

The Company developed its high and low coal price forecasts using a similar method to that used to develop alternate natural gas price forecasts described above, relying on the ratio of coal prices in the EIA's AEO side cases to the AEO Reference Case. The Company developed the low coal price forecast using the ratio between the Low Gas and Oil Supply-Side case and the AEO Reference Case. The high coal price forecast was developed using the ratio between the High Gas and Oil Supply-Side case and the AEO Reference Case. Figure C-10 below shows the high and low coal price forecasts as well as the base case.

Figure C-10: Alternate Coal Price Forecasts (Average Delivered Price Across Fleet, Nominal $/MMBtu)



Note: The alternate fuel price forecasts are derived from the EIA AEO 2023 High Gas Supply and Oil sensitivity and Low Gas Supply and Oil sensitivity. The high coal price drops below the base price due to this dependency on EIA's forecasted gas supply.

The alternate coal price forecasts shown in the figure above are based on third-party forecasted sensitivities to changes in natural gas supply. The potential coal price and supply chain impacts of the domestic power industry's transition away from coal fuel cannot be known today. As the transition proceeds, risks related to coal production, transportation rates, and potential regulation on mining of and power generation from coal will increase. The potential price impacts of one or more of these risks being realized is unpredictable.

Power Prices

Duke Energy Indiana developed separate power price forecasts for the three planning scenarios, the "No 111" Strategy Variation, and the High Fuel Price and Low Fuel Price sensitivity analysis cases. The planning scenarios are described in Chapter 2, and power price development is described in Chapter 3. Figures C-11 and C-12 below provide the round-the-clock ("RTC") average power price forecasts for the worldviews, the "No 111" case and the fuel price sensitivity cases.

Figure C-11: Annual RTC Power Prices for the Worldviews

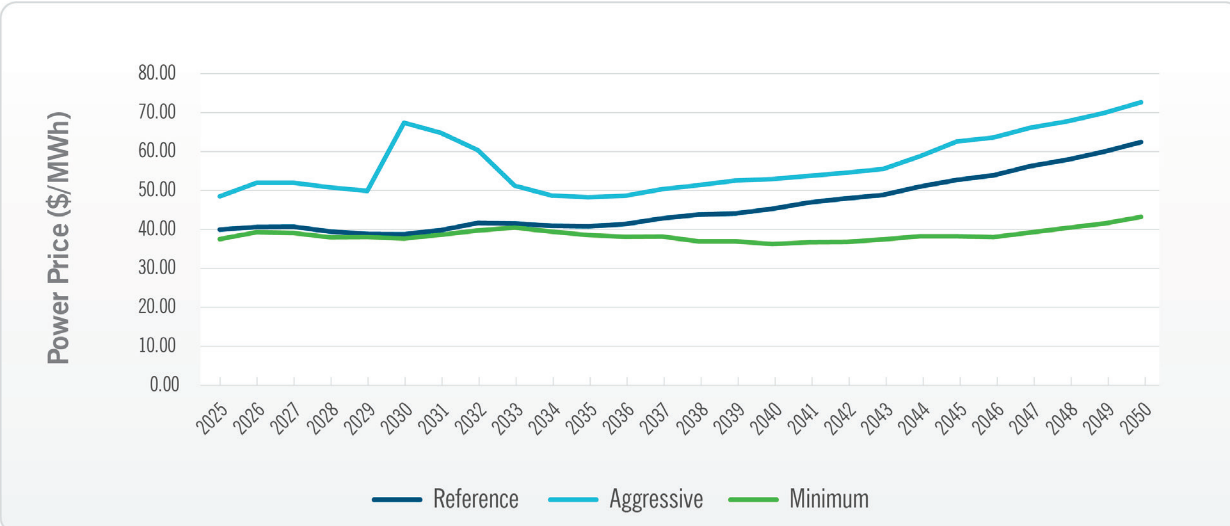
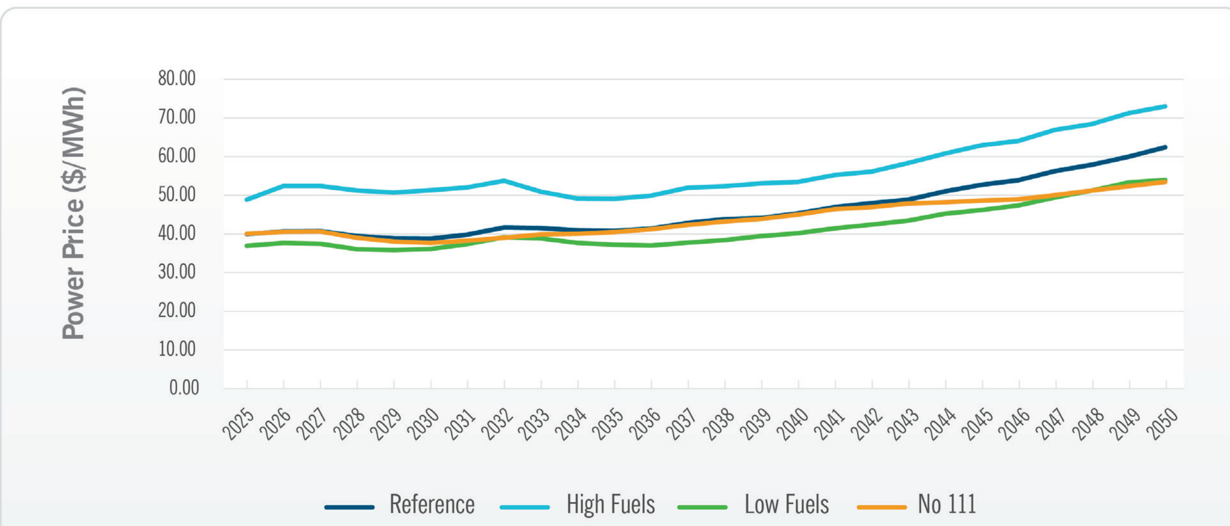


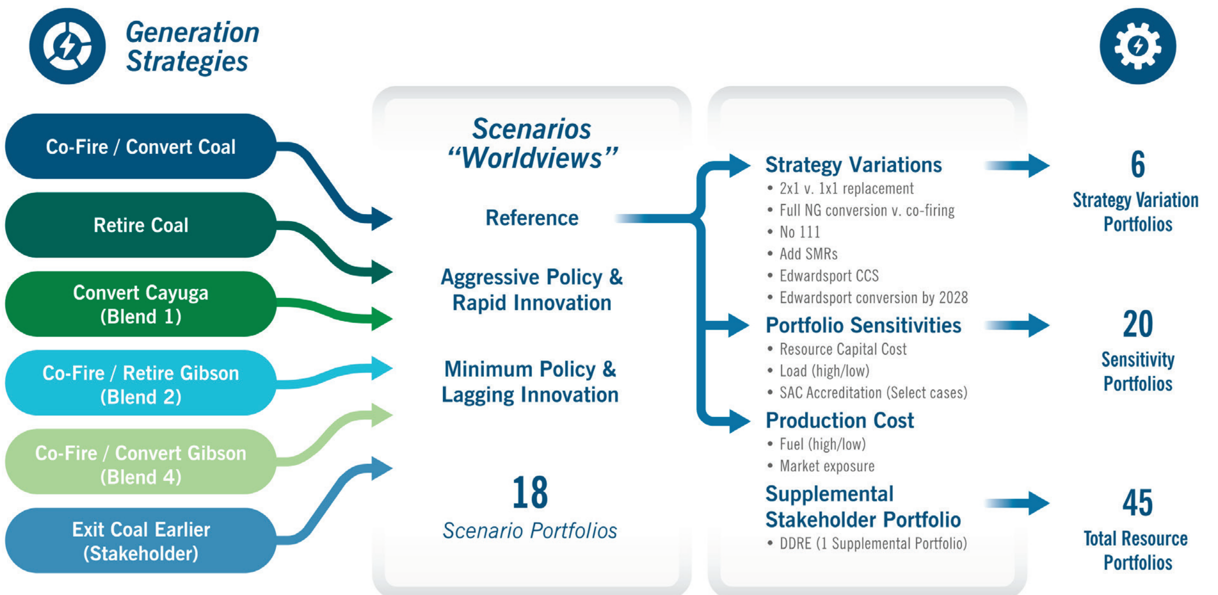
Figure C-12: Annual RTC Power Prices for No 111, High Fuel Price, and Low Fuel Price Cases



Analytical Framework

The analytical framework developed by the Company for the 2024 IRP, consisting of generation strategies, planning scenarios or "worldviews," strategy variations, and sensitivity analyses, is described in Chapter 2. This framework is illustrated in Figure C-13 below. Figure C-14 below summarizes the 2024 IRP generation strategies.

Figure C-13: 2024 IRP Analytical Framework



Note: Natural gas ("NG") conversion; ("DDRE") denotes the Deep Decarbonization & Rapid Electrification stakeholder-inspired portfolio discussed later in this Appendix.

Figure C-14: Summary of Generation Strategies and "No 111" Strategy Variation

<table>
<tr><th>UNIT</th><th>Convert/ Co-Fire Coal</th><th>Retire Coal</th><th>Blend 1</th><th>Blend 2</th><th>Blend 4</th><th>Exit Coal Earlier (Stakeholder)</th><th>No 111</th></tr>
<tr><td>Cayuga 1</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="6">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td colspan="2">Retire by 1/1/2030</td><td rowspan="2">NG Conversion by 1/1/2029</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Cayuga 2</td><td colspan="2">Retire by 1/1/2031</td></tr>
<tr><td>Gibson 1</td><td rowspan="2">Co-fire by 1/1/2030</td><td rowspan="4">Retire by 1/1/2032</td><td colspan="2" rowspan="2">Co-fire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">Retire by 1/1/2036</td></tr>
<tr><td>Gibson 2</td></tr>
<tr><td>Gibson 3</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td><td rowspan="2">NG Conversion by 1/1/2030</td><td rowspan="2">Retire by 1/1/2030</td><td rowspan="2">Retire by 1/1/2032</td></tr>
<tr><td>Gibson 4</td></tr>
<tr><td>Gibson 5</td><td colspan="7">Retire by 1/1/2030</td></tr>
<tr><td>Edwardsport</td><td colspan="6">NG Conversion by 1/1/2030</td><td>NG Conversion by 1/1/2035</td></tr>
</table>

Worldviews

The Company developed three worldviews for the 2024 IRP, consisting of the Reference Scenario ("Reference Case"), the Aggressive Policy & Rapid Innovation Worldview ("Aggressive Worldview"), and the Minimum Policy & Lagging Innovation Worldview ("Minimum Worldview"). The assumptions underpinning each worldview are described in Chapter 2 and summarized in Table C-29 below. These assumptions are further defined in Chapter 3 and additional detail on the alternate assumptions used in the Aggressive and Minimum worldviews is provided below.

Table C-29: Summary of Worldview Assumptions

	EPA CAA Section 111 Rule	Coal Price	Gas Price	IRA	Resource Availability (interconnection timing)	CO_2 Tax	Renewables & Storage Cost	Distributed Energy Resources (incl. BTM)	Emerging Technology
Aggressive Policy & Rapid Innovation	Final Rule + Existing Gas	High	High	Extend + Additional Domestic Content	High Renewables Availability in Long Term	Yes	Low	High	Long-duration energy storage & H_2 available
Reference	Final Rule	Base	Base	Extend	Base	No	Base	Base	Base
Minimum Policy & Lagging Innovation	Repeal	Low	Low	Repeal	Base	No	Base	Low	Advanced Nuclear not available

The Company used the base load forecast for each planning scenario and evaluated alternate load forecasts in portfolio sensitivity analysis as described below.

Environmental Protection Agency Clean Air Act Section 111 Rule

Details of EPA CAA Section 111 Rule, which was finalized in May 2024, can be found in Appendix J (Environmental Compliance), and related modeling assumptions are described in Chapter 3. The Company used different assumptions related to the rule for each of its planning scenarios.

- **Reference Scenario:** Final rule as written. New CCs and CTs are limited to 40% capacity factor ("CF") starting in 2032.
- **Aggressive Worldview:** Assumes final rule as written as well as additional regulation of existing natural gas combustion turbines. New CCs and CTs are limited to 40% CF starting in 2032. Existing CTs are limited to 20% CF throughout the study period.
- **Minimum Worldview:** Rule does not survive legal challenges. No CF limit for CCs or CTs.

Renewable & Energy Storage Capital Costs

The Company used the base case capital cost forecasts for renewable energy and battery energy storage resources in both the Reference Scenario and Minimum Worldview. For the Aggressive Worldview, the Company assumed more aggressive cost decline trajectories. A comparison of the base and aggressive cost forecasts is shown in Figures C-15 through C-17 below. As explained in Chapter 3, capital costs are shown by the year in which a project is begun.

Figure C-15: Capital Cost Forecasts for Solar

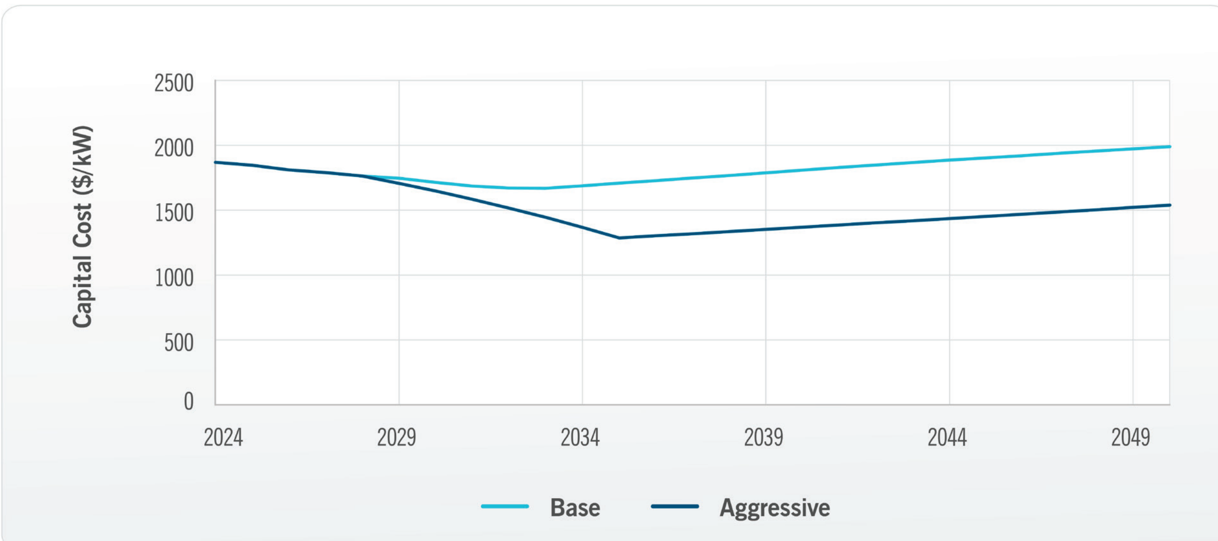


Figure C-16: Capital Cost Forecasts for Battery Energy Storage

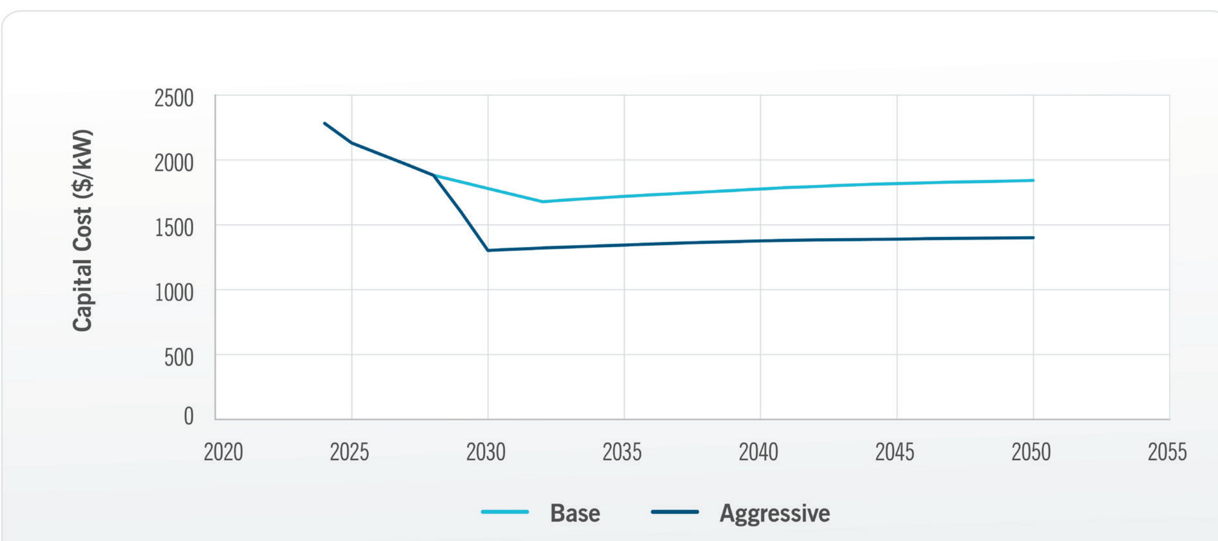
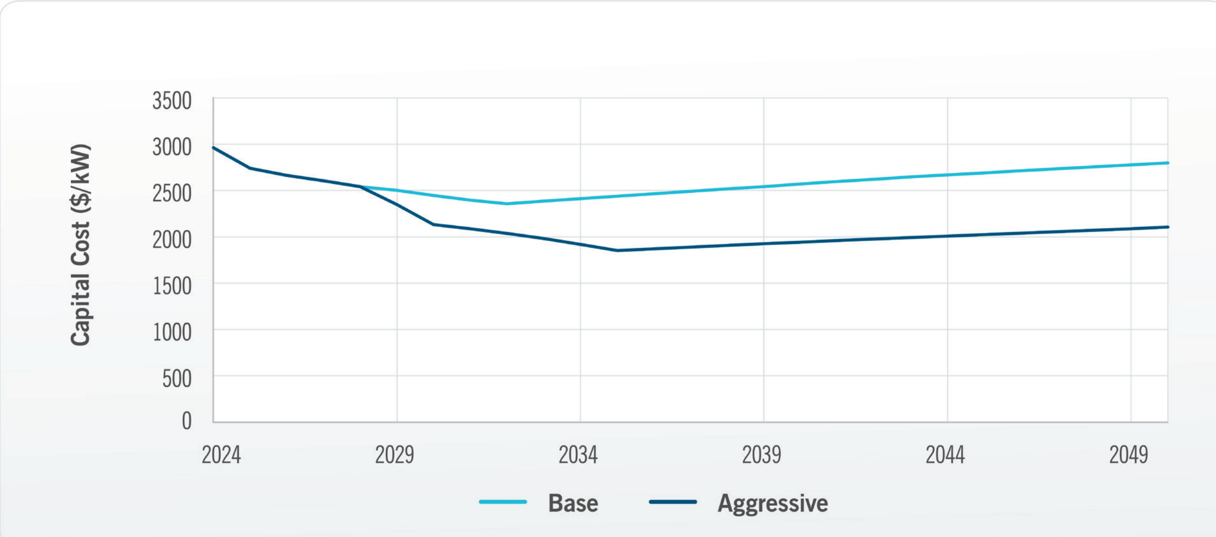


Figure C-17: Capital Cost Forecasts for Solar Paired with Storage



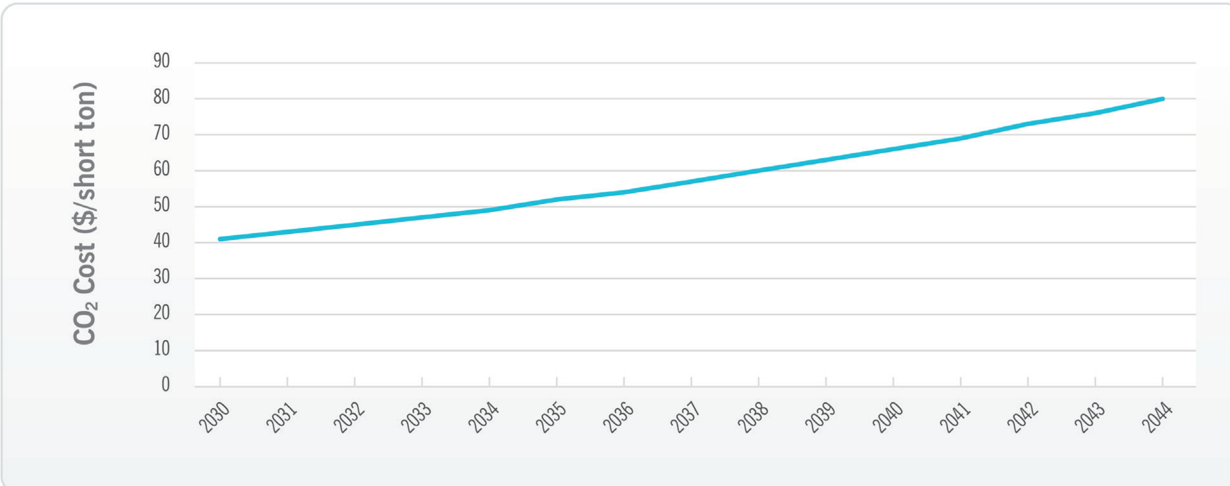
Distributed Energy Resources

The Company assumed that customer adoption of distributed energy resources would accelerate in the Aggressive Worldview and decelerate in the Minimum Worldview. The alternate forecasts for distributed energy resource adoption, which are described in detail in Appendix D, result in changes to the net load forecast for the alternate planning scenarios. The base economic load forecast does not change across worldviews, but the differing impacts from distributed energy resources lead to differences in net load, including differences in time of peak. Differences in time of peak affect the contribution to peak (capacity value) of energy efficiency programs.

Carbon Tax

The Aggressive Worldview includes a tax on CO_2 emissions from power generation beginning in 2030. The CO_2 tax assumption is informed by the Market Choice Act reintroduced in the 118th Congress, which proposed a tax of $35 per metric ton of CO_2 equivalent emissions, beginning in 2025. For the Aggressive Worldview, the Company assumes a tax on CO_2 emissions of $40.52/short ton is imposed starting in 2030 and escalating at 5% per year thereafter. Figure C-18 below provides the CO_2 tax forecast for the Aggressive Worldview.

Figure C-18: Annual CO_2 Tax in Aggressive Worldview



Strategy Variations

The Company evaluated several variations on the generation strategies described in Chapter 2. These strategy variations explore the potential impacts of changing certain key assumptions and resource decisions. Most notably, the Company evaluated a case in which it fully reoptimized a resource portfolio for a future in which the EPA CAA Section 111 Rule is rolled back, but all other Reference scenario assumptions hold. In this case, the Company would not pursue co-firing or full natural gas conversion at any of its coal units, and there would be no capacity factor limitation on new natural gas resources. The retirement dates for existing coal units under this variation are provided in Figure C-14 above.

In addition to the "No 111" strategy variation, the Company evaluated several alternate, prescribed resource changes using the Blend 2 portfolio as a base case. For each of these Blend 2 variations, the Company reoptimized resource selection around the prescribed change(s) using the capacity expansion model and conducted detailed production cost modeling for each resulting portfolio. The Blend 2 variations, described below, are also discussed in Chapter 2 and Chapter 5.

2x1 CC in Place of 1x1 CCs

The Preferred Portfolio includes two 1x1 CCs to replace the retiring Cayuga coal units. This variation evaluates the pros and cons of replacing the Cayuga units with a single 2x1 CC rather than two 1x1 machines. In this case, the retirement of the Cayuga units could no longer be staggered, and both would retire by the end of 2031 when the 2x1 CC could be brought online. The 2x1 CC is somewhat less costly than two 1x1 CCs, but does not provide the reliability, operational flexibility, and plan executability benefits offered by the two separate machines.

Natural Gas Conversion in Place of Co-firing for Gibson 1 & 2

The Preferred Portfolio calls for co-firing Gibson units 1 and 2 on a blend of coal and gas starting in 2030. This variation evaluates the pros and cons of converting those units to 100% natural gas. Full natural gas conversion is somewhat more costly than the modifications required to co-fire the units, but fully natural gas-fired steam units are not required to retire by the end of 2038 under the EPA CAA Section 111 Rule and would instead be able to continue to provide capacity through the end of the planning period.

Add Small Modular Reactors

Because the Preferred Portfolio does not include new nuclear resources, the Company evaluated a variation in which it added one 300 MW SMR to the portfolio in 2037 and another in 2038. This allowed the Company to assess the impact of SMRs on PVRR, resource selection, and portfolio operations.

Edwardsport Carbon Capture & Sequestration

Edwardsport IGCC is converted to natural gas fuel by 2030 in the Preferred Portfolio. In this variation, the Company evaluated the potential changes that could occur if the unit were to be retrofitted with carbon capture and sequestration equipment by 2032, allowing it to continue to gasify coal in compliance with the EPA CAA Section 111 Rule. If CCS could be implemented at Edwardsport, the unit would qualify to earn tax 45Q credits over a 12-year period based on the volume of CO_2 sequestered. Edwardsport is the only facility in the Company's fleet with the potential to deploy CCS by the 2032 deadline under the EPA CAA Section 111 Rule.

Edwardsport Conversion by 2028

In addition to CCS, the Company also evaluated the potential cost changes that could occur if it converted Edwardsport IGCC to 100% natural gas fuel by 2028 instead of by 2030.

Blend 2 with No 111 Variation (Production Cost)

In addition to the fully reoptimized "No 111" and the Blend 2 variations described above, the Company conducted a production cost model run (without any changes to the resource mix) for the Preferred Portfolio (Blend 2) assuming that the EPA CAA Section 111 Rule does not survive legal challenges or is otherwise rolled back.

Sensitivity Analysis

Sensitivity analysis is used to assess the relative robustness of analytical results to changes in specific inputs. In this analysis, a single variable is stressed while all other inputs and assumptions are held constant, isolating the impacts of the variable being tested. Sensitivity analysis for the 2024 IRP is discussed in Chapter 4 (Candidate Resource Portfolios), with additional detail provided in this Appendix. The Company performed portfolio sensitivity analysis to evaluating resource selection impacts for the following key variables.

- CC and CT capital costs (60% higher than base forecast)
- Load forecast (high and low)
- Resource accreditation (using SAC construct through the full 20-year planning period)

In addition to portfolio sensitivity analysis on the variables listed above, the Company conducted production cost sensitivity analysis using high and low fuel price forecasts and the associated power price forecasts.

Results of Capacity Expansion Modeling

This section provides the installed capacity by resource type for each of the portfolios constructed in the 2024 IRP. These resource mixes are the outputs of the capacity expansion model. The tables below show results for the 18 portfolios associated with the generation strategies (portfolios for each of the six strategies in each of the three planning scenarios), the “No 111” strategy variation, the five variations on the Preferred Portfolio, and five sensitivity analysis portfolios. In the results tables below, Edwardsport is included in the CC category after it is optimized to run solely on natural gas fuel, and the CT category includes the diesel generators at Cayuga (10 MW capacity combined).

Generation Strategies: Reference Scenario

This section shows the capacity expansion plans for each of the generation strategies modeled in the Reference Scenario.

Convert/Co-fire Coal – Reference Scenario

Table C-30 below shows the installed capacity by year for the Convert/Co-fire Coal generation strategy in the Reference Scenario.

Table C-30: Installed Capacity by Resource Type for Convert/Co-fire in Reference Scenario (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	586	586	586	586	586	586	586	586	586	586
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar Photo-voltaic ("PV")	44	243	243	393	393	389	389	389	389	389	389	378	367	367	2,167	2,367	4,117	5,917	7,667	9,467
Wind	100	100	100	-	-	-	-	-	-	250	350	550	950	1,350	1,750	2,150	2,550	2,950	3,350	3,750
Battery Storage	15	15	15	365	365	465	465	465	465	465	765	765	765	765	1,665	1,715	1,715	1,715	1,715	2,065
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Retire Coal – Reference Scenario

Table C-31 below shows the installed capacity by year for the Retire Coal generation strategy in the Reference Scenario.

Table C-31: Installed Capacity by Resource Type for Retire Coal in Reference Scenario (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	4,493	4,493	4,493	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	443	443	439	439	439	439	439	439	428	417	417	417	417	1,917	3,517	5,317	7,117
Wind	100	100	100	-	-	-	-	-	250	500	900	1,300	1,700	2,100	2,500	2,900	3,300	3,700	4,100	4,500
Battery Storage	15	15	15	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315	315
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 1 – Reference Scenario

Table C-32 below shows the installed capacity by year for the Blend 1 generation strategy in the Reference Scenario.

Table C-32: Installed Capacity by Resource Type for Blend 1 in Reference Scenario (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,526	2,526	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	443	443	439	439	439	439	439	439	428	417	417	417	417	2,217	4,017	5,817	7,617
Wind	100	100	100	-	-	-	-	-	-	-	-	-	250	650	1,050	1,450	1,850	2,250	2,650	3,050
Battery Storage	15	15	15	315	315	415	415	415	415	415	415	415	415	415	415	415	415	415	415	415
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 2 – Reference Scenario

Table C-33 below shows the installed capacity by year for the Blend 2 generation strategy in the Reference Scenario. Blend 2 in the Reference Scenario is the Preferred Portfolio.

Table C-33: Installed Capacity by Resource Type for Blend 2 in Reference Scenario (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	539	539	539	539	539	539	528	517	517	1,667	1,817	3,517	5,267	7,067	8,867
Wind	100	100	100	-	-	-	-	-	-	-	-	400	800	1,200	1,600	2,000	2,400	2,800	3,200	3,600
Battery Storage	15	15	15	365	365	415	415	415	415	415	415	415	415	415	965	990	990	990	990	990
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 4 – Reference Scenario

Table C-34 below shows the installed capacity by year for the Blend 4 generation strategy in the Reference Scenario.

Table C-34: Installed Capacity by Resource Type for Blend 4 in Reference Scenario (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	240	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	489	489	489	489	489	489	478	467	467	2,167	2,217	4,017	5,517	7,267	9,067
Wind	100	100	100	-	-	-	-	-	-	-	-	400	800	1,200	1,600	2,000	2,400	2,800	3,200	3,600
Battery Storage	15	15	15	365	365	440	440	440	440	440	440	440	440	440	1,290	1,315	1,315	1,315	1,315	1,315
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Exit Coal Earlier (Stakeholder) – Reference Scenario

Table C-35 below shows the installed capacity by year for the Exit Coal Earlier (Stakeholder) generation strategy in the Reference Scenario.

Table C-35: Installed Capacity by Resource Type for Exit Coal Earlier (Stakeholder) in Reference Scenario (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	2,839	1,266	1,266	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	3,055	3,055	3,055	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	589	589	589	589	589	589	578	567	567	567	567	2,367	4,167	5,967	7,767
Wind	100	100	100	-	-	-	-	-	-	-	350	750	1,150	1,550	1,950	2,350	2,750	3,150	3,550	3,950
Battery Storage	15	15	15	340	340	690	690	690	690	690	690	690	690	690	690	690	690	690	690	1,590
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Generation Strategies: Aggressive Policy & Rapid Innovation Worldview

This section shows the capacity expansion plans for each of the generation strategies modeled in the Aggressive Policy & Rapid Innovation Worldview.

Convert/Co-fire Coal – Aggressive Worldview

Table C-36 below shows the installed capacity by year for the Convert/Co-fire Coal generation strategy in the Aggressive Worldview.

Table C-36: Installed Capacity by Resource Type for Convert/Co-fire Coal in Aggressive Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	586	586	586	586	586	586	586	586	586	586
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	339	339	339	339	339	2,839	4,928	5,367	5,817	6,217	6,317	6,817	6,967	7,117	7,867
Wind	100	100	100	200	400	1,000	1,600	2,600	3,600	4,600	4,850	4,850	5,050	5,100	6,000	6,000	6,900	6,950	6,950	7,350
Battery Storage	15	15	15	365	365	465	465	465	465	465	590	590	590	1,090	1,615	1,715	1,715	1,815	1,915	2,415
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Retire Coal – Aggressive Worldview

Table C-37 below shows the installed capacity by year for the Retire Coal generation strategy in the Aggressive Worldview.

Table C-37: Installed Capacity by Resource Type for Retire Coal in Aggressive Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	293	393	443	439	439	1,739	1,739	1,739	4,239	4,428	4,617	4,767	4,767	4,767	7,067	7,067	7,217	7,367
Wind	100	100	100	200	400	1,000	1,600	2,600	3,600	4,050	4,050	4,050	4,050	4,050	4,650	5,400	6,400	6,850	6,850	7,100
Battery Storage	15	15	15	340	340	490	490	1,790	1,790	1,790	2,065	2,165	2,165	2,165	2,165	2,215	2,215	2,265	2,365	2,365
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 1 – Aggressive Worldview

Table C-38 below shows the installed capacity by year for the Blend 1 generation strategy in the Aggressive Worldview.

Table C-38: Installed Capacity by Resource Type for Blend 1 in Aggressive Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,526	2,526	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	389	389	389	389	389	2,589	4,628	4,617	4,617	4,617	4,617	6,217	6,217	6,217	6,967
Wind	100	100	100	200	400	1,000	1,600	2,600	3,600	4,450	4,450	4,450	4,450	4,450	5,000	5,700	6,700	7,000	7,000	7,250
Battery Storage	15	15	15	340	340	440	440	940	940	940	1,190	1,190	1,240	1,240	1,290	1,340	1,340	1,390	1,490	1,990
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 2 – Aggressive Worldview

Table C-39 below shows the installed capacity by year for the Blend 2 generation strategy in the Aggressive Worldview.

Table C-39: Installed Capacity by Resource Type for Blend 2 in Aggressive Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	389	389	389	389	389	2,889	4,428	4,617	4,817	4,967	5,067	7,317	7,317	7,317	7,717
Wind	100	100	100	200	400	1,000	1,600	2,600	3,600	4,100	4,100	4,100	4,100	4,100	5,100	5,500	6,500	6,800	6,950	7,100
Battery Storage	15	15	15	340	340	440	440	840	840	840	1,140	1,140	1,140	1,640	2,140	2,240	2,240	2,240	2,340	2,440
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 4 – Aggressive Worldview

Table C-40 below shows the installed capacity by year for the Blend 4 generation strategy in the Aggressive Worldview.

Table C-40: Installed Capacity by Resource Type for Blend 4 in Aggressive Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	240	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	339	339	339	339	339	2,839	4,178	4,417	4,667	4,717	4,717	6,267	6,267	6,517	7,317
Wind	100	100	100	200	400	1,000	1,600	2,600	3,550	4,050	4,050	4,050	4,050	4,050	5,050	5,450	6,450	6,750	6,800	7,000
Battery Storage	15	15	15	365	365	465	465	465	465	465	465	465	465	765	1,265	1,365	1,365	1,365	1,465	1,965
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Exit Coal Earlier (Stakeholder) – Aggressive Worldview

Table C-41 below shows the installed capacity by year for the Exit Coal Earlier (Stakeholder) generation strategy in the Aggressive Worldview.

Table C-41: Installed Capacity by Resource Type for Exit Coal Earlier (Stakeholder) in Aggressive Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	2,839	1,266	1,266	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	1,617	1,617	1,617	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	389	389	389	389	439	2,939	4,928	5,317	5,317	5,317	5,367	6,967	6,967	7,517	8,167
Wind	100	100	100	200	400	1,000	1,600	2,600	3,600	4,550	4,550	4,550	4,550	4,550	5,400	5,800	6,800	7,100	7,150	7,550
Battery Storage	15	15	15	340	340	840	840	1,640	1,640	1,690	1,890	1,890	1,890	1,890	1,940	2,040	2,040	2,040	2,540	3,040
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	700	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Generation Strategies: Minimum Policy & Lagging Innovation Worldview

This section shows the capacity expansion plans for each of the generation strategies modeled in the Minimum Policy & Lagging Innovation Worldview.

Convert/Co-fire Coal – Minimum Worldview

Table C-42 below shows the installed capacity by year for the Convert/Co-fire Coal generation strategy in the Minimum Worldview.

Table C-42: Installed Capacity by Resource Type for Convert/Co-fire Coal in Minimum Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	439	439	439	439	439	439	428	417	417	417	417	417	467	467	617
Wind	100	100	100	-	-	-	-	-	50	50	50	50	50	50	50	50	50	50	50	100
Battery Storage	15	15	15	390	390	465	465	465	465	515	515	515	515	615	1,315	1,365	1,415	1,465	1,515	1,565
EE	46	67	99	126	156	192	221	248	274	305	327	346	366	382	394	400	408	425	432	435
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	920	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Retire Coal – Minimum Worldview

Table C-43 below shows the installed capacity by year for the Retire Coal generation strategy in the Minimum Worldview.

Table C-43: Installed Capacity by Resource Type for Retire Coal in Minimum Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	4,493	4,493	4,493	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	389	389	389	389	389	389	378	367	367	367	367	367	367	367	367
Wind	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	15	15	15	390	390	390	390	390	390	390	390	440	540	590	640	740	740	840	890	940
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	920	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 1 – Minimum Worldview

Table C-44 below shows the installed capacity by year for the Blend 1 generation strategy in the Minimum Worldview.

Table C-44: Installed Capacity by Resource Type for Blend 1 in Minimum Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,526	2,526	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	389	389	389	389	389	389	378	367	367	367	367	367	367	367	367
Wind	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	15	15	15	390	390	490	490	490	490	490	490	490	490	490	490	540	590	590	640	890
EE	46	67	99	126	155	192	221	248	274	299	313	323	335	344	349	348	349	364	373	377
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	920	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 2 – Minimum Worldview

Table C-45 below shows the installed capacity by year for the Blend 2 generation strategy in the Minimum Worldview.

Table C-45: Installed Capacity by Resource Type for Blend 2 in Minimum Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	5,212	5,212	5,212	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	389	389	389	389	389	389	378	367	367	367	367	367	367	367	367
Wind	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	15	15	15	390	390	490	490	490	490	490	490	490	490	490	490	490	490	490	490	490
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	920	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 4 – Minimum Worldview

Table C-46 below shows the installed capacity by year for the Blend 4 generation strategy in the Minimum Worldview.

Table C-46: Installed Capacity by Resource Type for Blend 4 in Minimum Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	240	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	389	389	389	389	389	389	378	367	367	367	367	367	367	417	417
Wind	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	15	15	15	390	390	490	490	490	490	490	490	490	490	490	490	490	490	540	615	865
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	920	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Exit Coal Earlier (Stakeholder) – Minimum Worldview

Table C-47 below shows the installed capacity by year for the Exit Coal Earlier (Stakeholder) generation strategy in the Minimum Worldview.

Table C-47: Installed Capacity by Resource Type for Exit Coal Earlier (Stakeholder) in Minimum Worldview (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	2,839	1,266	1,266	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	4,493	4,493	4,493	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	439	439	439	439	439	439	428	417	417	417	417	417	417	417	417
Wind	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery Storage	15	15	15	390	390	740	740	740	740	740	740	740	740	740	740	740	740	740	740	940
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	920	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Strategy Variations: Reference Scenario

This section shows the capacity expansion plans for each of the strategy variations modeled in the Reference Scenario.

Strategy Variation – "No 111"

Table C-48 below shows the installed capacity by year for the "No 111" strategy variation. The "No 111" case considers a future in which the EPA CAA Section 111 Rule does not persist, but Reference Scenario forecasts and assumptions otherwise hold.

Table C-48: Installed Capacity by Resource Type for "No 111" Strategy Variation (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	1,266	1,266	1,266	1,266	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	312	1,031	3,907	3,907	3,907	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	339	339	339	339	339	339	328	317	317	317	317	317	317	317	317
Wind	100	100	100	-	-	-	-	-	-	-	-	-	-	-	400	800	1,200	1,600	2,000	2,400
Battery Storage	15	15	15	365	365	515	515	515	515	515	515	515	515	565	565	565	565	565	565	565
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Strategy Variation – Cayuga 2x1 CC in place of 1x1 CCs

Table C-49 below shows the installed capacity by year for the Cayuga 2x1 CC variation on the Blend 2 generation strategy in the Reference Scenario.

Table C-49: Installed Capacity by Resource Type for Cayuga 2x1 CC Strategy Variation (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,258	2,258	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	443	443	539	539	539	539	539	539	528	517	517	1,567	1,617	3,417	4,667	6,467	8,267
Wind	100	100	100	-	-	-	-	-	-	-	50	450	850	1,250	1,650	2,050	2,450	2,850	3,250	3,650
Battery Storage	15	15	15	365	365	415	415	415	415	415	415	415	415	415	915	940	940	940	940	940
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Strategy Variation – Gibson 1 & 2 Natural Gas Conversion in place of Co-firing

Table C-50 below shows the installed capacity by year for the Gibson 1 and 2 Natural Gas Conversion variation on the Blend 2 generation strategy in the Reference Scenario.

Table C-50: Installed Capacity by Resource Type for Gibson 1 & 2 Natural Gas Conversion Strategy Variation (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,766	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	539	539	539	539	539	539	528	517	517	517	517	2,317	4,117	5,867	7,667
Wind	100	100	100	-	-	-	-	-	-	-	-	-	400	800	1,200	1,600	2,000	2,400	2,800	3,200
Battery Storage	15	15	15	340	340	415	415	415	415	415	415	415	415	415	415	415	415	415	415	415
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Strategy Variation – Add Small Modular Reactors

Table C-51 below shows the installed capacity by year for the Add SMRs variation on the Blend 2 generation strategy in the Reference Scenario.

Table C-51: Installed Capacity by Resource Type for Add SMRs Strategy Variation (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
SMR	-	-	-	-	-	-	-	-	-	-	-	-	300	600	600	600	600	600	600	600
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	489	489	489	489	489	489	478	467	467	517	567	1,717	3,517	5,317	7,117
Wind	100	100	100	-	-	-	-	-	-	-	-	200	500	900	1,300	1,700	2,100	2,500	2,900	3,300
Battery Storage	15	15	15	340	340	440	440	440	440	440	440	440	440	440	465	465	465	465	465	465
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Strategy Variation – Edwardsport Carbon Capture & Sequestration

Table C-52 below shows the installed capacity by year for the Edwardsport CCS variation on the Blend 2 generation strategy in the Reference Scenario.

Table C-52: Installed Capacity by Resource Type for Edwardsport CCS Variation (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC w/ CCS	-	-	-	-	-	-	-	491	491	491	491	491	491	491	491	491	491	491	491	491
CC	312	312	312	312	312	1,031	1,750	3,188	3,188	3,188	2,876	2,876	2,876	2,876	2,876	2,876	2,876	2,876	2,876	2,876
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	439	439	439	439	439	439	428	417	417	1,567	1,567	3,367	4,617	6,417	8,217
Wind	100	100	100	-	-	-	-	-	-	-	300	700	1,100	1,500	1,900	2,300	2,700	3,100	3,500	3,900
Battery Storage	15	15	15	365	365	490	490	490	490	490	490	490	490	490	1,065	1,065	1,065	1,065	1,065	1,065
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Strategy Variation – Edwardsport Natural Gas Conversion by 2028

Table C-53 below shows the installed capacity by year for the Edwardsport natural gas conversion by 2028 variation on the Blend 2 generation strategy in the Reference Scenario.

Table C-53: Installed Capacity by Resource Type for Edwardsport Natural Gas Conversion by 2028 Strategy Variation (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	898	898	1,617	2,336	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	589	589	589	589	589	589	578	567	567	1,817	1,867	3,317	5,117	6,917	8,617
Wind	100	100	100	-	-	-	-	-	-	-	-	400	800	1,200	1,600	2,000	2,400	2,800	3,200	3,600
Battery Storage	15	15	15	315	315	390	390	390	390	390	390	390	390	390	940	965	965	965	965	990
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Portfolio Sensitivity Analysis: High Combined Cycle/Combustion Turbine Costs

This section shows the capacity expansion plans for each of the generation strategies modeled in the Reference Scenario assuming high CC and CT capital costs (60% higher than the base cost forecast).

Convert/Co-fire Coal with High CC/CT Costs

Table C-54 below shows the installed capacity by year for the Convert/Co-fire Coal strategy in the Reference Scenario with high CC and CT costs.

Table C-54: Installed Capacity by Resource Type for Convert/Co-fire Coal in Reference Scenario with High CC/CT Costs (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	586	586	586	586	586	586	586	586	586	586
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	339	339	339	339	339	339	328	317	317	2,117	2,317	4,117	5,917	7,667	9,467
Wind	100	100	100	-	-	-	-	-	-	-	50	450	600	1,000	1,400	1,800	2,200	2,600	3,000	3,400
Battery Storage	15	15	15	365	365	465	465	465	465	515	815	815	815	815	1,715	1,765	1,765	1,765	1,765	2,090
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Retire Coal with High CC/CT Costs

Table C-55 below shows the installed capacity by year for the Retire Coal strategy in the Reference Scenario with high CC and CT costs.

Table C-55: Installed Capacity by Resource Type for Retire Coal in Reference Scenario with High CC/CT Costs (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	489	489	639	639	639	989	978	967	967	967	1,067	2,867	4,667	5,967	7,767
Wind	100	100	100	-	-	-	250	650	900	1,300	1,700	2,100	2,500	2,900	3,300	3,700	4,100	4,500	4,900	5,300
Battery Storage	15	15	15	365	365	415	415	490	490	490	665	715	715	715	715	765	765	765	790	865
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 1 with High CC/CT Costs

Table C-56 below shows the installed capacity by year for the Blend 1 strategy in the Reference Scenario with high CC and CT costs.

Table C-56: Installed Capacity by Resource Type for Blend 1 in Reference Scenario with High CC/CT Costs (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,526	2,526	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	339	339	889	889	889	989	978	967	967	967	967	2,767	4,567	6,367	8,167
Wind	100	100	100	-	-	-	-	-	-	150	550	950	1,350	1,750	2,150	2,550	2,950	3,350	3,750	4,150
Battery Storage	15	15	15	365	365	465	465	990	990	1,040	1,240	1,290	1,290	1,290	1,290	1,290	1,290	1,290	1,340	1,390
EE	46	67	99	126	156	192	221	249	275	305	327	345	366	382	394	400	408	420	420	415
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 2 with High CC/CT Costs

Table C-57 below shows the installed capacity by year for the Blend 2 strategy in the Reference Scenario with high CC and CT costs.

Table C-57: Installed Capacity by Resource Type for Blend 2 in Reference Scenario with High CC/CT Costs (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	393	393	489	739	739	739	739	739	728	717	717	2,517	2,867	4,667	6,467	8,267	10,067
Wind	100	100	100	-	-	-	150	150	150	350	750	1,150	1,550	1,950	2,350	2,750	3,150	3,550	3,950	4,350
Battery Storage	15	15	15	390	390	1,065	1,165	1,165	1,165	1,165	1,165	1,165	1,165	1,165	2,065	2,115	2,115	2,115	2,115	2,190
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 4 with High CC/CT Costs

Table C-58 below shows the installed capacity by year for the Blend 4 strategy in the Reference Scenario with high CC and CT costs.

Table C-58: Installed Capacity by Resource Type for Blend 4 in Reference Scenario with High CC/CT Costs (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	240	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	586	586	586	586	586	586	586	586	586	586
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	439	439	439	439	439	439	428	417	417	2,167	3,517	5,317	7,117	8,917	10,567
Wind	100	100	100	-	-	-	-	-	-	50	450	850	1,250	1,650	2,050	2,450	2,850	3,250	3,650	4,050
Battery Storage	15	15	15	365	415	1,115	1,315	1,315	1,315	1,415	1,615	1,615	1,615	1,615	2,490	2,490	2,490	2,490	2,515	2,565
EE	46	67	99	126	156	192	221	249	275	305	327	345	366	382	394	400	408	420	420	415
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Exit Coal Earlier (Stakeholder) with High CC/CT Costs

Table C-59 below shows the installed capacity by year for the Exit Coal Earlier (Stakeholder) strategy in the Reference Scenario with high CC and CT costs.

Table C-59: Installed Capacity by Resource Type for Exit Coal Earlier (Stakeholder) in Reference Scenario with High CC/CT Costs (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	2,839	1,266	1,266	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	443	443	939	939	939	939	939	939	928	917	917	917	1,067	2,867	4,667	6,267	8,067
Wind	100	100	100	-	-	-	-	-	-	400	750	1,150	1,550	1,950	2,350	2,750	3,150	3,550	3,950	4,350
Battery Storage	15	15	15	315	315	1,215	1,215	1,215	1,215	1,215	1,215	1,265	1,265	1,265	1,265	1,315	1,315	1,315	1,340	2,240
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Portfolio Sensitivity Analysis: High Load

This section shows the capacity expansion plans for each of the generation strategies modeled in the Reference Scenario assuming the high load forecast described in Appendix D and previously in this Appendix.

Convert/Co-fire Coal with High Load Forecast

Table C-60 below shows the installed capacity by year for the Convert/Co-fire Coal strategy in the Reference Scenario with the high load forecast.

Table C-60: Installed Capacity by Resource Type for Convert/Co-fire Coal in Reference Scenario with High Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	1,393	1,393	1,439	1,439	1,489	1,589	1,589	1,589	1,578	1,567	1,567	3,317	4,967	6,767	8,567	10,367	11,817
Wind	100	100	100	200	200	200	200	200	300	700	750	1,150	1,550	1,950	2,350	2,750	3,150	3,550	3,950	4,350
Battery Storage	15	15	15	890	1,190	1,390	1,590	1,665	1,665	1,665	1,665	1,665	1,665	1,665	2,540	2,540	2,540	2,540	2,615	3,065
EE	46	67	99	126	156	192	221	249	275	305	327	345	366	382	394	400	408	420	420	415
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	1,500	1,670	1,350	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Retire Coal with High Load Forecast

Table C-61 below shows the installed capacity by year for the Retire Coal strategy in the Reference Scenario with the high load forecast.

Table C-61: Installed Capacity by Resource Type for Retire Coal in Reference Scenario with High Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	5,212	5,212	5,212	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	1,393	1,543	1,539	1,539	2,389	2,389	2,389	2,389	2,378	2,367	2,367	2,367	2,367	4,167	5,917	7,567	9,367
Wind	100	100	100	200	400	600	900	1,300	1,550	1,950	2,350	2,750	3,150	3,550	3,950	4,350	4,750	5,150	5,550	5,950
Battery Storage	15	15	15	890	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,065	1,165	1,265
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	1,500	1,670	1,350	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 1 with High Load Forecast

Table C-62 below shows the installed capacity by year for the Blend 1 strategy in the Reference Scenario with the high load forecast.

Table C-62: Installed Capacity by Resource Type for Blend 1 in Reference Scenario with High Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,526	2,526	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	4,493	4,493	4,493	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	1,393	1,443	1,439	1,439	1,439	1,439	1,439	1,439	1,428	1,417	1,417	1,417	1,417	3,217	5,017	6,817	8,617
Wind	100	100	100	200	350	350	350	350	400	800	1,200	1,600	2,000	2,400	2,800	3,200	3,600	4,000	4,400	4,800
Battery Storage	15	15	15	890	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	1,500	1,670	1,350	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 2 with High Load Forecast

Table C-63 below shows the installed capacity by year for the Blend 2 strategy in the Reference Scenario with the high load forecast.

Table C-63: Installed Capacity by Resource Type for Blend 2 in Reference Scenario with High Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	5,212	5,212	5,212	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	1,393	1,393	1,539	1,539	1,539	1,539	1,539	1,539	1,528	1,517	1,517	3,317	3,567	5,367	7,167	8,917	10,717
Wind	100	100	100	100	100	100	100	100	100	250	300	700	1,100	1,500	1,900	2,300	2,700	3,100	3,500	3,900
Battery Storage	15	15	15	890	1,140	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,365
EE	46	67	105	139	178	213	241	268	293	318	331	341	352	360	364	364	364	371	369	362
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	1,500	1,670	1,350	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 4 with High Load Forecast

Table C-64 below shows the installed capacity by year for the Blend 4 strategy in the Reference Scenario with the high load forecast.

Table C-64: Installed Capacity by Resource Type for Blend 4 in Reference Scenario with High Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	240	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	293	1,443	1,493	1,589	1,589	1,589	1,589	1,589	1,589	1,578	1,567	1,567	2,317	3,667	5,467	7,267	9,067	10817
Wind	100	100	100	150	150	150	150	150	150	150	550	950	1,350	1,750	2,150	2,550	2,950	3,350	3,750	4,150
Battery Storage	15	15	15	890	1,140	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,315	1,590	1,590	1,590	1,590	1,690	1,690
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	364	373	377
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	1,500	1,670	1,350	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Exit Coal Earlier (Stakeholder) with High Load Forecast

Table C-65 below shows the installed capacity by year for the Exit Coal Earlier (Stakeholder) strategy in the Reference Scenario with the high load forecast.

Table C-65: Installed Capacity by Resource Type for Exit Coal Earlier (Stakeholder) in Reference Scenario with High Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	2,839	1,266	1,266	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	4,493	4,493	4,493	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181	4,181
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	993	993	1,389	1,589	1,589	1,589	1,589	1,589	1,578	1,567	1,567	1,567	1,567	3,267	5,067	6,867	8,167
Wind	100	100	100	-	200	500	750	750	750	1,150	1,550	1,950	2,350	2,750	3,150	3,550	3,950	4,350	4,750	5,150
Battery Storage	15	15	15	1,090	1,240	1,490	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,590	1,915
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	364	373	377
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	1,500	1,670	1,350	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Portfolio Sensitivity Analysis: Low Load

This section shows the capacity expansion plans for each of the generation strategies modeled in the Reference Scenario assuming the low load forecast described in Appendix D and previously in this Appendix.

Convert/Co-fire Coal with Low Load Forecast

Table C-66 below shows the installed capacity by year for the Convert/Co-fire Coal strategy in the Reference Scenario with the low load forecast.

Table C-66: Installed Capacity by Resource Type for Convert/Co-fire Coal in Reference Scenario with Low Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	586	586	586	586	586	586	586	586	586	586
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	243	243	239	239	239	239	239	239	228	217	217	1,867	1,867	3,667	5,417	7,217	9,017
Wind	100	100	100	-	-	-	-	-	-	-	400	500	900	1,300	1,700	2,100	2,500	2,900	3,300	3,700
Battery Storage	15	15	15	165	165	265	265	265	265	265	365	365	365	365	1,190	1,190	1,190	1,190	1,190	1,240
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	364	373	377
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	650	570	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Retire Coal with Low Load Forecast

Table C-67 below shows the installed capacity by year for the Retire Coal strategy in the Reference Scenario with the low load forecast.

Table C-67: Installed Capacity by Resource Type for Retire Coal in Reference Scenario with Low Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	489	489	739	739	739	939	928	917	967	967	967	1,817	3,117	4,917	6,717
Wind	100	100	100	-	-	-	-	150	150	500	900	1,200	1,600	2,000	2,400	2,800	3,200	3,600	4,000	4,400
Battery Storage	15	15	15	115	115	190	190	215	215	215	315	315	315	340	340	340	340	340	340	340
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	650	570	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 1 with Low Load Forecast

Table C-68 below shows the installed capacity by year for the Blend 1 strategy in the Reference Scenario with the low load forecast.

Table C-68: Installed Capacity by Resource Type for Blend 1 in Reference Scenario with Low Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	2,526	2,526	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	1,617	3,055	3,055	3,055	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	243	243	289	289	289	289	289	289	278	267	267	267	267	2,067	3,817	5,617	7,417
Wind	100	100	100	-	-	-	-	-	-	250	650	750	750	900	1,300	1,700	2,100	2,500	2,900	3,300
Battery Storage	15	15	15	165	165	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	650	570	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 2 with Low Load Forecast

Table C-69 below shows the installed capacity by year for the Blend 2 strategy in the Reference Scenario with the low load forecast.

Table C-69: Installed Capacity by Resource Type for Blend 2 in Reference Scenario with Low Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	1,500	1,261	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	293	293	339	339	339	339	339	339	328	317	317	817	817	2,367	3,017	4,817	6,617
Wind	100	100	100	-	-	-	-	-	-	-	-	-	400	800	1,200	1,600	2,000	2,400	2,800	3,200
Battery Storage	15	15	15	115	115	215	215	215	215	215	215	215	215	215	415	415	415	415	415	415
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	650	570	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Blend 4 with Low Load Forecast

Table C-70 below shows the installed capacity by year for the Blend 4 strategy in the Reference Scenario with the low load forecast.

Table C-70: Installed Capacity by Resource Type for Blend 4 in Reference Scenario with Low Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	240	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	2,336	2,336	2,336	2,336	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024	2,024
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	343	343	489	489	489	489	489	489	478	467	467	1,617	1,617	3,417	4,417	6,117	7,917
Wind	100	100	100	-	-	-	-	-	-	-	-	400	700	1,100	1,500	1,900	2,300	2,700	3,100	3,500
Battery Storage	15	15	15	115	115	190	190	190	190	190	190	190	190	190	765	765	765	765	765	765
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	650	570	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Exit Coal Earlier (Stakeholder) with Low Load Forecast

Table C-71 below shows the installed capacity by year for the Exit Coal Earlier (Stakeholder) strategy in the Reference Scenario with the low load forecast.

Table C-71: Installed Capacity by Resource Type for Exit Coal Earlier (Stakeholder) in Reference Scenario with Low Load Forecast (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	2,839	1,266	1,266	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	998	998	998	998	998	998	998	998	998	998	998	998	998	998	998	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	1,617	1,617	3,055	3,055	3,055	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743	2,743
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	443	443	443	589	589	589	589	589	589	578	567	567	567	567	2,367	4,167	5,967	7,767
Wind	100	100	100	-	-	-	-	-	-	-	100	250	300	700	1,100	1,500	1,900	2,300	2,700	3,100
Battery Storage	15	15	15	65	65	290	290	290	290	290	290	290	290	290	290	290	290	290	290	865
EE	46	67	105	139	178	213	241	268	293	318	331	341	352	360	364	364	364	376	381	382
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	650	570	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Portfolio Sensitivity Analysis: Seasonal Accredited Capacity Through 2044

This section shows the capacity expansion plans for the "bookend" generation strategies, Convert/Co-fire Coal and Retire Coal, in the Reference Scenario using the SAC resource accreditation construct throughout the planning period. As explained previously in this Appendix and in Chapter 3, the base assumption for the 2024 IRP is that MISO's proposed DLOL method will be implemented starting in year 2028 of the planning period.

Convert/Co-fire Coal with SAC Accreditation Through 2044

Table C-72 below shows the installed capacity by year for the Convert/Co-fire Coal strategy in the Reference Scenario using the SAC construct throughout the planning period.

Table C-72: Installed Capacity by Resource Type for Convert/Co-fire Coal in Reference Scenario with SAC Accreditation Throughout Planning Period (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	1,266	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	898	898	898	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	1,093	1,093	1,089	1,089	1,089	1,089	1,089	1,089	1,078	1,067	1,067	2,617	2,817	4,617	6,067	7,867	9,667
Wind	100	100	100	150	150	250	250	250	550	850	850	1,250	1,650	2,050	2,450	2,850	3,250	3,650	4,050	4,450
Battery Storage	15	15	15	740	790	790	790	840	840	840	840	840	840	840	1,315	1,315	1,315	1,315	1,315	1,315
EE	46	67	99	126	156	192	221	249	275	300	313	323	336	344	349	348	349	360	361	358
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Retire Coal with SAC Accreditation Through 2044

Table C-73 below shows the installed capacity by year for the Retire Coal strategy in the Reference Scenario using the SAC construct throughout the planning period.

Table C-73: Installed Capacity by Resource Type for Retire Coal in Reference Scenario with SAC Accreditation Throughout Planning Period (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal to Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	898	3,774	3,774	3,774	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462	3,462
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	1,043	1,043	1,039	1,039	1,039	1,039	1,039	1,039	1,028	1,017	1,017	1,067	1,217	1,967	3,567	5,367	7,167
Wind	100	100	100	200	200	200	200	600	1,000	1,400	1,800	2,200	2,600	3,000	3,400	3,800	4,200	4,600	5,000	5,400
Battery Storage	15	15	15	715	715	815	815	865	865	865	865	865	865	865	865	865	865	865	865	865
EE	46	67	105	139	178	213	241	268	293	318	331	341	352	360	364	364	364	371	369	362
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	850	870	750	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Deep Decarbonization & Rapid Electrification (Stakeholder)

At the request of certain stakeholders, the Company also evaluated a Deep Decarbonization and Rapid Electrification ("DDRE") case. This is a scenario in which the electrification of the economy proceeds at a much more rapid pace than in any of the Company's own projections, including the high load forecast. At the same time, in this stakeholder-defined case, the Company would make the unilateral decision to adhere to a self-imposed cap on CO_2 emissions, ultimately achieving net-zero emissions by 2050. The cap was specified by the stakeholders requesting the DDRE analysis, who explained that "the cap is intended to be modeled after the emissions reductions expected to be necessary to limit average global temperature increase to 1.5 degrees Celsius, consistent with the Paris Agreement treaty on climate change."

The fuel price and resource cost forecasts used for this case were consistent with the Company's assumptions for the Aggressive Policy & Rapid Innovation Worldview. The schedule for coal retirements and Edwardsport natural gas conversion from the Retire Coal generation strategy was used in the DDRE analysis.

Resource availability constraints were relaxed for this case to allow the model to solve for the extremely high projected load while simultaneously pursuing aggressive CO_2 emissions reduction. Similarly, the annual limit on market energy purchases that the Company imposed in capacity expansion modeling for other cases was removed. At stakeholders' direction, SMRs were not a selectable resource option for this case. The DDRE analysis was performed using the capacity expansion model only. Table C-74 below provides the target CO_2 cap for the DDRE case.

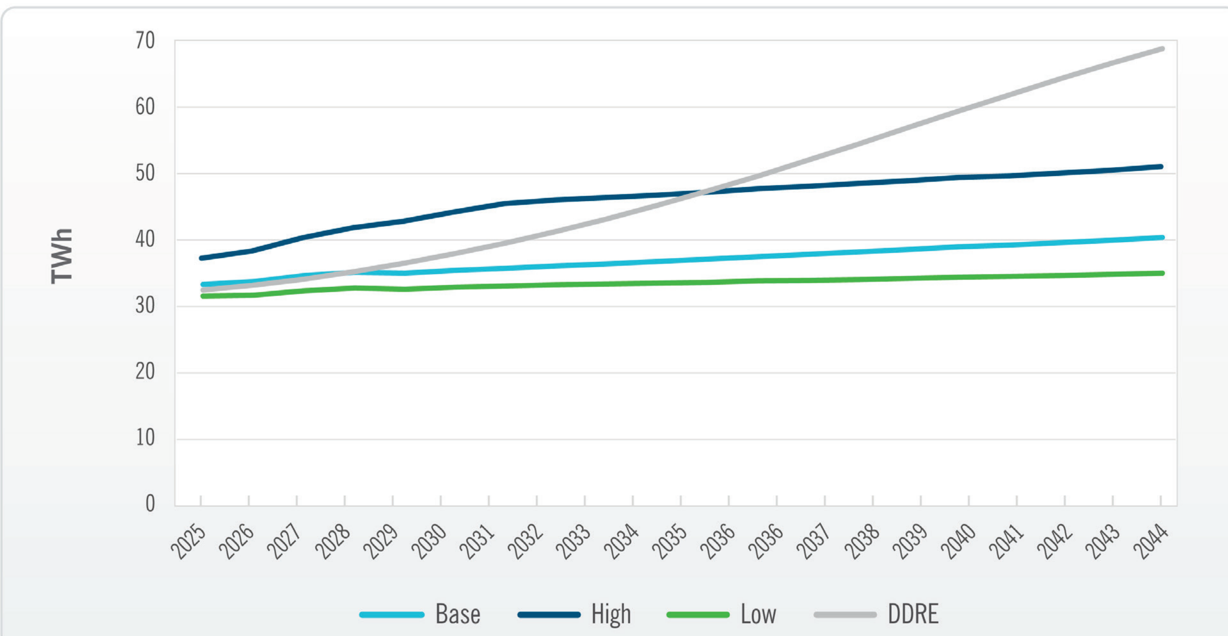
Table C-74: DDRE Carbon Mass Cap (Million Short Tons)

Year	Target CO_2 Cap
2025	22.0
2026	21.0
2027	18.5
2028	16.0
2029	13.5
2030	6.9
2031	5.8
2032	5.0
2033	4.2
2034	3.6
2035	3.1
2036	2.6
2037	2.2
2038	1.9

2039	1.6
2040	1.4
2041	1.4
2042	1.4
2043	1.4
2044	1.4

Figure C-19 below illustrates the annual energy requirements for the DDRE load forecast in the context of the base, high, and low load forecasts used in the 2024 IRP.

Figure C-19: Total Annual Energy for DDRE Load Forecast Compared to Base, High, and Low 2024 IRP Load Forecasts



Tables C-75 through C-77 below provides the resource availability assumptions used in the DDRE case. Per stakeholder recommendations, the Company did not model advanced nuclear reactors in this case.

Table C-75: Natural Gas Resource Availability for DDRE Case (MW)

Selection Year	CT	1x1 CC	2x1 CC	2x1 CC with CCS
2030-2031	850/yr	719/yr	–	–
2032	850	719	2,876	–
2033-2034	850/yr	2,157/yr	–	–
2035-2037	850/yr	2,157/yr	–	1,215/yr
2038+		–	–	1,215/yr

Table C-76: Renewable Resource Availability for DDRE Case (MW)

Selection Year	Solar	Paired Storage	Wind
2027	1,000	500	–
2028	2,000	1,000	1,000
2029	3,000	1,500	1,000
2030-2031	3,000/yr	1,500/yr	1,500/yr
2032+	3,000/yr	1,500/yr	2,000/yr

Table C-77: Standalone Energy Storage Resource Availability for DDRE Case (MW)

Selection Year	4-hour Li-ion	10-hour LDES	100-hour LDES
2025-2026	–	–	–
2027	300	–	–
2028-2029	400/yr	–	–
2030-2031	1,200/yr	500/yr	–
2032+	1,200/yr	500/yr	100/yr

Table C-80 below provides DDRE capacity expansion modeling results. As the results indicate, substantial amounts of renewable energy would be required to serve the significant energy needs in this case while aggressively reducing carbon emissions, and thousands of MW of energy storage, both 4-hour battery and long-duration, would be required to meet planning reserve margin requirements. Despite the aggressive carbon reduction targets, a 1x1 CC is added by 2031 to support system reliability.

Table C-78: Installed Capacity by Resource Type for DDRE Case (MW)

Resource Type	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Coal	3,837	3,837	3,837	3,837	3,837	3,524	3,524	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Converted (Coal-Gas)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC	568	568	568	568	568	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CC	312	312	312	312	312	898	1,617	1,617	1,617	1,617	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305
CT	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966	1,966
CHP	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Hydro	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	44	243	243	1,743	1,840	1,839	1,839	3,089	3,089	3,089	3,089	3,078	3,267	4,817	6,017	7,167	10,167	13,167	13,917	16,917
Wind	100	100	100	200	400	1,900	3,400	5,400	5,600	5,600	6,550	7,750	9,750	11,700	13,600	15,600	17,600	19,600	20,400	20,750
Battery Storage	15	15	65	1,215	1,665	1,765	2,065	4,390	4,690	5,190	5,690	5,990	6,390	6,640	7,040	7,340	7,640	8,040	8,440	8,740
EE	46	67	105	139	178	213	241	268	293	323	345	363	383	398	410	417	423	431	428	420
DR	526	525	531	536	540	542	545	548	551	554	557	560	563	567	570	573	576	579	582	585
IVVC	41	43	45	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Capacity Purchase	1,600	2,020	1,500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Results of Production Cost Modeling

The detailed production cost model is used to simulate sequential hourly dispatch over the planning period for each of the resource portfolios developed using the capacity expansion. The simulated characteristics of system operation are the outputs of the production cost model. These include system operating costs by resource (including fuel costs, variable operating and maintenance costs, unit start costs, and others), generation and run times by resource (including charging and discharging of storage), production tax credits by resource, economic energy market purchases and sales, emissions by resource (CO_2, SO_2, NO_x), and other factors.

The Company uses the results of the production cost runs to ensure that the portfolios developed in the capacity expansion model, which necessarily uses a very simplified version of system operations, to ensure that customer needs can be met in each hour of the planning period. In addition, these results provide the energy mix (including economic net market purchases) and CO_2 emissions data that are presented in Chapter 4.

Of particular importance, the production cost model provides the granular level of detail required to calculate PVRR and projected customer bill impacts.

Present Value of Revenue Requirements

PVRR is the standard resource planning metric used to estimate total cost to customers of a given portfolio over the 20-year planning period, including capital costs, fixed and variable operating costs, fuel costs, compliance costs, and so on. Importantly, PVRR is used to compare relative costs across the various portfolios evaluated in an IRP. Therefore, the calculation does not account for costs not related to resource planning, and it excludes unavoidable costs and costs that are assumed to be constant across all resource portfolios. These other costs would not be useful in differentiating the portfolios under consideration in the IRP.

PVRR is calculated by taking the sum of all relevant costs, expressed as revenue requirements, in each year of the planning period and discounting those costs back to the present. The discount rate is the Company's weighted average cost of capital ("WACC"). Capital costs for new resources are levelized over the useful life of the resource for the calculation of annual revenue requirements. This levelization ensures that the costs and benefits of each resource are aligned in time so as not to bias the capacity expansion model against resources with operating lives that extend beyond the end of the planning horizon. Capital cost levelization is a function of the capacity expansion model, which solves for the least cost resource mix, in PVRR terms, that meets customer needs and other requirements.

Bill Impacts

Projected IRP customer bill impacts, expressed as the compound annual growth rate in the average monthly bill of a typical residential customer using 1,000 kWh of electricity per month, are a useful complement to the total cost in PVRR terms. The IRP bill impact projections provide information on expected cost to customers at specific snapshots in time, allowing the Company to balance total costs and near-term impacts. Similar to PVRR, the IRP bill impact calculation excludes costs not germane to resource planning, costs that are unavoidable, and certain costs that are the same across resource portfolios. In contrast to the PVRR calculation, capital costs for new resources are included using a depreciating rate base methodology rather than being levelized over the life of the asset. IRP bill impacts to not reflect the depreciation of existing assets, schedules for which are determined in rate making and are not necessarily directly linked to actual retirement dates for physical assets.

The bill impacts use the Duke Energy Indiana's WACC, the 2024 Duke Energy Indiana Rate Case Cost of Service ("COS"), and the 2024 Duke Energy Indiana Rate Case residential bill as the basis for the calculation. In addition, revenue requirements are adjusted to reflect only the retail impacts. All bill impacts for the 2024 IRP are calculated as incremental changes from a 2025 starting point. Because the bill impact metric is an estimate of percentage change over time, it is sensitive to conditions in the year used as a starting point. For instance, if fuel prices happen to be particularly high in the base year, then percent change over time may look relatively low, all else being equal. As with PVRR, IRP bill impact calculations are useful for portfolio comparison only and cannot be used to estimate actual customer bills at any point in the future.

Present Value of Revenue Requirements Results

Table C-79 below shows the annual revenue requirements for each of the generation strategies in the Reference Scenario. These annual revenue requirements are used to calculate PVRR. The table also provides levelized revenue requirements over the planning period in terms of $/MWh for each generation strategy in the Reference Scenario, calculated using a discount rate of 7.28%.

Table C-79: Annual and Levelized Revenue Requirements for Generation Strategies in Reference Scenario (Annual in Nominal $MM, Levelized in $/MWh)

Year	Convert/ Co-fire	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier (Stakeholder)	Annual Energy (GWh)
Levelized Rev. Req. ($/MWh)	**$62.52**	**$58.90**	**$60.43**	**$60.68**	**$61.28**	**$60.72**	N/A
2025	$1,511	$1,516	$1,515	$1,508	$1,507	$1,501	33.09
2026	$1,801	$1,807	$1,806	$1,747	$1,745	$1,736	33.50
2027	$1,934	$1,870	$1,878	$1,909	$1,926	$1,877	34.45
2028	$1,785	$1,747	$1,751	$1,739	$1,746	$1,840	34.92
2029	$2,176	$1,999	$2,178	$1,744	$1,725	$2,095	34.81
2030	$2,074	$1,839	$1,794	$2,052	$2,185	$2,087	35.21
2031	$2,160	$1,528	$1,797	$1,641	$1,812	$1,773	35.54
2032	$2,334	$2,186	$2,222	$2,380	$2,410	$2,225	35.90
2033	$2,400	$2,236	$2,361	$2,397	$2,391	$2,372	36.19
2034	$2,330	$2,267	$2,345	$2,429	$2,402	$2,324	36.52
2035	$2,402	$2,311	$2,362	$2,464	$2,425	$2,355	36.88
2036	$2,456	$2,361	$2,406	$2,510	$2,475	$2,403	37.29
2037	$2,528	$2,436	$2,490	$2,591	$2,551	$2,484	37.60
2038	$2,683	$2,530	$2,649	$2,680	$2,632	$2,639	37.98
2039	$2,699	$2,575	$2,632	$2,646	$2,706	$2,615	38.36
2040	$2,801	$2,664	$2,719	$2,767	$2,824	$2,729	38.80
2041	$2,941	$2,808	$2,865	$2,912	$2,968	$2,877	39.04
2042	$3,036	$2,896	$2,956	$3,005	$3,053	$2,972	39.36
2043	$3,171	$3,083	$3,091	$3,142	$3,192	$3,104	39.72
2044	$3,416	$3,242	$3,208	$3,252	$3,308	$3,215	40.16

Figure C-20 below shows total cost in PVRR terms over the 20-year planning period for the three scenario portfolios that the Company developed for each of the six generation strategies (one portfolio for each generation strategy in each worldview).

Figure C-20: PVRR Through 2044 for Generation Strategies in Worldviews

Figure C-21 below shows the PVRR through 2044 for the Blend 2 Strategy Variations. “Blend 2 No 111” refers to the Blend 2 portfolio for the Reference Scenario (the Preferred Portfolio) operating in a future without the EPA CAA Section 111 Rule. This is a separate variation from the “No 111” case.

Figure C-21: PVRR Through 2044 for Blend 2 Strategy Variations

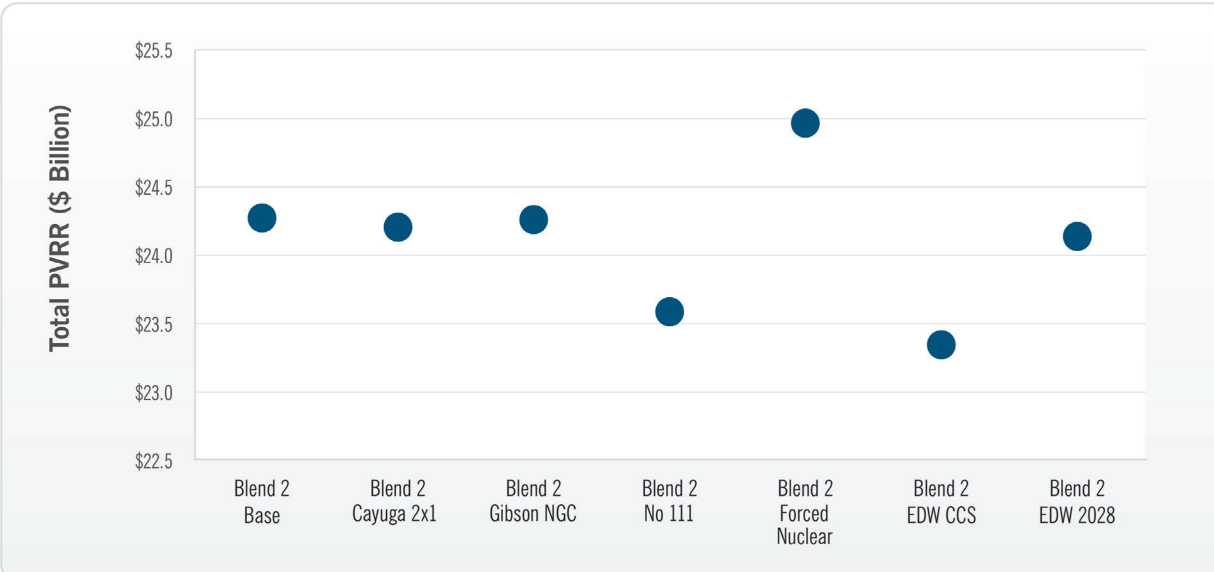


Figure C-22 below shows the PVRR through 2044 for the High Load and Low Load sensitivity analysis cases, as well as the base case PVRR for each generation strategy in the Reference Scenario.

Figure C-22: PVRR Through 2044 for High and Low Load Sensitivities

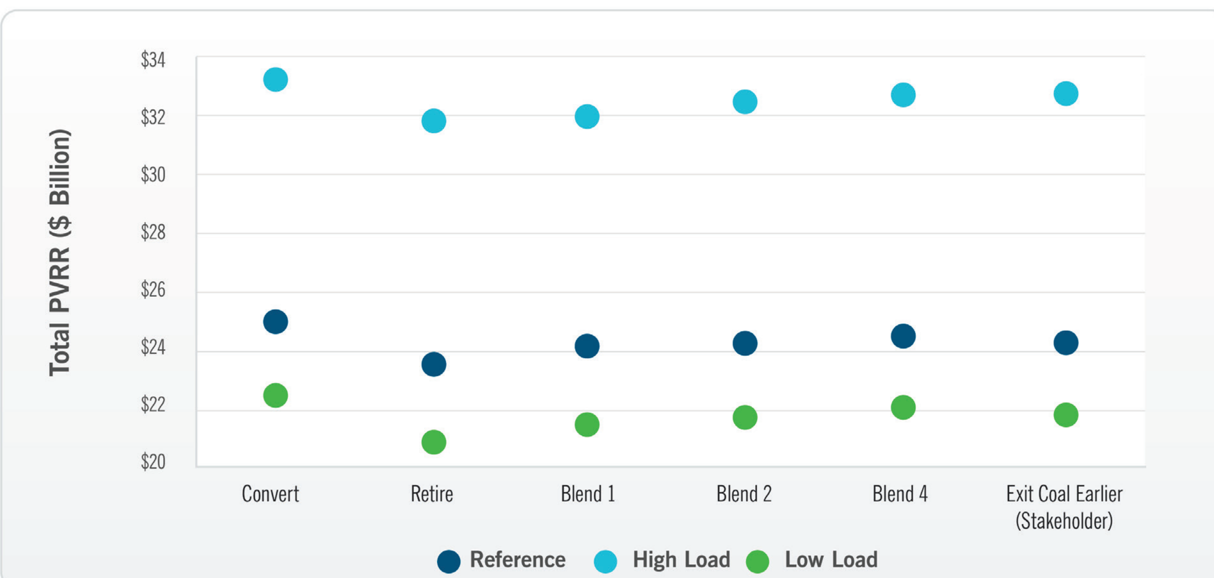


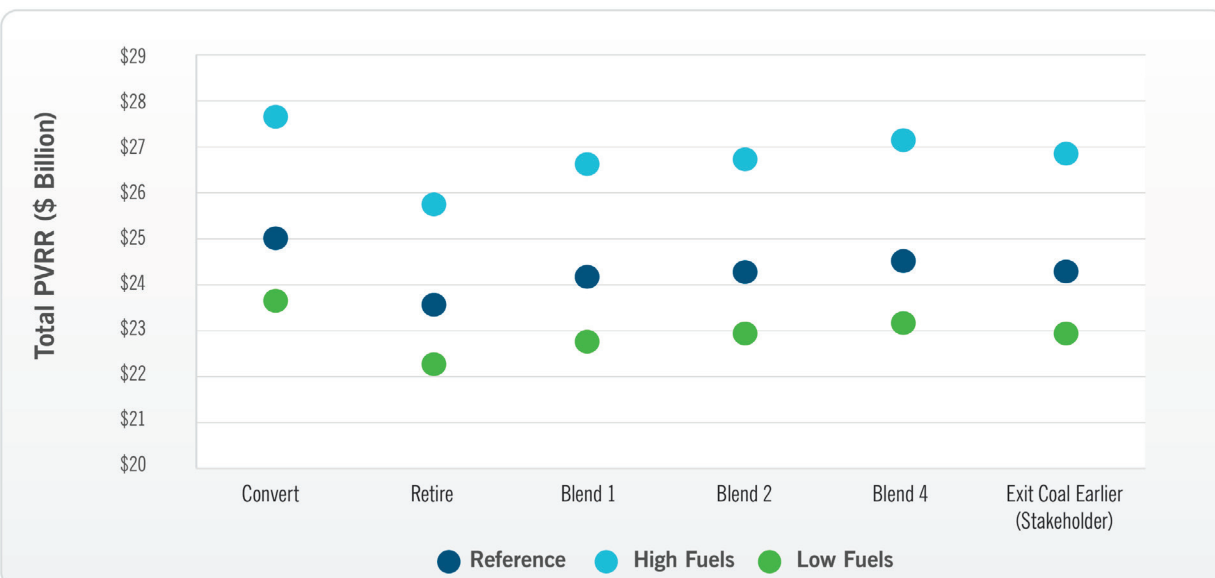
Figure C-23 below shows the PVRR through 2044 for the High CC and CT Cost sensitivity analysis cases, as well as for the base case PVRRs for the generation strategies in the Reference Scenario.

PVRR changes are greater for portfolios that include larger amounts of new CC capacity. PVRRs are very similar across portfolios in the High CC and CT Cost cases.

Figure C-23: PVRR Through 2044 for High CC and CT Cost Sensitivity

Figure C-24 below shows the PVRR through 2044 for the High and Low Fuel Price sensitivity analysis cases, as well as the base case PVRRs for the generation strategies in the Reference Scenario. Note that there is little change to relative PVRR across portfolios in the sensitivity analysis cases.

Figure C-24: PVRR through 2044 for High and Low Fuel Price Sensitivities



Net Market Purchases

The Company's economic participation in the MISO energy market provides cost savings for customers. However, market exposure also carries cost risk to the extent that projected portfolio costs are contingent upon the accuracy of forecasted MISO energy prices. For this reason, the Company conducts rigorous risk analysis around MISO energy market exposure, and net economic energy purchases (purchases net of sales) are a key output of the production cost model.

Figure C-25 below shows the annual net market purchases for each generation strategy in the Reference Scenario. Purchases are highest in the mid-2030s, and portfolios that rely more on relatively inefficient aging steam units for capacity are more exposed to MISO prices for energy.

Figure C-25: Annual Net Market Purchases for Generation Strategies in Reference Scenario

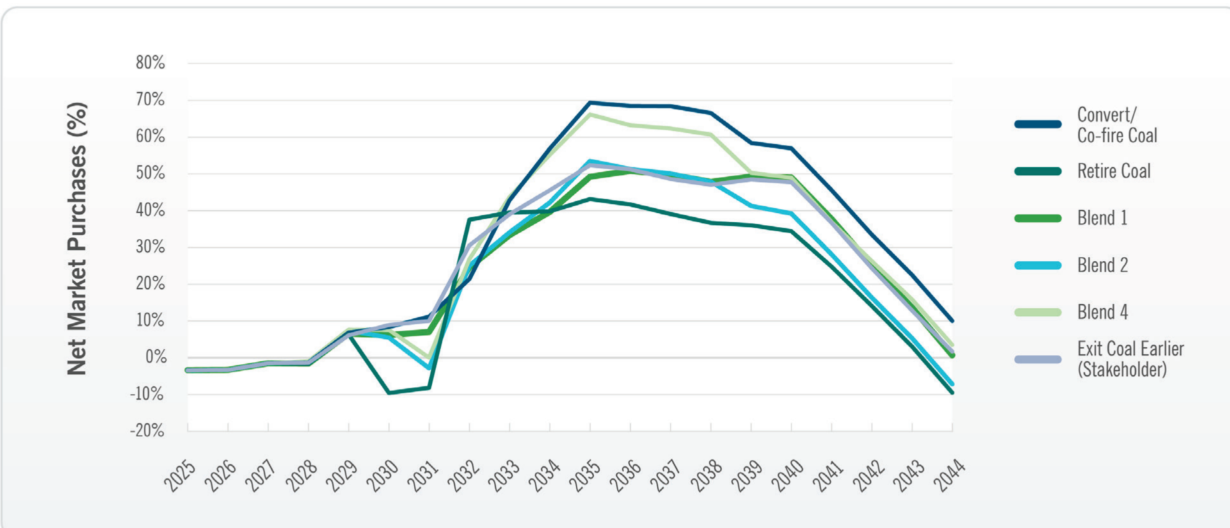


Figure C-26 below shows annual net market purchases for the generation strategies in the Aggressive Worldview. A CO_2 tax is imposed in this scenario starting in 2030. Market exposure is highest in the early 2030s for all generation strategies and declines over time as new resources are brought online.

Figure C-26: Annual Net Market Purchases for Generation Strategies in Aggressive Worldview

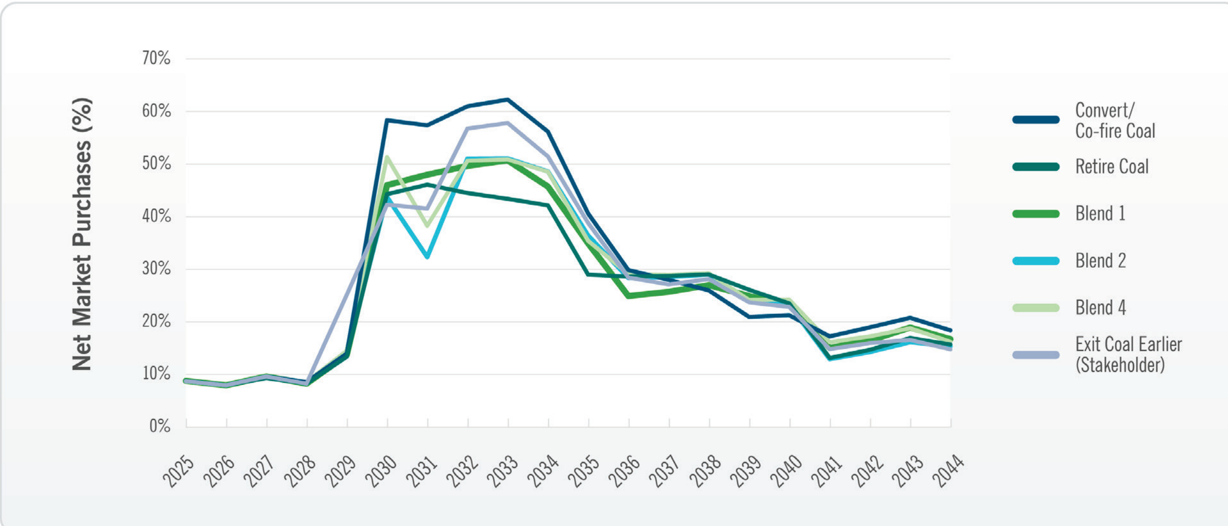
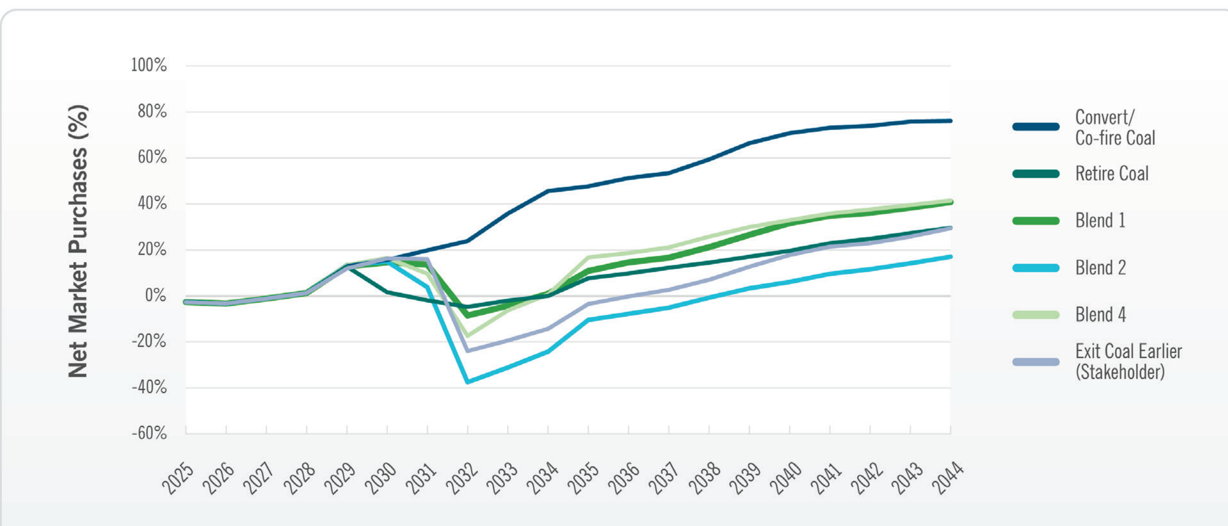


Figure C-27 below shows annual net market purchases for the generation strategies in the Minimum Worldview. The EPA CAA Section 111 Rule is rolled back in this scenario, eliminating the capacity factor constraint on new CCs. The Convert/Co-fire Coal Strategy, which does not include any new advanced class CC units, carries significantly more exposure to the MISO energy market than the other strategies in this potential future.

Figure C-27: Annual Net Market Purchases for Generation Strategies in Minimum Worldview



Non-CO_2 Emissions

The Company uses CO_2 emissions as the representative indicator of environmental sustainability for the 2024 IRP scorecard because CO_2 emissions are highly correlated with other indicators of sustainability. This section provides information on the other types of emissions simulated in 2024 IRP analysis. These include NO_X, SO_2, mercury (Hg), and particulate matter ("PM"). Tables C-80 through C-83 below provide projections for these other emissions for each generation strategy in the Reference Scenario. All emissions apart from PM are direct outputs of the EnCompass production cost model. PM is estimated based on the current average for existing coal units.

Table C-80: Annual NOx Emissions for Generation Strategies in Reference (000 Short Tons)

Year	Convert/ Co-fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier
2025	14.8	14.8	14.8	14.8	14.8	14.8
2026	15.2	15.2	15.2	15.2	15.2	15.2
2027	15.2	15.2	15.2	15.2	15.2	15.2
2028	15.7	15.7	15.7	15.7	15.7	15.7
2029	14.4	14.4	14.4	14.4	14.4	14.5
2030	12.1	12.8	12.4	8.2	7.9	9.8
2031	12.1	12.8	12.6	6.8	6.3	9.6
2032	10.9	0.6	6.2	3.4	5.2	6.2
2033	7.3	0.5	4.6	2.5	3.0	4.5
2034	4.0	0.5	3.0	1.6	1.5	3.0
2035	2.3	0.3	1.6	0.6	0.5	1.5
2036	2.1	0.3	1.6	0.7	0.7	1.4
2037	1.8	0.3	1.4	0.5	0.4	1.3
2038	1.8	0.3	1.3	0.4	0.3	1.2
2039	0.9	0.3	1.1	0.3	0.1	1.1
2040	0.7	0.3	0.9	0.2	0.1	0.8
2041	0.5	0.3	0.6	0.2	0.1	0.6
2042	0.4	0.3	0.7	0.2	0.1	0.6
2043	0.5	0.3	0.9	0.2	0.1	0.8
2044	0.5	0.3	0.7	0.2	0.1	0.2

Table C-81: Annual SO_2 Emissions for Generation Strategies in Reference (000 Short Tons)

Year	Convert/ Co-fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier
2025	15.7	15.7	15.7	15.7	15.7	15.7
2026	16.0	16.0	16.0	16.0	16.0	16.0
2027	16.0	16.0	16.0	16.0	16.0	16.0
2028	16.2	16.2	16.2	16.2	16.2	16.2
2029	14.0	14.0	14.0	14.0	14.0	11.9
2030	1.3	11.9	9.5	7.4	1.8	4.0
2031	1.9	11.8	9.4	7.3	1.9	3.9
2032	1.8	0.0	0.0	1.8	1.8	0.0
2033	1.3	0.0	0.0	1.3	1.3	0.0
2034	0.7	0.0	0.0	0.8	0.7	0.0
2035	0.2	0.0	0.0	0.2	0.2	0.0
2036	0.3	0.0	0.0	0.3	0.3	0.0
2037	0.1	0.0	0.0	0.1	0.1	0.0
2038	0.1	0.0	0.0	0.1	0.1	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0
2041	0.0	0.0	0.0	0.0	0.0	0.0
2042	0.0	0.0	0.0	0.0	0.0	0.0
2043	0.0	0.0	0.0	0.0	0.0	0.0
2044	0.0	0.0	0.0	0.0	0.0	0.0

Table C-82: Annual Hg Emissions for Generation Strategies in Reference (Short Tons)

Year	Convert/ Co-fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier
2025	0.048	0.048	0.048	0.048	0.048	0.048
2026	0.049	0.049	0.049	0.049	0.049	0.049
2027	0.050	0.050	0.050	0.050	0.050	0.050
2028	0.050	0.050	0.050	0.050	0.050	0.050
2029	0.044	0.044	0.044	0.044	0.044	0.030

2030	0.005	0.043	0.029	0.022	0.009	0.015
2031	0.007	0.043	0.029	0.021	0.007	0.015
2032	0.007	0.000	0.000	0.007	0.007	0.000
2033	0.005	0.000	0.000	0.005	0.005	0.000
2034	0.003	0.000	0.000	0.003	0.003	0.000
2035	0.001	0.000	0.000	0.001	0.001	0.000
2036	0.001	0.000	0.000	0.001	0.001	0.000
2037	0.001	0.000	0.000	0.001	0.001	0.000
2038	0.000	0.000	0.000	0.000	0.000	0.000
2039	0.000	0.000	0.000	0.000	0.000	0.000
2040	0.000	0.000	0.000	0.000	0.000	0.000
2041	0.000	0.000	0.000	0.000	0.000	0.000
2042	0.000	0.000	0.000	0.000	0.000	0.000
2043	0.000	0.000	0.000	0.000	0.000	0.000
2044	0.000	0.000	0.000	0.000	0.000	0.000

Table C-83: Annual PM Emissions for Generation Strategies in Reference Case (Pounds)

Year	Convert/ Co-fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier
2025	729	729	729	729	729	729
2026	740	740	740	740	740	740
2027	746	746	746	746	746	746
2028	748	748	748	748	748	748
2029	663	663	663	664	664	453
2030	384	651	437	454	439	228
2031	363	645	434	385	362	223
2032	307	0	0	171	306	0
2033	166	0	0	126	171	0
2034	69	0	0	72	75	0
2035	20	0	0	21	25	0
2036	39	0	0	26	37	0
2037	20	0	0	13	20	0
2038	11	0	0	11	11	0

2039	2	0	0	0	2	0
2040	0	0	0	0	0	0
2041	0	0	0	0	0	0
2042	0	0	0	0	0	0
2043	1	0	0	0	1	0
2044	0	0	0	0	0	0

Water Consumption & Discharge

Several resource types use water for cooling and other purposes. Table C-84 below provides the projected water consumption and discharge volumes for the Preferred Portfolio by year over the 20-year planning period. Projected water usage declines dramatically when the Cayuga coal units, which employ a once-through cooling system, are retired.

Water withdrawal refers to the total amount of water taken from a source, such as a river, lake, or aquifer, for use in the thermal electric generating process, primarily for cooling purposes. Water consumption is the portion of this withdrawn water that is not returned to the original source, typically lost through evaporation, incorporation into products, or other processes. Water discharge, on the other hand, is the water that is returned to the source after it has been used in the generating process.

Table C-84: Annual Water Consumption and Discharge for Existing Thermal Units and Potential New Units for Blend 2 in Reference Case (Million Gallons)

Year	Existing Units		New Units	
	Consumption	Discharge	Consumption	Discharge
2025	20,897	323,130	–	–
2026	21,381	338,484	–	–
2027	21,411	338,331	–	–
2028	20,897	338,490	–	–
2029	19,811	338,376	–	–
2030	12,324	90,968	986	278
2031	10,663	3,120	1,964	554
2032	7,166	3,140	1,949	550
2033	6,332	2,933	1,941	548
2034	5,364	2,680	1,922	542
2035	4,416	2,475	1,932	545
2036	4,142	2,220	1,928	544

2037	4,227	2,263	1,922	542
2038	4,175	2,198	1,930	545
2039	3,915	1,825	1,916	541
2040	3,846	1,525	1,915	540
2041	3,802	1,331	1,911	539
2042	3,810	1,364	1,885	532
2043	3,727	1,000	1,920	542
2044	3,800	1,320	1,916	541

Stochastic Operational Simulations

In this IRP, the Company has leveraged two additional models, SERVM and PowerSIMM, to further explore the operational characteristics of the generation profiles produced in the EnCompass model. Both of these power system models are considered “stochastic” due to their ability to simulate multiple, path-dependent scenarios of power system dispatch. Stochastic modeling can reveal uncertainties and risks that single scenario, deterministic models may not show.

The Company used SERVM to explore islanded portfolio dispatch to identify future periods of heighted operational risk arising from uncertainties in load and generator performance. This “Enhanced Reliability Evaluation” measures the potential reliance of the Duke Energy Indiana system on the broader MISO market to maintain reliability.

The Company used PowerSIMM to provide a more granular look at market exposure as it relates to the various portfolios developed using EnCompass. Market exposure represents a risk to the consumer, both in terms of power price sensitivity (how much the portfolio relies on purchase power purely for economic reasons) and fuel price sensitivity (how much the portfolio relies on gas and coal markets to justify the dispatch economics of generating assets). Market exposure to power prices risks upside shocks to the consumer, while market exposure to fuel prices risks generating asset underperformance in years with low market power pricing relative to the assumed baseline.

Each model relies on somewhat different simulation strategies, and they are used in this IRP to address different aspects of future operational uncertainty. SERVM uses a fast dispatch algorithm that allows the model to explore the thousands of simulations (11,000 in this application) necessary to capture “tail risks” which drive reliability events. PowerSIMM generates more detailed market pricing information; fewer simulations (301 in this application) are necessary to capture operational and economic characteristics than are needed for reliability analysis. As will be discussed in more detail, for consistency in stochastic modeling results, the SERVM and PowerSIMM analyses share inputs where possible, including the historical weather years, load simulations, and renewable output simulations.

Enhanced Reliability Evaluation: SERVM

In this IRP, the Company added an additional modeling step to compare and assess portfolios on their contributions to future reliability. The broader context of and reasons for this “Enhanced Reliability Evaluation” approach are discussed in more detail in Appendix E (Reliability & Resource Adequacy), but at a high level this new modeling step is intended to capture the degree to which a changing resource mix aligns to meeting customer load. This is done by modeling the Duke Energy Indiana system using the SERVM model to simulate the dispatch of the generation strategies in the Reference Scenario through 11,000 simulations for the 2028 and 2035 study years. Astrapé Consulting develops and licenses the SERVM model and also developed and configured many of the base inputs (such as hourly load simulations) for the Company’s modeling representation of the Duke Energy Indiana and MISO systems.

Historical Weather Years

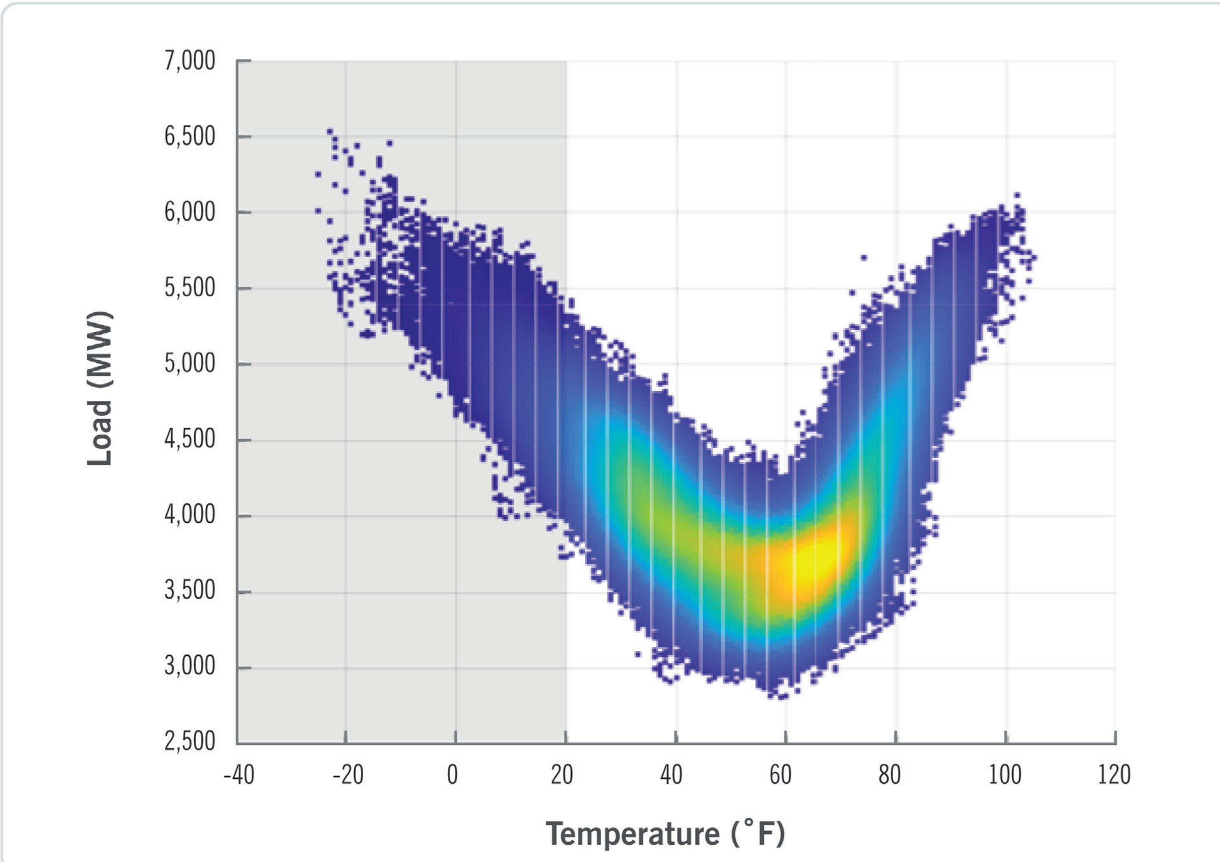
The stochastic analyses in this IRP use 44 years of historical weather – spanning the period from 1980 to 2023 – to help capture the real-world variability in weather that can drive correlations between temperatures and loads, as well as the weather-dependent output of wind and solar. Using actual historical weather inputs captures the historical distribution of weather conditions which, in conjunction with generator outages, lead to periods of potential risk in the power system. This length of history balances the benefits of a larger sample size to characterizing risk and the potential decreasing quality and relevance of historical data farther back in time.

Load Simulation

The SERVM model relies on hourly load simulations aligned to the historical temperatures of the 44 weather years used in the analysis. Astrapé Consulting uses a combination of neural network and linear regression models to project future hourly loads based on the Company’s historical load history. To maintain consistency with the broader IRP, these hourly modeled loads are scaled to ensure that the median simulation in SERVM matches the 50/50 peak load and 50/50 annual energy of the load forecast used in the EnCompass model.

Figure C-28 below shows the result of these load simulations for the 2035 study year, illustrating the resulting general relationship between the historical weather year temperatures and the modeled Duke Energy Indiana customer load. The color of the data points indicates the frequency with which a given temperature and load level is expected to occur, with warmer colors indicating a higher frequency. The shaded dark area encompassing temperatures of 20 degrees F and below captures the hours used in the estimation of 95th percentile cold weather performance.

Figure C-28: Load Simulations Used in the Stochastic Models



Weather-Dependent Renewables Profiles

The enhanced reliability evaluation uses renewable generation profiles with hourly generator output aligned to actual weather history in the 44 weather years use in the SERVM analysis. The wind profiles are based on hourly wind speeds from the European Center for Medium-range Weather Forecasting's Reanalysis v5 ("ERA5") historical meteorological data product.[5] The solar output profiles are based on historical irradiance data from the National Renewable Energy Laboratory's National Solar Radiation Database ("NSRDB").[6] As NSRDB's data history only begins in 1998, similar day-matching is used to create hourly profiles for the prior weather years in the analysis.

SERVM Outage Modeling

The SERVM model has multiple avenues for simulating the loss of generator capabilities, including both full unit outages and partial derates, which are a key driver in potential power system risks. To

[5] European Centre for Medium-Range Weather Forecast, ECMWF Reanalysis v5 (ERA5), available at https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5.

[6] National Renewable Energy Laboratory, National Solar Radiation Database, available at https://nsrdb.nrel.gov/.

model thermal units (such as CTs, coal, and CCs) in SERVM, the model uses historical actual outage histories to generate simulations of both planned and unplanned (i.e., forced) outages and derates. For planned outages and derates, such as recurring annual maintenance activities, SERVM optimizes the placement and timing these events to align with the lowest net-load periods of the year in the simulation. For forced outages, SERVM draws from a unit's historical realized time-to-failure ("TTF", i.e., the amount of unit runtime between forced outages) and time-to-repair ("TTR", i.e., the duration for which the unit is offline). To help align the realized availabilities in the SERVM simulations to the assumptions used in the IRP's EnCompass modeling, the Company uses SERVM's built-in capability to scale the TTF and TTR values to produce the intended level of Equivalent Forced Outage Rate for a unit.

Because generator forced outages and derates occur with an element of randomness, the SERVM studies are run with 50 iterations of forced outage simulations to ensure the statistical stability of any resulting portfolio performance metrics.

SERVM Economic Load Forecast Error Uncertainty

In addition to the core power system operational uncertainties, long-term growth in customer demand may also be higher or lower than forecast. To include this element of risk in the Enhanced Reliability Evaluation, the Company directly utilizes MISO's assumptions about potential long-term economic load forecast uncertainty to capture the impact from different scenarios of long-term demand growth. As of MISO's 2024/2025 LOLE probabilistic study[7] these assumptions are seen in Table C-85 below:

Table C-85: Economic Load Forecast Error Assumptions

Economic Load Forecast Error					
Forecast Error Level	-2.0%	-1.0%	0.0%	1.0%	2.0%
Probability	4.8%	24.1%	42.1%	24.1%	4.8%

Enhanced Reliability Evaluation Results

The SERVM model produces hourly system dispatch and – if Duke Energy Indiana resources are not sufficient in a given hour – the amount of load potentially unserved. In the context of the Company's integration into the MISO market, the common reliability modeling metrics of Expected Unserved Energy ("EUE") and Loss-of-Load-Expectation ("LOLE") are indicative of the *magnitude* and *frequency* (in days per year) of the extent to which customer load could be reliant on the diversity benefits of the market.

Table C-86 below shows the average annual results for each of the generation strategies in the Reference Scenario in the 2028 and 2035 study years. To explore the change in portfolio performance

[7] MISO Inc., Loss of Load Expectation Study Report for Planning Year 2024/2025, April 2024, available at https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf.

between the two years, 2035 results for both LOLE and EUE are also presented as a ratio to 2028. Note that values in the "2035 (relative)" columns are relative to the average of all generation strategies in 2028, with a baseline average LOLE of 49.5 days of market reliance/year and an average EUE % of 0.5% of load reliant on the market/year.

Table C-86: Enhanced Reliability Evaluation Summary Results

	LOLE (average days with market reliance per year)			EUE % (average % of market reliant load per year)		
Generation Strategy	**2028**	**2035**	**2035 (relative)**	**2028**	**2035**	**2035 (relative)**
Convert/Co-Fire	47.5	108.5	2.2	0.5%	1.7%	3.4
Retire	53.4	93.5	1.9	0.5%	0.8%	1.6
Blend 1	48.8	48.4	1.0	0.5%	0.5%	0.9
Blend 2	47.5	60.1	1.2	0.5%	0.6%	1.1
Blend 4	49.1	110.4	2.2	0.5%	1.4%	2.8
Exit Coal Earlier	50.7	129.4	2.6	0.5%	1.5%	2.9

Stochastic Production Cost Model: PowerSIMM

The PowerSIMM production cost model, produced by Ascend Analytics, is designed for high granularity simulation of an electric power system. Similar to the detailed EnCompass production cost model, PowerSIMM uses a specified set of resources established in the capacity expansion model to perform a detailed hourly forecast of generation by resource. PowerSIMM, however, analyzes the portfolios in hundreds of stochastic simulations of weather, load, solar, wind, forced outages, fuel and power prices to produce ranges of potential outcomes The mean of each variable simulated matches the reference case worldview as follows:

- Load – Mean of annual energy matches base load forecast.
- Fuel prices – Mean monthly gas and coal prices match the base gas and coal price forecasts. Fuel prices vary by day by iteration based on forward volatility curves for each commodity.
- Power prices – Mean monthly forward prices match the power price forecast from the Reference Scenario. Power prices vary by hour by iteration based on forward volatility curves.

In this IRP, the Company analyzed the six generation strategies in the Reference Scenario for years 2028, 2035, 2040, and 2044. To analyze each generation strategy, the unit characteristics of all resources selected by EnCompass' capacity expansion model were modeled within PowerSIMM. Utilizing the load, outage, fuel, and power price simulations, the model optimally generated hourly generation forecasts by resource. This stochastic analysis produced a range of outcomes for each generation strategy for key output variables such as net market purchases, CO_2 emissions and operating costs.

Weather & Load Simulation

The stochastic analysis constructs its weather simulation by replicating 43 historical weather years (1980 to 2022) seven times to construct 301 simulations, referred to as *iterations*. A date mapping between historical time periods and simulated dates and iterations is maintained and applied to historical predicted load and renewable generation to maintain a tight temporal correlation between weather, load, solar and wind generation. Table C-87 below shows a small subset of this date mapping.

Table C-87: Sample Mapping Between Historical Weather Years and Stochastic Simulation Periods

Simulation Iteration	Simulation Date Range	Historical Date Range
1	2024-2045	1980-2001
2	2024-2045	1981-2002
3	2024-2045	1982-2003
…	…	…
22	2024-2045	2001-2022
23	2024-2044	2002-2022
23	2045	1980
24	2024-2043	2003-2022
24	2044-2045	1980-1981
…	…	…
300	2024-2025	2021-2022
300	2026-2045	1980-1999
301	2024	2022
301	2025-2045	1980-2000

There are two load inputs in the stochastic model. The first represents MISO system load net of renewables. This input is developed by Astrapé Consulting in the SERVM model for the MISO Futures 2A planning scenario. It is used in PowerSIMM to drive the hourly power price simulation described below. The second load represents Duke Energy Indiana load. This input is also developed by Astrapé for SERVM for the Reference Scenario. The same date mapping referenced above is also applied to the predicted load histories to construct the simulated hourly load for the stochastic analysis.

Solar & Wind Simulation

The conventional solar and wind simulations used in PowerSIMM were taken from SERVM using the same weather mapping used for the weather and load simulation. This was done to maintain the correlation between weather, load and renewables as well as ensure agreement between the two models.

Profiles for solar paired with storage were calculated using an optimization process that maximizes the economic value of the batteries in energy shifting and capturing otherwise clipped energy. This process uses all the hourly simulated power prices from PowerSIMM and the DC solar profiles from SERVM to calculate optimal charge and discharge decisions for each iteration to produce hourly 8760 profiles for net generation from the site.

Market Price Simulation

PowerSIMM jointly simulates monthly commodity forward prices using a correlated vector auto-regressive process with mean reversion. The commodities include gas, power, coal and oil. The monthly average values are then scaled to match the reference forward curves used in the EnCompass model to maintain parity between the models. The forward volatilities used in simulation are market option implied volatilities which are extended to the year 2044 using a year-over-year exponential decay calculated from the last two years of observed market data. PJM West Hub is used as a market proxy for power volatilities. The correlation in the model between the commodity contracts are derived using long-term historical co-movements between the different commodity forward curves. The correlations for certain commodity pairs (like power & gas or on-peak and off-peak prices) may be increased to reduce the likelihood of large deviations from historical ranges for market implied heat rates or positive on-peak to off-peak power price ratios. Figures C-29 through C-31 below depict the simulated percentiles of gas and power prices from the monthly forward price simulation. The light blue bands represent the 25th to 75th percentile or the middle 50% of simulations while the light green shaded bands indicate the 10th-90th percentiles. The ratio of power prices to gas prices is termed *implied market heat rate* and is shown below in Figure C-31. This chart is overlaid with the historical range of market heat rates. It is evident that beyond 2033, the implied heat rate is projected to be lower than 90% of historical market heat rates observed in the last five years. This has significant implications for the profitability of the Duke Energy Indiana generation fleet. Low implied market heat rates indicate that market prices are lower than the generating cost of gas units resulting in higher proportions of market purchases as illustrated in Figures C-29 through C-31 below. This is observed in both the EnCompass and PowerSIMM net market purchase projections for 2035 and 2040.

Figure C-29: Simulated Natural Gas Price Statistics (Henry Hub)

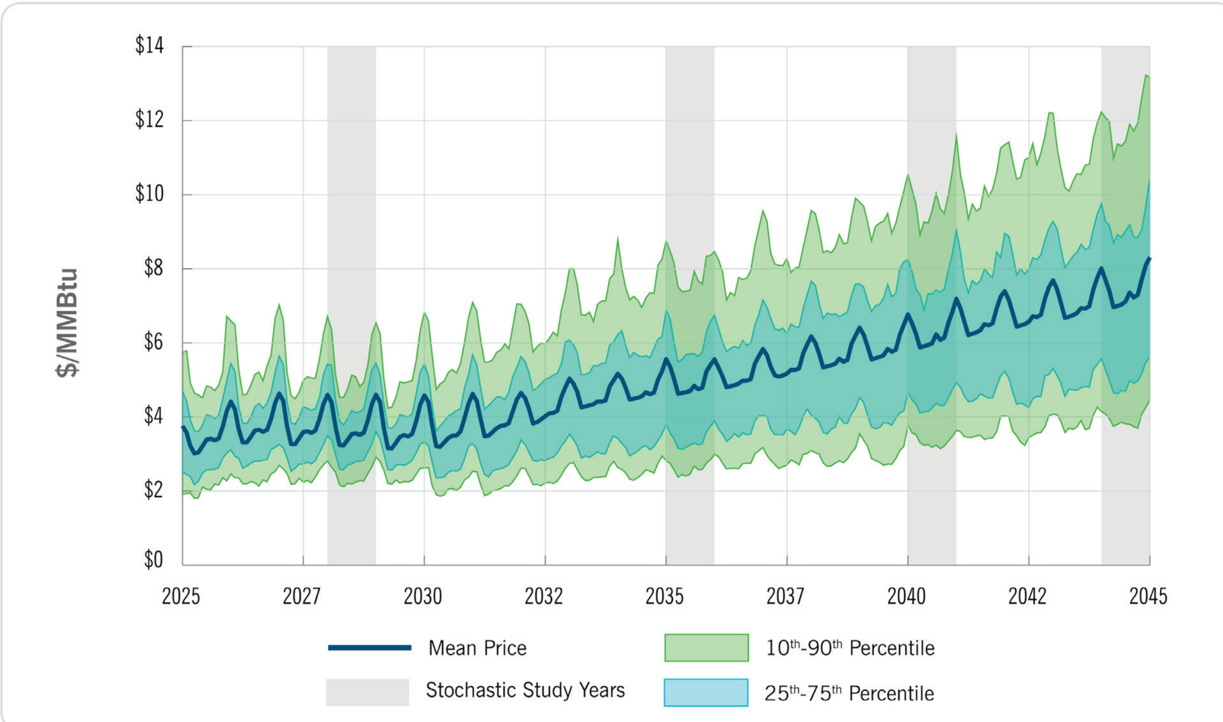


Figure C-30: Simulated Power Price Statistics (MISO-IN/KY)

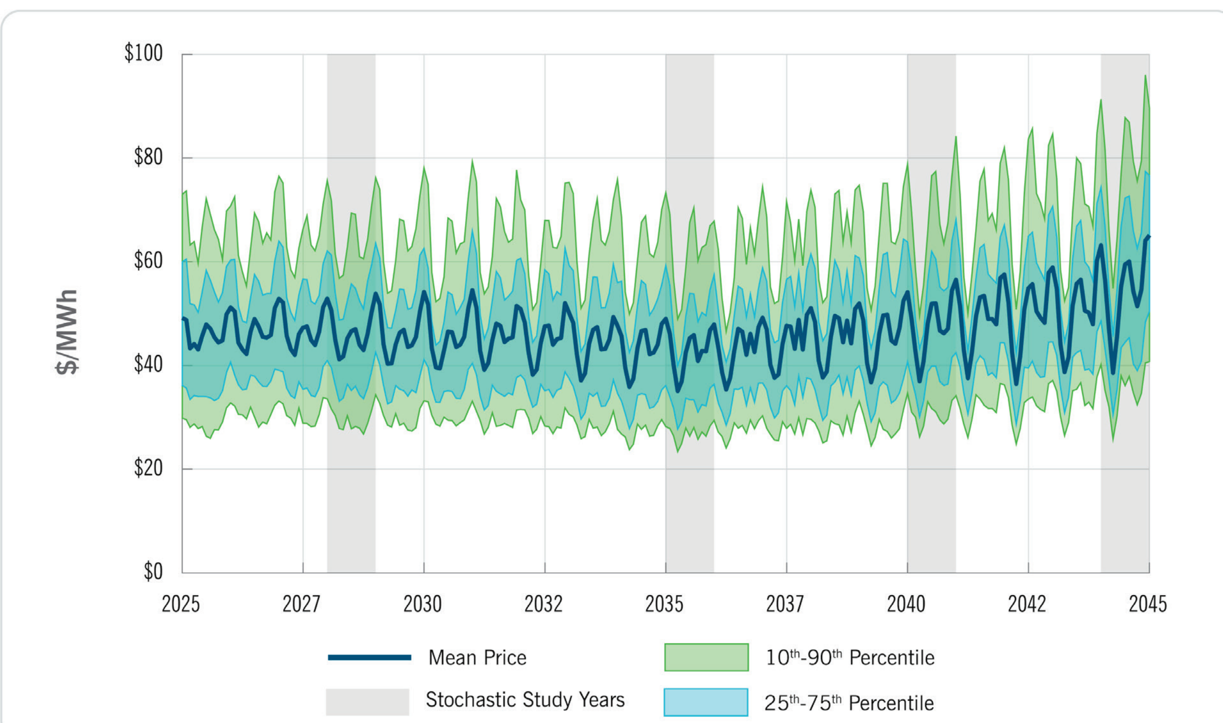
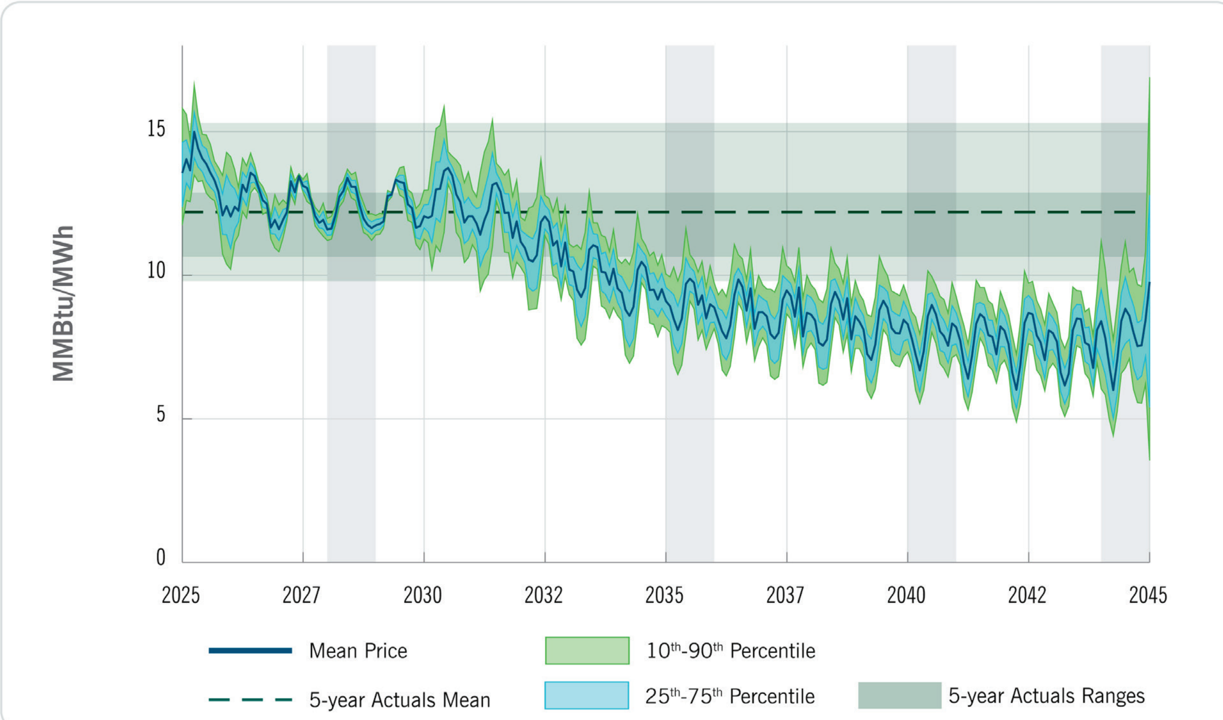


Figure C-31: Simulated Ranges of Implied Market Heat Rates (Ratio of Power Prices to Natural Gas Prices)



PowerSIMM performs a spot price simulation for gas (daily) and power (hourly) to introduce intra-month volatility and intraday power price shapes. These are time series models that incorporate temperature and MISO net load as independent predictors. The parameters of these models are fit to historical daily/hourly prices.

Transportation costs for gas units were modeled as multiplicative and additive factors as appropriate to calculate all-in prices for each unit for every simulation iteration and simulation date.

Forced Outage Simulation

PowerSIMM's forced outage simulation module was used to generated forced outage simulations for all thermal and battery units. The outage durations in this model follow a generalized Pareto distribution with parameters fit to historical outages by asset class. The forced outage model ensures that the average equivalent forced outage rate ("EFOR") demand performance matches the expected EFOR for each unit.

Economic Dispatch & EPA CAA Section 11 Rule Post-Processing

PowerSIMM performs an economic dispatch of all units in a portfolio to the simulated hourly price. Batteries perform optimal energy shifting to maximize revenue. Renewable assets are modeled as must-take and not dispatched by price. Hydro and EE were not simulated in PowerSIMM but were instead taken as constant generation profiles from EnCompass. This was done to maintain parity between the models and due to insufficiency in model fidelity to adequately simulate the stochastic dynamics of these asset classes.

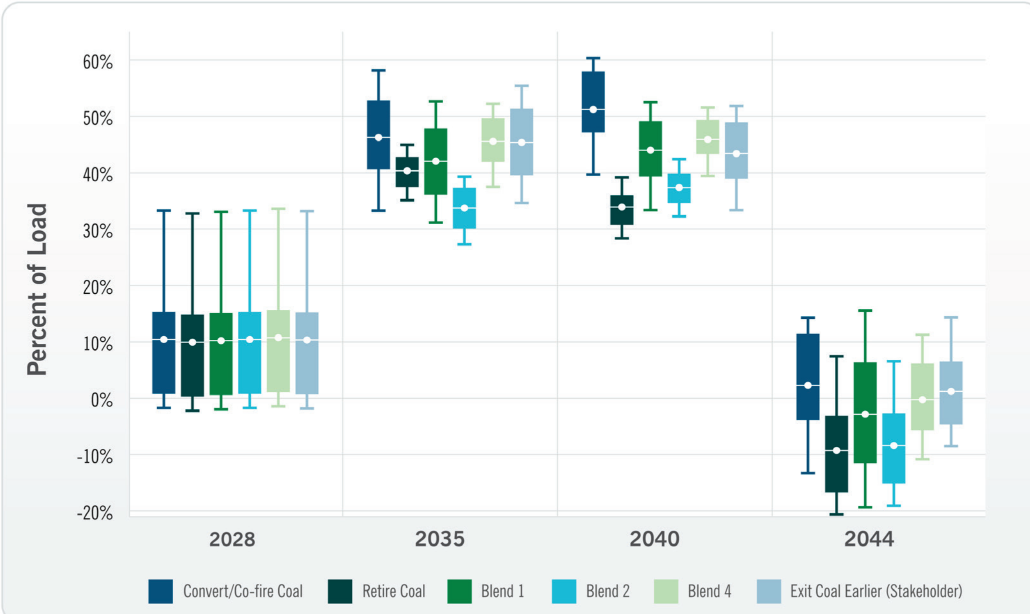
EPA CAA Section 111 Rule limits on new combined cycle and combustion turbines were enforced by performing a post processing on hourly outputs from PowerSIMM. For every study year and for every simulation iteration, if a unit was exceeding its capacity factor limit, the unit was turned off in the hours in the year identified to be the least profitable to run the unit. This process was continued until the capacity factor of the unit was reduced below the annual limit. This ensured that the limited hours of generation available to the unit were the most profitable for customers.

Stochastic Portfolio Comparisons

Figures C-32, C-33 and C-34 below show the ranges of possible values for economic net purchases, operating costs and CO_2 emissions, respectively, from the stochastic analysis of the six portfolios in the Reference Scenario for the four chosen study years. In these charts, the white central markers represent the mean or average of all 301 iterations. The central boxes span the 25th to 75th percentile or the middle 50% of iterations. The whiskers represent the 10th and 90th percentile, roughly 80% of all outcomes.

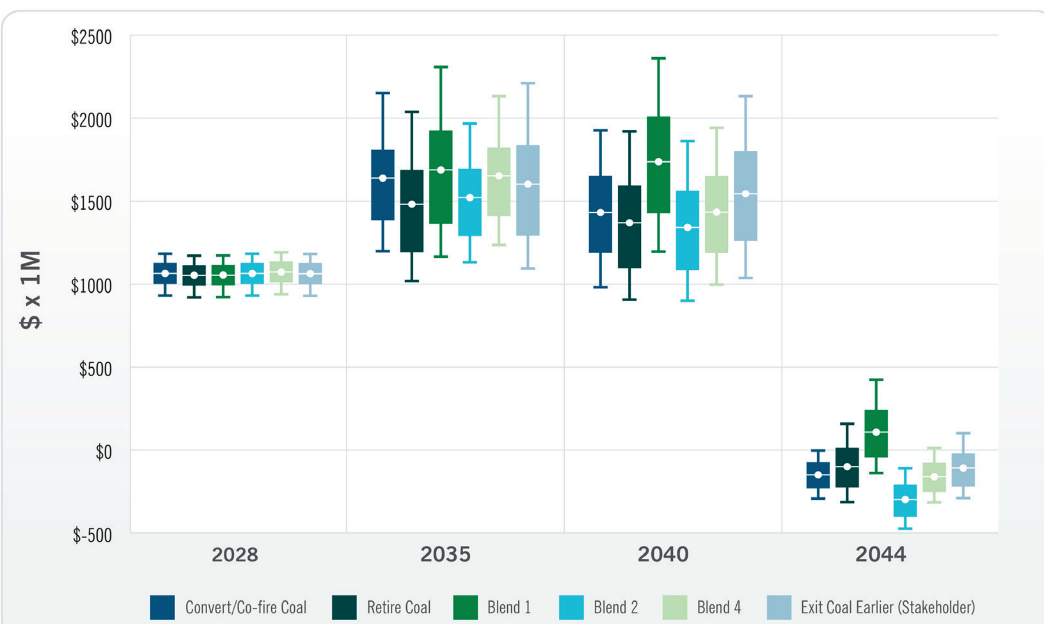
As expected, the downward trending implied market heat rates shown in Figure C-31 above are a principal cause of the increasing net market purchases from year 2028 to 2040 because the thermal fleet is economically dispatched based on market favorability. The significantly lower net market purchases in 2044 are due to higher capacities of renewables which (since they are non-dispatchable) sell a significant portion of their energy to the market, offsetting and even exceeding annual purchases.

Figure C-32: Stochastic Ranges for Annual Market Net Purchases as a Percent of Annual Load in Reference Scenario Under Standard Economic Dispatch



Operating costs in Figure C-33 below represent the sum of the stochastic cost to serve load and the deterministic fixed costs and ITC/PTC from EnCompass for each portfolio/study year. The costs are in nominal dollars and exclude any capital costs that would be incurred for each portfolio.

Figure C-33: Stochastic Ranges for Annual Operating Costs in Reference Scenario Under Standard Economic Dispatch



CO_2 emissions in Figure C-34 below include both CO_2 generated from Duke Energy Indiana generating assets as well as from market net purchases.

Figure C-34: Stochastic Ranges for Annual CO_2 Emissions in Reference Scenario Under Standard Economic Dispatch

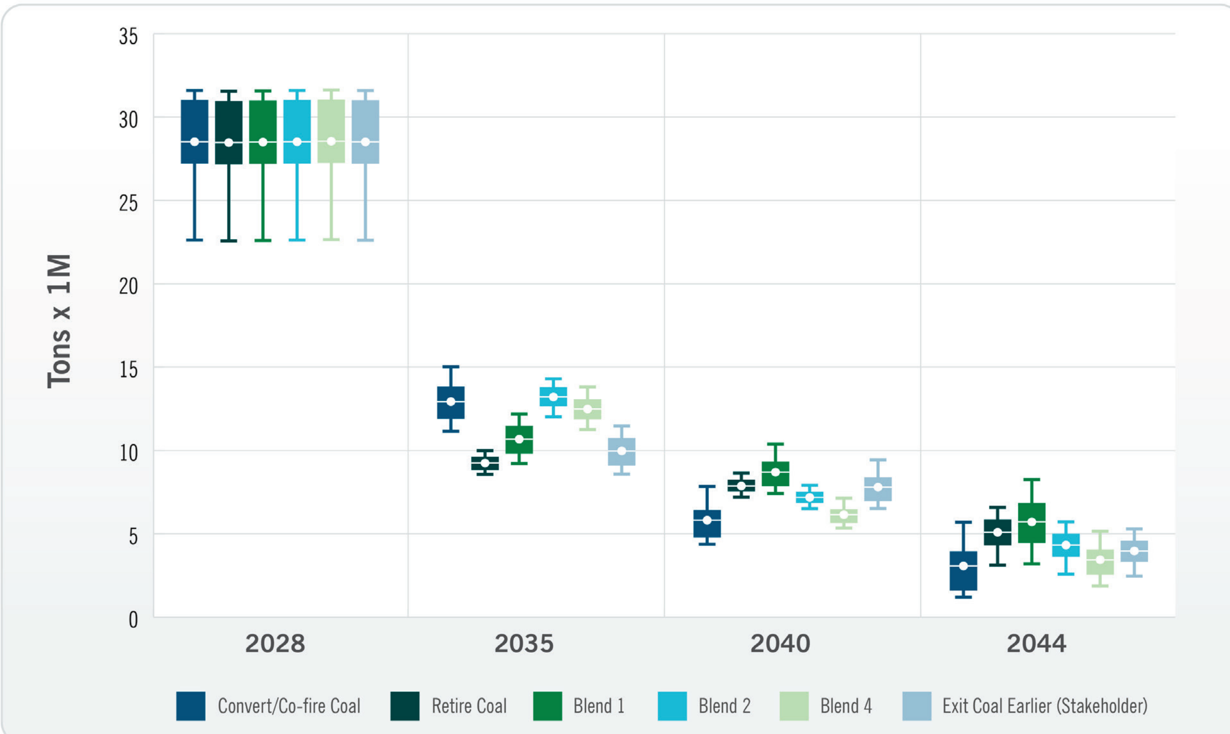
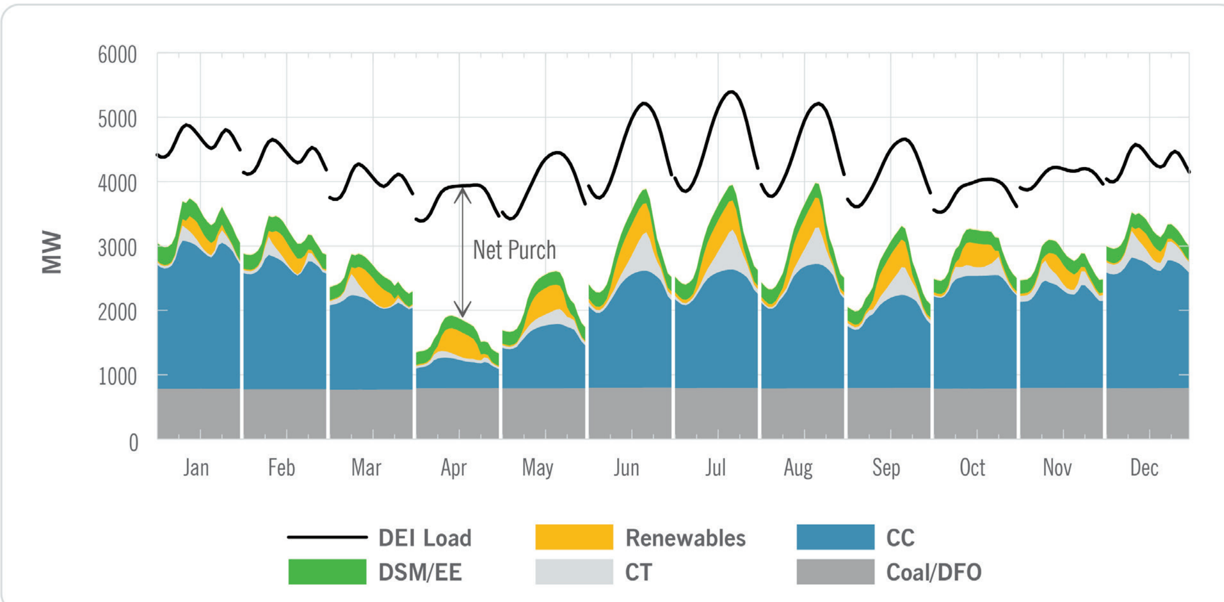


Figure C-35 below provides further insight into the seasonal behavior of the Blend 2 portfolio for study year 2035 for the average of all iterations. The average hourly generation profile for each month is shown with the generation stack color coded by asset class. The average hourly load profile by month is overlaid as a solid line. The gap between total generation and load represents average net market purchases. These market purchases reflect an opportunistic participation in the market to reduce cost to serve load by purchasing energy at a lower cost than the cost to run the fleet at higher capacity factors. It does not represent a reliance on the market for energy, as evidenced in the following discussion on maximum generation dispatch.

Figure C-35: Month-by-Hour Generation Profile for Blend 2 in 2035 Under Economic Dispatch



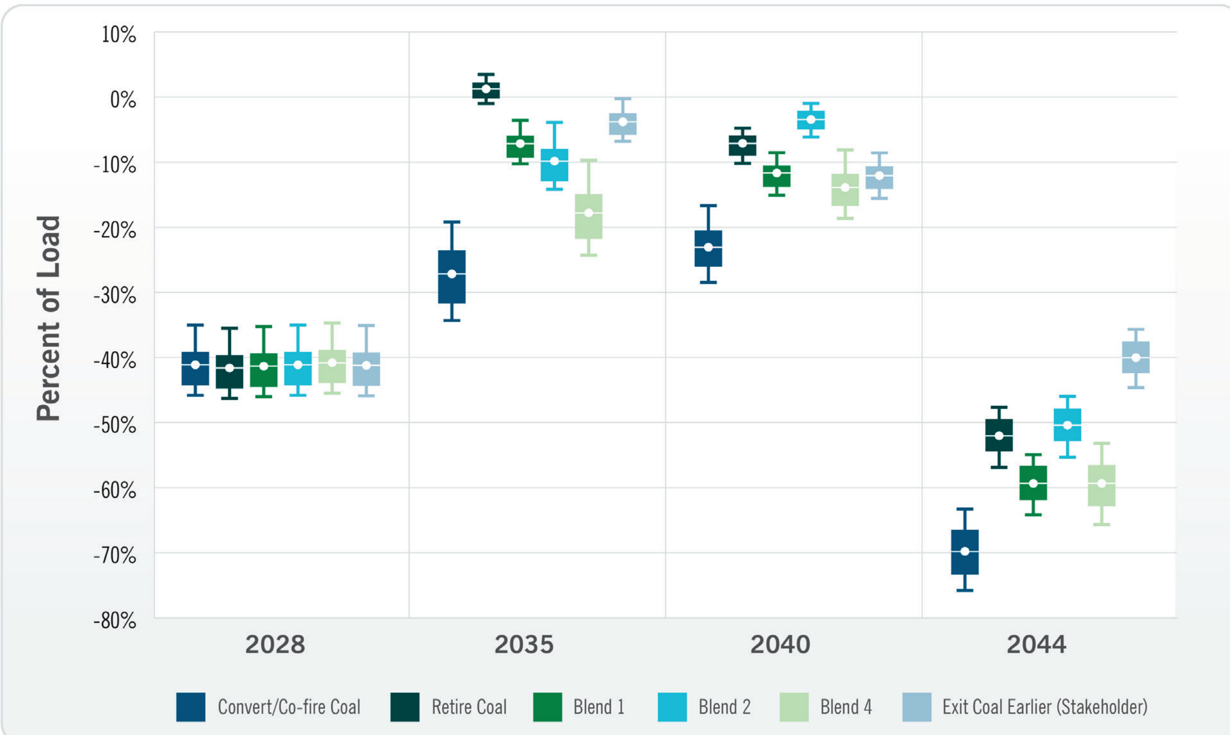
Maximum Generation Dispatch

Maximum generation dispatch refers to a theoretical mode of operation where dispatchable units are run at their maximum available capacity (subject to outages and EPA CAA Section 111 Rule restrictions). The goal of this analysis is to assess the energy sufficiency of a portfolio on an average basis independent of market prices. This analysis can be useful in understanding the lower bounds of market reliance of different portfolios.

To calculate the maximum generation dispatch metrics, the economic generation for each thermal unit is replaced by its generation capacity for each hour, for each simulation iteration. Renewable units are not adjusted. Thermal units are still subject to outages as well as the processing for EPA restrictions. To minimize excessive generation in certain seasons, the EPA CAA Section 111 Rule processing was modified to distribute the limited energy of new combined cycles by seasonal load rather than power prices. The fuel consumption and operating cost metrics are then recalculated using the updated generation numbers and aggregated to calculate portfolio-level metrics.

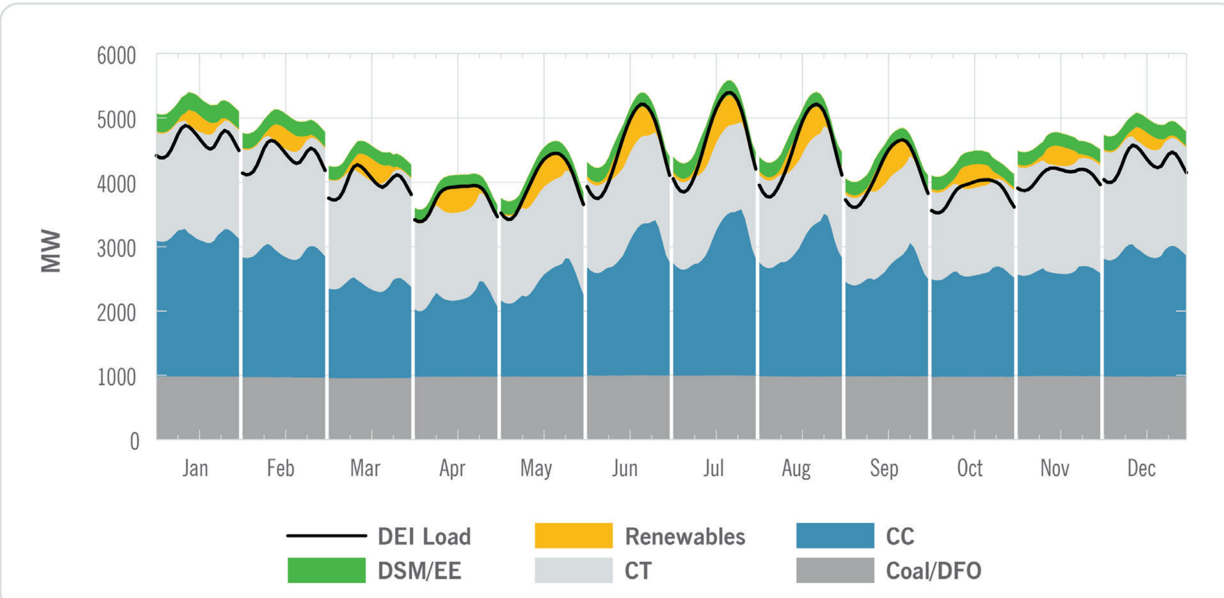
Figure C-36 below shows annual net market purchases for the six portfolios in four study years for the Reference Scenario under maximum generation dispatch. All portfolios in all years, except for the Retire portfolio in 2035, are net sellers of energy on an annual basis as indicated by negative values in the Y-axis.

Figure C-36: Stochastic Ranges for Annual Market Net Purchases as a Percent of Annual Load in Reference Scenario Under Maximum Generation Dispatch



The seasonal behavior of the Blend 2 portfolio for study year 2035 for the average of all iterations under maximum generation dispatch is shown in Figure C-37 below. In this mode of operations, all hours in all months, on average, demonstrate sufficient energy to meet load obligations. This exercise serves to illustrate how portfolios with high market purchases in certain economic conditions can still contain sufficient resources to meet energy needs without undue reliance on the market.

Figure C-37: Month-by-Hour Generation Profile for Blend 2 in 2035 Under Maximum Generation Dispatch



Scorecard Metrics

Duke Energy Indiana developed and used a set of stakeholder-informed scorecard metrics to evaluate candidate portfolios and guide the selection of the Preferred Portfolio. These were informed by the Five Pillars while also considering risk and uncertainty. A detailed description and the purpose of each metric is covered in Chapter 2. Tables C-88 through C-94 below provide the method for calculating each metric with reference to the necessary outputs from the EnCompass model.

Table C-88: Environmental Sustainability Metrics

Metric	Description	Calculation
CO_2 Emissions Reduction	Percent CO_2 emissions reduction at specified years (2035, 2044) relative to Planning Year 1 (2025), including estimated CO_2 emissions associated with market purchases	Projected CO_2 emissions in the specified year (2035, 2044) divided by CO_2 emissions in the baseline year (2025), minus 1. Result multiplied by negative one to show % reduction as a positive number.

Cumulative CO_2 Reduction	Cumulative volume of CO_2 reduction over the planning period, reflected as million tons reduced through 2044 relative to Planning Year 1 (2025) including estimated CO_2 emissions associated with market purchases	Sum of the annual differences from the 2025 baseline over the 20-year study period.
CO_2 Intensity of Duke Energy Indiana Portfolio	CO_2 emissions from Duke Energy Indiana portfolio resources (owned and PPA) per megawatt-hour of energy generated by those resources	CO_2 emissions from Duke Energy Indiana resources divided by energy generated by Duke Energy Indiana resources (i.e., excluding market purchases).

Table C-89: Affordability Metrics

Metric	Description	Calculation
Present Value of Revenue Requirements	Total forecasted revenue requirement associated with resource plan investments over the planning period, discounted to present	Includes all annual costs for operating the system along with the economic carrying charge ("ECC") for all new resources. Annual values are discounted back to the beginning of 2025 using the Company's WACC.
Customer Bill Impact	Average annual rate impact to customers over 5-year and 10-year time periods expressed as projected compound annual growth rate ("CAGR") in customer bill of typical residential household using 1,000 kWh/month associated with resource plan investments, inclusive of existing unit on-going costs	CAGR uses depreciating rate base methodology instead of Economic Carrying Charge used by EnCompass. The bill impact calculation builds revenue requirements for each portfolio utilizing capital, O&M and IRA benefits from each plan. Bill impacts consist of the development of return and depreciation of each type of asset through the study period. The bill impacts use Company-specific WACC, 2024 Rate Case COS, and 2024 Rate Case residential bill as the basis of the calculation. In addition, revenue requirements are adjusted to reflect only the retail impacts. All bill impacts are calculated as incremental changes from 2025.

Table C-90: Reliability Metrics

Metric	Description	Calculation
Fast Start Capability	Fast start capable resource capacity MW as a percent of peak load in 2035. Fast start capable resources include CTs and battery.	Sum of installed capacity (MW) of resources that are fast start capable divided by the peak load (MW) in 2035.
Spinning Reserve Capability	Spinning reserve capable resource capacity MW as a percent of peak load in 2035. Spinning reserve capable resources include steam, CC, CT, CHP, and hydro.	Sum of installed capacity (MW) of resources that are capable of providing spinning reserves divided by the peak load (MW) in 2035.

Table C-91: Resiliency Metrics

Metric	Description	Calculation
Resource Diversity	An empirically-derived diversity baseline of the system's capacity resources by technology type, as measured by the Herfindahl-Hirschman Index ("HHI") – the sum of squares of technology share in the portfolio on a firm capacity basis in 2035	Each resource on the system is placed in one of the following categories: Battery Storage, Coal, CC, CT, DR, EE, Hydroelectric, IGCC, Internal Combustion, Solar, Wind, CHP, Nuclear. Divide firm capacity (MW) of each resource category in peak month of 2035 (June) by the total system firm capacity in peak month of 2035 (June), resulting in a percentage share for each portfolio resource type. Multiply each value by 100 and square. Sum the squares to give HHI value shown on scorecard.
Performance in 95th Percentile Extreme Weather Event	Stochastically simulated EUE as percent of load during coldest weather (95^{th} percentile or colder) observed in Indiana over the past 44 years with market purchases turned off	Sum of EUE divided by the sum of customer load during hours with temperatures of 20 degrees or less. EUE is simulated in SERVM.

Table C-92: Risk & Uncertainty Metrics – Cost Risk

Metric	Description	Calculation
Cost Variability Across Scenarios	The minimum and maximum PVRRs of the portfolio across the scenarios evaluated	Difference between the PVRR in the Aggressive Worldview (consistently the most costly) and the Minimum Worldview (consistently the least costly) for each generation strategy.
IRA Exposure	Portion of cumulative MW additions assumed to receive IRA credits relative to total resource additions through 2030 and 2035	Sum of cumulative installed MW added that are eligible for IRA tax credits divided by the total cumulative installed MW added by both 1/1/2030 and 1/1/2035.

Table C-93: Risk & Uncertainty Metrics – Market Exposure

Metric	Description	Calculation
Fuel Market Exposure	Energy generated by resources with exposure to coal and gas market prices as percent of total fleet generation, averaged annually over the planning period	Divide total annual coal and gas generation (GWh) by total annual net energy generation (GWh) for each year of the study period. Average all annual values over study period to get a single value (%) for fuel market exposure of the portfolio.
Maximum Energy Market Exposure	Absolute value of maximum single year annual energy purchases net of sales as percent of load	Divide annual total net purchases (annual purchases minus annual sales) by the total annual energy requirement for each year of the planning period. The maximum single-year value (%) is shown on the scorecard (2035 for most strategies, 2036 for Blend 1).

Table C-94: Risk & Uncertainty Metrics – Execution Risk

Metric	Description	Calculation
Cumulative Resource Additions in (1) MW and (2) as % of Current System	Cumulative MW additions of all capacity resource technology types, including DSM, through 2030 and 2035, expressed in MW and as percent of total MW capacity serving customers today	Sum of installed capacity additions (MW) of all resource types by 1/1/2030 and 1/1/2035 to provide cumulative resources additions in MW terms. Divide sum by total installed system capacity (MW) as of 1/1/2025 to provide as a percentage of total system capacity.

Preferred Portfolio

Guided by the scorecard presented in Chapter 4, the Company identified the Blend 2 portfolio developed for the Reference Scenario as the Preferred Portfolio for the 2024 IRP. Support for this decision can be found in Chapter 5. Additional details on the Blend 2 portfolio are supplied in this section, including summer and winter Load, Capacity and Reserve tables. Note that these tables show summer and winter firm capacity, reserve margin targets, and actual projected reserves in MW terms. Similar detailed tables found earlier in this Appendix display installed capacity.

Load, Capacity, & Reserves Tables for the Preferred Portfolio

Tables C-95 and C-96 below provide the projected load, firm capacity by resource type, and capacity reserves for the Preferred Portfolio. Coal capacity for 2030 reflects a 51.6% derate to Cayuga Unit 2 in all seasons. Transmission network upgrades required to increase generating capacity at the site, accommodating the additional MW provided by the new CC units, are expected to be completed by 2031. Capacity amounts are presented on a beginning-of-year basis in these tables, and in all figures and tables in the IRP.

Table C-95: Summer Peak Load, Firm Capacity, and Reserves for Preferred Portfolio (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Load - Summer	5,972	5,893	5,917	5,924	5,934	5,945	5,956	5,969	5,989	6,010	6,034	6,059	6,087	6,118	6,150	6,191	6,247	6,302	6,370	6,433
EE	37	56	79	95	117	140	161	185	205	222	231	240	254	263	267	244	248	252	252	250
DR	558	563	569	549	553	554	558	561	564	567	570	573	576	580	583	586	589	592	596	599
IVVC	43	45	48	46	47	47	47	47	47	47	47	47	48	48	49	50	50	50	51	51
Coal	3,391	3,391	3,391	3,202	3,202	1,079	886	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired Coal/Gas	-	-	-	-	-	929	929	929	929	929	929	929	929	929	-	-	-	-	-	-
CC	264	264	264	245	245	1,316	1,940	3,201	3,201	3,201	2,956	2,956	2,956	2,956	2,956	2,956	2,956	2,956	2,956	2,956
CT	1,364	1,366	1,368	1,315	1,314	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312
Internal Combustion	9	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
CHP	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Hydroelectric	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Solar PV	11	10	54	141	141	194	181	151	122	92	63	32	20	18	55	58	100	144	169	180

Wind	10	10	10	-	-	-	-	-	-	-	-	34	68	99	131	152	172	184	202	200
Battery	12	12	12	343	343	390	390	390	390	390	390	390	390	390	907	931	931	931	931	931
Capacity Purchase	613	435	725	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Firm Summer Capacity	6,377	6,226	6,594	6,009	6,035	6,036	6,479	6,850	6,845	6,835	6,573	6,588	6,628	6,670	6,335	6,362	6,432	6,496	6,542	6,553
Reserve Margin - Summer	6.8%	5.6%	11.4%	1.4%	1.7%	1.5%	8.8%	14.8%	14.3%	13.7%	8.9%	8.7%	8.9%	9.0%	3.0%	2.8%	3.0%	3.1%	2.7%	1.9%
Required Reserve Margin - Summer	5.6%	5.6%	5.6%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%

Table C-96: Winter Peak Load, Firm Capacity, and Reserves for Preferred Portfolio (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Peak Load - Winter	5,563	5,503	5,550	5,583	5,612	5,650	5,696	5,749	5,807	5,869	5,937	6,008	6,078	6,150	6,221	6,292	6,344	6,401	6,462	6,530
EE	28	42	63	71	92	118	137	158	178	198	208	217	224	230	235	236	238	243	241	237
DR	506	567	567	457	458	457	459	463	466	469	472	475	478	481	484	488	491	494	497	500
IVVC	48	50	53	45	46	46	46	46	46	46	46	47	47	48	49	49	50	50	50	51
Coal	3,332	3,332	3,332	2,763	2,763	922	753	-	-	-	-	-	-	-	-	-	-	-	-	-
Co-fired coal/gas	-	-	-	-	-	794	794	794	794	794	794	794	794	794	-	-	-	-	-	-
CC	251	251	251	204	204	1,170	1,702	2,766	2,766	2,766	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562
CT	1,554	1,558	1,561	1,410	1,408	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406	1,406
Internal Combustion	8	8	8	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
CHP	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Hydro	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Solar PV	6	5	30	8	8	11	10	9	9	8	7	6	6	7	22	26	55	86	127	176
Wind	10	10	10	-	-	-	-	-	-	-	-	57	114	170	227	280	334	386	439	489

Battery	12	12	12	332	332	378	378	378	378	378	378	378	378	378	878	901	901	901	901	901
Capacity Purchase	740	848	713	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Firm Winter Capacity	6,531	6,718	6,635	5,334	5,355	5,347	5,731	6,065	6,087	6,109	5,917	5,985	6,053	6,120	5,906	5,991	6,080	6,171	6,268	6,365
Reserve Margin - Winter	17.4%	22.1%	19.6%	-4.5%	-4.6%	-5.4%	0.6%	5.5%	4.8%	4.1%	-0.3%	-0.4%	-0.4%	-0.5%	-5.1%	-4.8%	-4.2%	-3.6%	-3.0%	-2.5%
Required Reserve Margin - Winter	16.8%	16.8%	16.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%	-5.8%

Confidential Technical Attachments

In addition to the data provided throughout the technical appendices of the 2024 IRP, the Company has submitted with this IRP additional confidential technical attachments to the Indiana Utility Regulatory Commission including EnCompass input and output files, load forecast files, and other information as required by the Indiana Administrative Code.

Appendix D: Load Forecast

Highlights

- This Appendix presents forecasts for the number of retail customers, system energy, and demand at time of peak for the Duke Energy Indiana service territory over the 2025-2044 study period.
- Load forecasting provides the foundation for resource planning and includes the study of alternative load forecast scenarios that were used to evaluate resource portfolios and risk in the 2024 Duke Energy Indiana Integrated Resource Plan.
- Major factors that affect the long-term outlook include economic growth in the service territory, market and policy driven efficiency and electrification trends, economic development successes that alter the landscape of the service area economy, and the surge in electric vehicle demand which impacts system hourly peak and monthly energy generation.
- Changes to the load factor and load duration curves are driven by the expansion in industrial electric consumption over the forecast horizon and electric vehicles penetrating the transportation market.

The 2024 Duke Energy Indiana (or the "Company") Integrated Resource Plan ("IRP") load forecasts provide projections of the energy and peak demand needs for customers in the Duke Energy Indiana service area. Only by recognizing the size of the need for energy, including the dynamics that will shape that evolving need during the years to come, can a prudent plan to meet those needs be developed.

The energy forecast projects the electric load required to serve Duke Energy Indiana retail customer classes. As a product, it is more than a number – it represents a series of descriptions, offered monthly, hourly or at time of peak, about how demand for energy will evolve under different possible futures. Duke Energy Indiana uses econometric analysis, described in more detail below, to prepare models that estimate how historically measured changes in sales can be attributed to variation in a series of predictive variables, measuring economic and weather conditions. Future projections of those predictive variables can then be used to calculate a series of future outlooks for sales measures, as well as demand for energy at time of peak. It is most helpful to consider groups of customers that respond to similar economic dynamics. The multivariable deterministic modeling approach that is used to forecast load provides many explicit levers for evaluating future market and policy environments over the forecast horizon.

Overview of Load Forecasting

Duke Energy Indiana develops the energy load forecast in four steps: (1) a service area economic forecast is obtained; (2) an energy forecast is prepared by estimating statistical models based on these economic conditions and market driven energy efficiency analysis; (3) ex post modifications that account for the growth in electric vehicles ("EVs"), behind-the-meter ("BTM") solar, economic development, and wholesale contracts are considered; and (4) using the energy forecast, summer and winter peak demand forecasts are developed. The result allows analysis of the impact of varying inputs on sales, including substitution of different economic and weather conditions and energy efficiency and electrification trends.

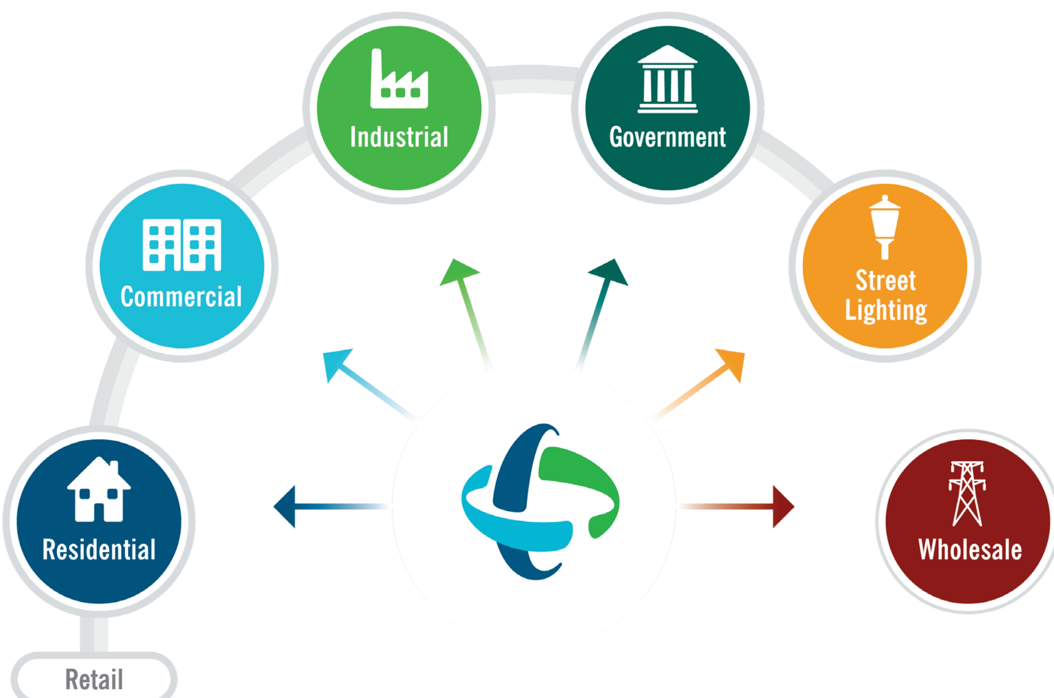
Energy projections are developed with econometric models using key economic factors such as income, electricity prices, inflation, industrial production indices, commercial employment, weather, appliance efficiency trends, BTM solar trends, and EV trends. Population and household data is also used in the residential customer model.

The economic projections used in the Resource Plan forecast are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the Indiana service area. Moody's forecasts consist of economic and demographic projections, which are used in the energy and demand models. The Moody's forecast is derived from a fully integrated regional model of counties, metro areas, states, U.S., and international economies. The model addresses population, household, demographic cohorts, commercial employment, and production output by industry, inflation, government policies, technology trends, labor saving productivity enhancements, labor force, unemployment, interest rates, and investment activity. The databases span over 50 years of history and the forecast spans through 2050. The models and forecast performance are rigorously tested and a forecast update and writeup are produced each month. Moody's provides an unbiased forecast used by industries and government entities worldwide.

Customer Classes

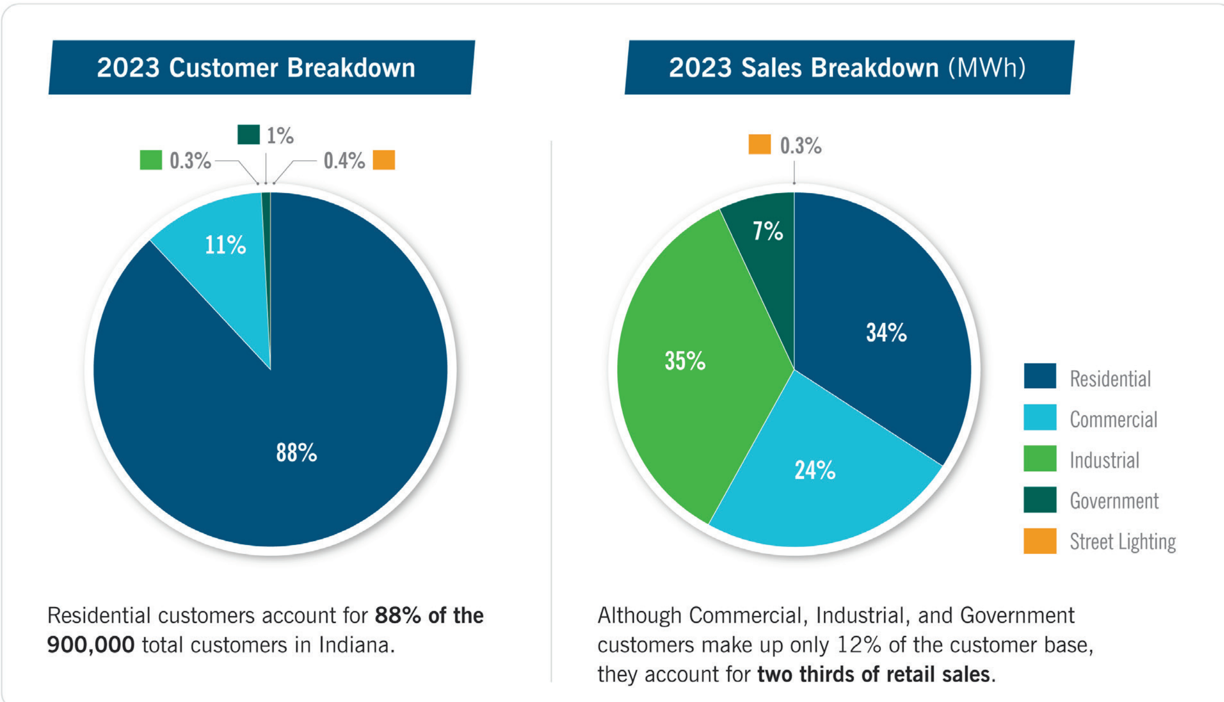
This edition of the load forecast includes the years 2025-2044 and represents the needs of Duke Energy Indiana's customers. The Company's customers are segmented into classes to account for the unique energy needs and usage patterns of different customer types. As outlined in Figure D-1 below, the load forecast consists of three major retail classes (Residential, Commercial, and Industrial), two minor classes (Government and Street Lighting), and Wholesale.

Figure D-1: Customer Classes



The market forces that impact the Duke Energy Indiana service area load growth are significantly affected by customer mix. While residential customers accounted for 88% of the total customers in 2023, they accounted for approximately 34% of the total sales. Industrial customers represent 0.3% of the total customers yet represent 35% of the total sales. Commercial customers account for 11% of total customers and represent 24% of sales. Figure D-2 below illustrates the customer and sales breakdown for 2023.

Figure D-2: Duke Energy Indiana Customer Landscape



Residential

The Residential class sales forecast comprises two projections: (1) the number of residential customers, which is driven by population; and (2) energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices, and appliance efficiencies.

The residential usage per customer forecast was derived using a Statistically Adjusted End-Use ("SAE") model. This is a regression-based framework that uses projected appliance saturation, structural characteristics, and efficiency trends at the end-use level (Heating, Cooling, Ventilation, Lighting, Cooking, Water Heating, and Miscellaneous) developed by Itron using Energy Information Administration ("EIA") data. It incorporates naturally occurring energy efficiency, electrification trends, and government mandates more explicitly than standard regression models, combining them with data on economic variables and weather to estimate how demand for energy would change over time as these factors change. The outlook for usage per customer via the end uses is relatively flat in the early forecast horizon due to competing labor-saving electrification and efficiency trends, with increasing growth in the later period attributed to the rise in electrification, particularly the increasing growth in EV energy after 2030. Increases in the number of customers also cause demand for energy to rise throughout the forecast period. The latter force is driven by population growth, so it is not delayed in its impact on the forecast in the same way as EV-driven sales.

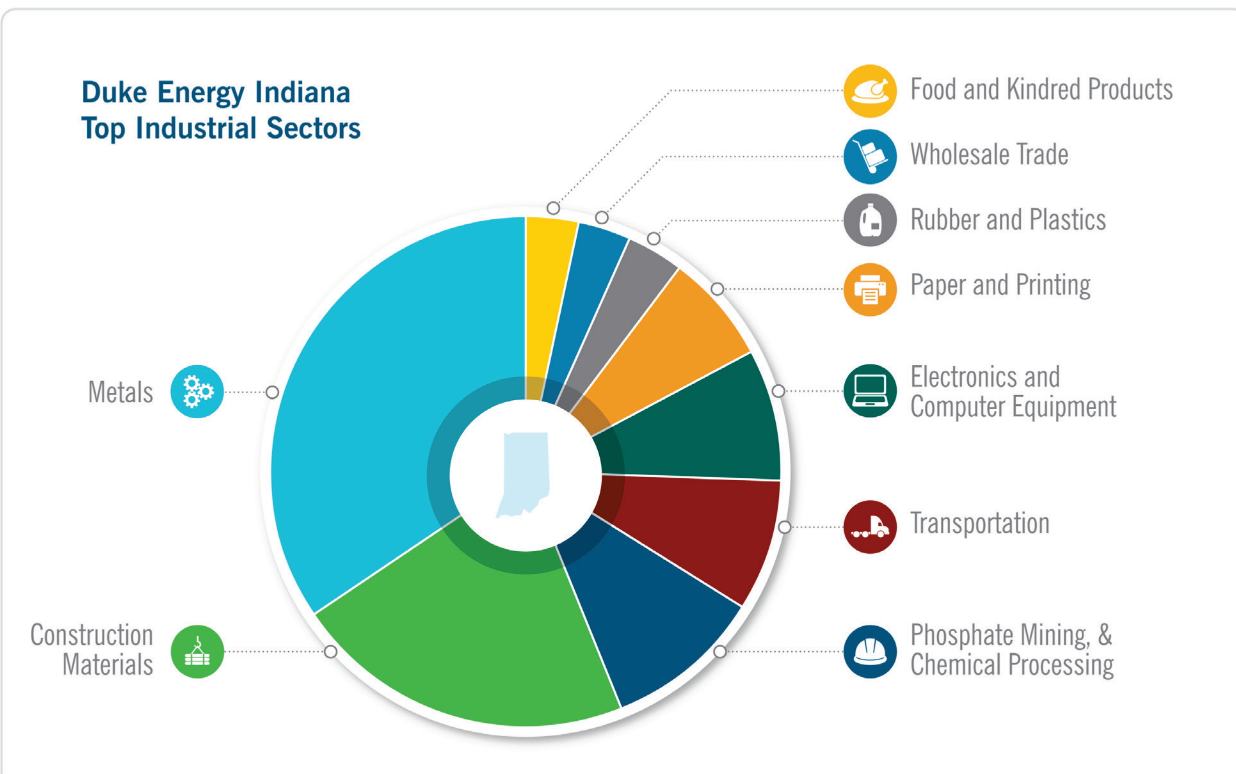
Commercial

The Commercial forecast, which predicts aggregate energy demand, also uses an SAE model, which models at the end-use level, similar to the residential sector (by building type), to reflect naturally occurring and government-mandated efficiency changes and labor-saving electrification trends and energy price-driven changes in electric fuel share of the commercial market. The three largest building type sectors in the commercial class are offices, education, and retail. Other sectors include public assembly, lodging, dining establishments, warehouses, hospitals, medical offices, and groceries.

Industrial

The Duke Energy Indiana service area comprises a diverse landscape of industrial sectors as shown in Figure D-3 below. Each of these industrial sectors can vary in electric intensity (megawatt-hours ("MWh") / Real Gross Domestic Product ("GDP")), growth opportunities, labor cost and savings potential, and many other important factors. With numerous different customer types, the industrial sector provides attractive economic development opportunities, which further stimulates growth in the industrial sector for Duke Energy Indiana.

Figure D-3: Duke Energy Indiana Current Industrial Customer Landscape



Total energy from the industrial class is forecasted by a standard econometric model. The econometric model has drivers such as total manufacturing output and the price of electricity. EIA uses a process model for the industrial class which captures rapid consumption changes due to efficiency gains, electrification, fuel price changes, and co-generation process changes. This industrial class forecast referred to the EIA industrial forecast for confirmation of the Duke Energy Indiana forecast.

Government

The Company uses the term Other Public Authorities ("OPA" or "Government") to indicate retail customers involved and/or affiliated with federal, state or local government. The Government class comprises sales to facilities such as public schools, government buildings, and water pumping stations. The Government monthly sales forecast is developed using a linear regression model and is most significantly driven by government employment and weather variables.

Street Lighting

The street lighting (or "outdoor lighting") forecast is developed using a separate linear regression model that trends historical street lighting usage and forecasts those sales into the future. Street lighting is the smallest retail sales class, comprising approximately 0.3% of energy sales, and is largely driven by the seasonal duration of dusk to dawn.

Wholesale

Wholesale hourly load and monthly sales are provided by the Wholesale Analytics group based on the existing contracts of Duke Energy Indiana with wholesale customers through 2030. For 2031 to 2044, the contract volumes for 2030 are assumed to continue through the forecast horizon.

Key Variables

Weather

Weather impacts are incorporated into the models by using a weather normal data set which involves beginning with average daily temperatures over the last 30 years, using the Indianapolis, Indiana, weather station data. Average daily weather temperatures are ranked from lowest to highest for winter months November to March and highest to lowest for summer months April to October. This ranking is performed for each of the 30 years. The rankings for each month across the last 30 years are averaged to determine the average value for a normal weather data set. Through this process there is an average daily temperature for each rank for each month for a normal weather calculation. The rank method using the 30 years of history is an electric industry standard for long-term planning. This method captures all weather temperature ranges and latency impacts of temperature patterns, allowing for contingency planning for electric resource planning.

The weather normal data is used to provide the values of heating degree days and cooling degree days. For the monthly SAE energy models, heating degree days is the sum of average daily temperature degrees below the base temperature, and cooling degree days is the sum of average daily temperature degrees above the base temperature. The cooling degree days measure is an independent variable driving cooling load, and the heating degree days measure is an independent variable driving heating load. The forecast of degree days is based on a 30-year average and updated annually.

Other Key Variables & Survey

The appliance saturation, efficiency, housing size and structure efficiency, fuel shares by end-use trends, and electric intensity per end use developed by Itron are based on underlying data from the EIA. These appliance trends are used to calculate end-use variables that constitute the independent variables in the residential sales regression models. The output variables from the Itron model which serve as the independent variables in the Duke Energy Indiana sales regression model include heating, cooling, and other electric demand per household. These variables along with other independent variables make up the regression model for residential use per customer. This calculation is performed by interacting the end uses with data on weather, economics, and effective price, such that the independent variables allow variation in energy sales to be exposed to variation across all key factors via a time series linear model.

The energy intensities utilized in the residential model (kwh / household) and the commercial sector model (kwh / square foot by building type) from Itron for the Midwest are calibrated to the Duke Energy Indiana service area based on the market saturation survey data available and sales for the base year. Electric energy intensity by end-use is a function of electric share of the end-use market in the Duke Energy Indiana service area and electric energy efficiency for the Duke Energy Indiana service area. Other factors in energy usage addressed in the survey and utilized in the Itron model include vintage and size of home, smart equipment in home, electronic devices, and other equipment used for entertainment. The Duke Energy 2022 Residential End-Use Appliance Study was utilized in the calibrating process of the East North Central Itron SAE data to the residential Duke Energy Indiana service area sales. The final Itron results for intensity are utilized in the calculation of the cooling, heating, and other end-use variables in the regression model for residential sales of Duke Energy Indiana. All these end-use components contribute to the usage per customer. The energy intensity and usage per customer is a function of fuel share, equipment efficiency, and home structure variables.

Calibration is calculated based on observed usage per customer versus the calculated usage per customer based on EIA data for the East North Central region of the United States, insights from the 2022 Saturation Survey, and testing of the model elasticities related to heating, cooling, and other Itron-calculated variable coefficients and elasticities after calibrated variables are applied to Itron. The calibration adjusts for differences between the Duke Energy Indiana service area residential sector and the East North Central regional EIA statistics supplied by Itron.

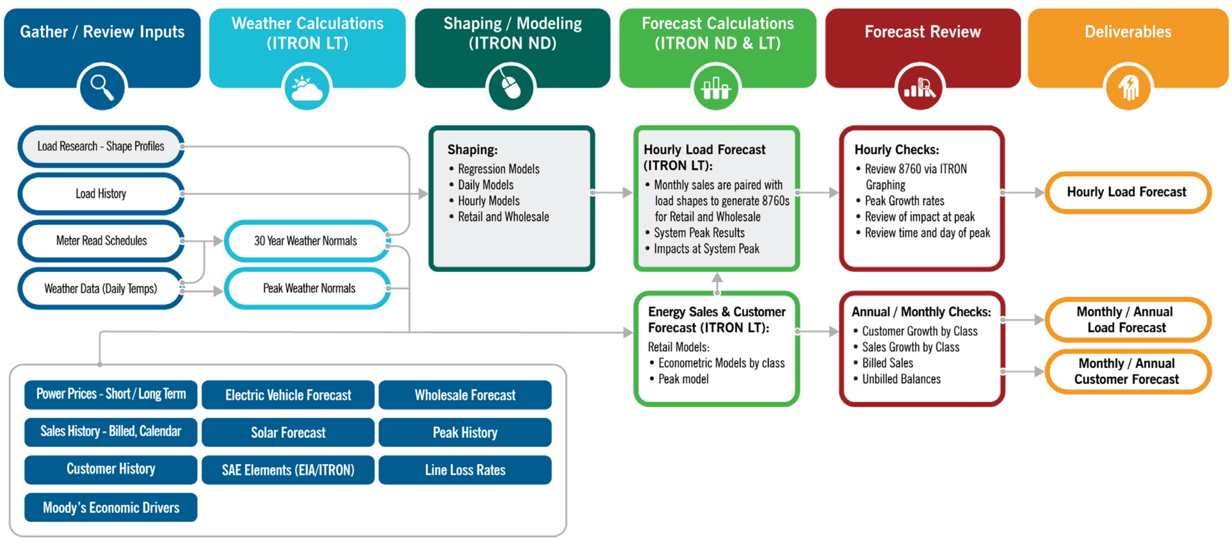
The extent to which Duke Energy Indiana programs motivating energy savings affect future demand for energy is treated separately from these saturation/efficiency considerations and deducted from the load forecast afterwards. See Appendix H (Demand-Side Resources & Customer Programs) and Appendix C (Quantitative Analysis) for detail on how energy efficiency is treated as a selectable demand-side resource in the 2024 IRP modeling.

Load Forecast Process & Enhancements

Forecast Process

Duke Energy Indiana continues to follow a forecast process in line with practices that date back to at least 2013. Much of this process is described in the surrounding text, and Figure D-4 below gives an overview of the workflow with some specific details given special attention immediately following.

Figure D-4: Load Forecasting Process



Duke Energy Indiana began using the SAE model projections to forecast sales and peaks in 2013. The end-use models provide a better platform to recognize long-term trends in equipment and appliance saturation, changes to efficiencies and how those trends interact with heating, cooling, and non-weather-related sales. These appliance trends are used in the residential and commercial sales models. In conjunction with peer utilities and Itron, the Company continually looks for refinements to its modeling procedures to make better use of the forecasting tools and develop more reliable forecasts.

Each time the forecast is updated, the most currently available historical and projected data is used. The forecast presented herein utilizes:

- Moody's Analytics January 2024 base and consensus economic projections.
- End-use equipment and appliance indices that reflect the 2023 update of Itron's end-use data, which is consistent with EIA's 2022 Annual Energy Outlook.[1]
- A calculation of normal weather using the period 1994-2023.

[1] EIA did not publish an Annual Energy Outlook in 2023.

The Company also researches weather sensitivity of summer and winter peaks, peak history, hourly shaping of sales, and load research data in a continuous effort to improve forecast accuracy. The scenario work described herein is fruit of that research, which is ongoing. Historical peaks and forecasted peaks are presented later in this Appendix as well.

A recovery from industrial recession, moderate growth in commercial and residential sectors, and a significant boost from economic development is in the base case forecast. Nevertheless, the economic inputs are varied as part of the analysis to produce economic high and low scenarios with a focus on the long-term planning horizon. The focus is on using economic differences to examine via scenario analysis and how the system responds to economic growth that significantly underperforms (or outperforms) expectations over the 20-year planning horizon.

Scenarios can also be examined by varying post-estimation adjustments, such as behind-the-meter solar generation, EV electric demand, economic development assumptions, and electrification to industrial industries. The results of these scenarios are presented later in this Appendix.

Peak Demand Calculation

Peak demands are projected using the SAE approach and reflect an adjustment for the mix of end uses at time of peak. The peak forecast was developed using a monthly SAE model, like the sales SAE models, which includes monthly appliance saturations and efficiencies, interactions with weather and the fraction of each appliance type that is in use at the time of monthly peak.

Forecast Enhancements

Every forecast cycle, the load forecasting team evaluates the regression models and makes changes to the independent variables used to forecast the dependent variables. Load forecasting continues to use the Itron SAE model, which leverages end-use analysis with the regression models. Available historical data is used to produce a robust forecast. Therefore, each year the training data size increases as more historical data is available. The training data now spans before, during, and after the COVID period which has improved the forecast outlook. The result of the increased training data has improved the reliability and robustness of the forecast models.

The load research sample qualities have improved with Advanced Metering Infrastructure ("AMI") data being made available to the load forecasting team, which improves the customer class hourly load shapes. The AMI data has also been incorporated into analytical report platforms, such as Power BI, and allows for retail sales analysis and industry studies to better understand recent history and the drivers of near-term sales history. This enhanced the model development, forecast assessment, and scenario crafting process.

With increasing economic development in Duke Energy Indiana and the impacts it has to load forecast, additional focus has been placed on coordination between the economic development team, large account management team, and load forecasting team. Through this coordination, the load forecast is adjusted to reflect the significant impact of future economic development efforts, assigning probabilities to economic development outcomes for scenario development, and taking the embedded growth in the regression model driven forecast into account. Additional detail on this process is provided later in this Appendix.

Load Forecast Drivers & Assumptions

Key Economic Drivers

Table D-1 below lists the projected average annual growth rates of several key economic drivers that are relevant when constructing the load forecast. These statistics characterize a region with consistent and durable long-term growth.

Table D-1: Summary of Annualized Compound Growth Rates of Key Economic Drivers

Driver	2025-2034 CAGR	2025-2044 CAGR
Households (Population)	0.60%	0.42%
Real Median Income	0.93%	1.01%
Real GDP Non-Manufacturing	2.23%	0.34%
Real GDP Manufacturing	2.09%	1.74%
Residential Electric Rates	-4.26%	-1.394%
Commercial Electric Rates	-3.72%	-0.851%
Industrial Electric Rates	-5.67%	-2.787%
Government Electric Rates	-5.08%	-2.298%
Economic Development Projects Energy Growth	9.53%	8.28%

Note: Growth in electric rates is based on 2023 dollars (adjusted for inflation).

As with previous editions of the forecast, the economic data is combined with price, weather, and end-use data to form SAE terms (representing heating, cooling and base load end uses) for residential and commercial sales models. Models for other categories of customers, such as industrial, government or street lighting, do not interact with the end-use data, but rather are treated as separate terms for estimation. These calculations have been performed to prepare the independent variables so that model estimation can be carried out. Table D-2 below provides information on the structure for key estimation models in the Company's forecast, including the economic drivers used for each major estimation equation. Table D-2 also indicates models that are part of an SAE structure as opposed to a conventional time series estimation.

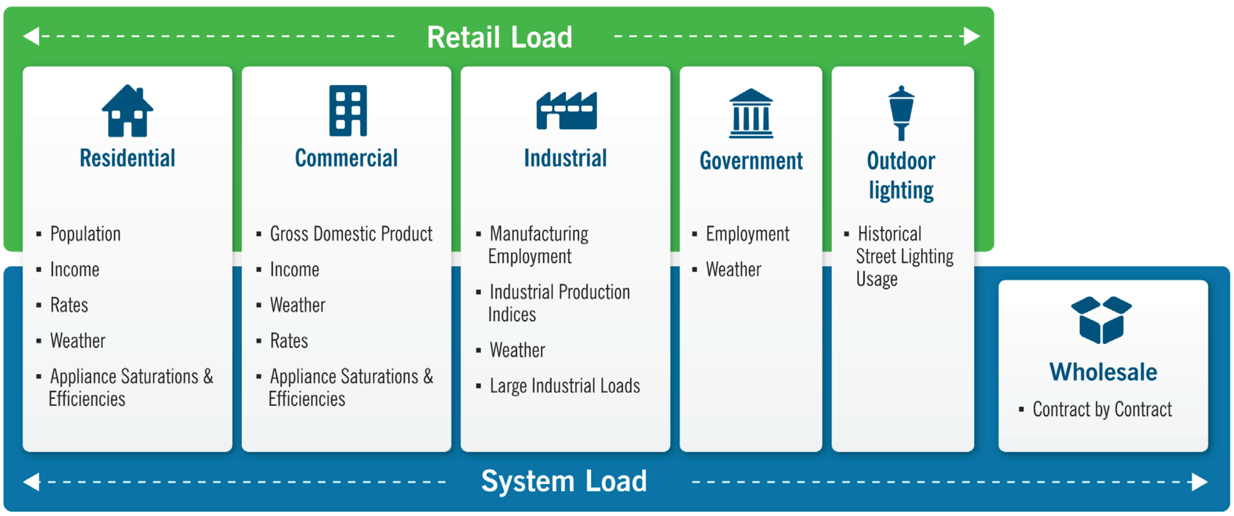
Table D-2: Description of Estimation Models

Dependent Variables	SAE Modeling	Weather Drivers	Economic Drivers
Customer Count (Residential)	N	N	- Households (Population)
Use Per Customer (Residential)	Y	Heating and Cooling Degree Days	- Real Median Income per Household - Persons per Household - Electricity Price (Real) - EIA End-Use Intensity
Commercial Sales	Y	Heating and Cooling Degree Days	- Electricity Price (Real) - EIA End-Use Intensity
Commercial Customers	N	N	- Residential Customers
Industrial Sales	N	Cooling Degree Days	- Log of Interactive Term: Manufacturing Employment & Real GDP, after indexing to 2018
OPA/Government Sales	N	Heating and Cooling Degree Days	- Government Employment

Drivers by Customer Class

The load forecast is developed through a bottom-up approach looking at the various customer classes. As discussed previously, each customer class is unique with varying energy needs and usage patterns. The primary forecast drivers for the customer classes are shown below in Figure D-5.

Figure D-5: Primary Forecast Drivers by Customer Class



Residential Drivers

The following key driver variables are input into the SAE model to develop the forecasted residential usage per customer:

- **Population**: Population and household data is provided by Moody's Analytics. It has a significant positive relationship with customer count and therefore residential sales.
- **Income**: Average household income is gathered from Moody's Analytics and is adjusted for inflation. It has a significant positive relationship with residential usage per customer and therefore residential sales.
- **Rates**: Average residential rates are gathered by Duke Energy Indiana and forecasted by Duke Energy Indiana with adjustments for inflation, provided by Moody's Analytics. It has a significant negative relationship with residential usage per customer and therefore residential sales.
- **Weather**: Weather data is provided by National Oceanic and Atmospheric Administration ("NOAA") and is reflected as heating degree day and cooling degree day variables derived by Duke Energy under normalized weather assumptions.
- **Appliance Saturations and Efficiencies**: Appliance saturation and efficiency data is provided EIA, then adjusted by Itron and the Duke Energy Indiana load forecasting analysts to reflect

current appliance saturations and future efficiency gains by appliances driven by market technology and governmental policies. The usage intensity derived from all components of the data has a significant positive relationship with usage per customer. Note that efficiency gains, driven by market driven technology gains and government policies, have a negative relationship with usage per customer. Electrification trends are driven by labor-saving technology trends and government policies.

In addition to the SAE model developing a forecasted usage per customer, a regression model is used to forecast the number of residential customers, based on historical and forecasted household data which is provided by Moody's. The final residential sales forecast is developed by combining the usage per customer with the total number of customers forecast.

Commercial Drivers

The following key driver variables are input into the SAE model to develop the forecasted commercial class sales:

- **Gross Domestic Product**: Non-manufacturing GDP adjusted for inflation is provided by Moody's Analytics.
- **Income**: Average household income is gathered from Moody's Analytics and is adjusted for inflation.
- **Weather**: Weather data is provided by NOAA and is reflected as heating degree day and cooling degree day variables derived by Duke Energy Indiana under normalized weather assumptions.
- **Rates**: Average commercial rates are gathered by Duke Energy and forecasted and adjusted for inflation
- **Appliance Saturations and Efficiencies**: These are provided by the EIA then adjusted by Itron and the Duke Energy Indiana load forecasting analysts to reflect current appliance saturations and future efficiency gains by appliances driven by market technology and governmental policies. Note that efficiency gains, driven by market-driven technology gains and government policies, have a negative relationship with usage per customer. Electrification trends are driven by labor-saving technology trends and government policies.

An additional regression model is used to model the total number of commercial customers. The number of commercial customers is based on historical customer commercial counts and forecasted based on growth rates of residential customer counts.

Industrial Drivers

The following key driver variables are used in the standard regression modeling of industrial sales:

- **Manufacturing Employment**: The number of manufacturing employees by sectors for Indiana is provided by Moody's Analytics.

- **Industrial Production Indices**: The monetary industrial output value of industrial sectors for Indiana, provided by Moody's Analytics.
- **Weather**: Weather data is provided by NOAA and is reflected as heating degree day and cooling degree day variables derived by Duke Energy Indiana under normalized weather assumptions.

In addition to the variables above, large customer loads are analyzed and added separately based on history and known future activity which are provided by large customer account and economic development managers.

Government Drivers

The following key driver variables are used in the standard regression modeling of government sales:

- **Employment**: The number of government employees in Indiana are provided by Moody's Analytics.
- **Weather**: Weather data is provided by NOAA and is reflected as heating degree day and cooling degree day variables derived by Duke Energy Indiana under normalized weather assumptions.

The linear regression model was estimated with OPA monthly sales as the dependent variable and government employment as the primary independent variable along with the independent weather variables of heating degree days and cooling degree days. All variables were highly significant with P statistic values below 2%, indicating the probability that the coefficients for the independent variables in the regression equations are not statistically significant is less than 2%. Government employment drives most of the growth with an elasticity of demand of 0.9. Weather is also a significant driver with weather elasticities of demand of 0.02 for winter and 0.09 for summer. Electric demand would be most sensitive to summer weather versus winter weather because electricity is the only energy source for cooling appliances while the heating load may be served by electricity and/or natural gas.

Street Lighting Drivers

Street lighting retail class monthly sales are modeled using a separate linear regression model fitted using monthly historical data from 2015 to 2023, with street lighting monthly sales as the dependent variable and a log trend variable as the primary independent variable. With 102 observations, all four variables were significant with P values below 0.4%. The demand elasticity of the trend variable was 1.0. The street lighting demand is not weather sensitive as it is driven by the seasonal cycle of the number of hours between sundown and sunrise.

Wholesale Drivers

Existing wholesale contract data is utilized to prepare the hourly load and monthly sales forecast for the wholesale class.

Statistically Adjusted End-Use Measures & Energy Efficiency

In the load forecast prepared for the 2024 IRP, only expiring impacts of adopted Utility Energy Efficiency ("UEE") programs, referred to as roll-off UEE, and naturally occurring EE, driven by the market forces, are included in the load forecast. Additional UEE is modeled as a selectable resource and explained in further detail in Appendix H (Demand-Side Resources & Customer Programs).

Naturally occurring energy efficiency ("EE") recognizes load reductions resulting from customers adopting efficiency measures that are not the direct result of a Duke Energy Indiana approved program. These efficiency gains are included within the latent forecast variables via the described SAE procedure; this data from the EIA is distributed by Itron via the SAE package and used as predictors for the forecasting model estimation. Naturally occurring EE is important to acknowledge and quantify, because it has a dampening impact on the load growth. Although the economy, energy prices, and government tax policies promoting energy efficiency will continue to dampen growth, there still will be growth in the load forecast due to labor-saving technological changes, real per capital income growth, electrification, growth in households, and commercial and industrial real GDP growth.

Customer Growth

Tables D-3 and D-4 below show the history and projected number of customers; each major customer class is estimated using the statistical methods described above. The historical retail customer compound annual growth rate ("CAGR") over the period 2005 to 2023 is 0.91% for Duke Energy Indiana, while projected retail customer growth for the period 2023 to 2044, Table D-4, is 0.77%.

The main driver for retail customer growth is the residential sector, which is driven by household population growth. The components of population growth are the natural increase, births minus deaths, and net migration into the Duke Energy Indiana service area. Net migrations from other states to Duke Energy Indiana service area have been significant from 2021 to 2023 and will continue through the next four years at a declining rate. Industrial growth will drive most of the net migration along with the low cost of housing, tax-friendly environment, logistic hubs, and technology clusters.

Table D-3: Historical Customer Counts

Year	Residential Customers	Commercial Customers	Industrial Customers	Government Customers	Street Lighting Customers	Total Retail Customers
2005	659,371	86,310	2,907	9,414	989	758,991
2006	665,227	87,575	2,884	9,445	1,097	766,228
2007	671,839	88,687	2,868	9,471	1,188	774,053
2008	673,432	89,552	2,845	9,587	1,263	776,679
2009	672,841	89,436	2,815	9,863	1,406	776,361
2010	677,590	89,555	2,790	10,122	1,458	781,514
2011	678,931	89,493	2,754	10,302	1,399	782,878
2012	683,335	89,861	2,734	10,259	1,433	787,621
2013	688,302	89,973	2,726	10,282	1,473	792,756
2014	693,513	90,117	2,708	10,235	1,514	798,085
2015	710,737	90,381	2,707	10,220	1,574	815,619
2016	717,907	90,688	2,721	10,181	1,615	823,111
2017	724,767	91,018	2,718	10,145	1,664	830,312
2018	732,757	93,604	2,721	9,547	3,841	842,470
2019	742,540	93,924	2,692	9,568	3,892	852,615
2020	751,396	94,417	2,697	9,541	3,954	862,006
2021	760,746	94,782	2,668	9,483	3,980	871,659
2022	771,796	95,746	2,662	9,379	3,986	883,568
2023	781,957	96,401	2,648	9,248	3,905	894,158
2005-2023 CAGR	0.95%	0.62%	-0.52%	-0.10%	7.93%	0.91%

Table D-4: Projected Customer Counts

Year	Residential Customers	Commercial Customers	Industrial Customers	Government Customers	Street Lighting Customers	Total Retail Customers
2025	802,892	97,687	2,672	9,323	4,183	916,758
2026	813,982	98,373	2,681	9,370	4,241	928,646
2027	824,171	99,018	2,685	9,390	4,294	939,558
2028	833,837	99,636	2,687	9,399	4,344	949,903
2029	843,230	100,238	2,688	9,403	4,393	959,952
2030	852,359	100,823	2,689	9,404	4,441	969,716
2031	861,153	101,387	2,689	9,405	4,486	979,120
2032	869,568	101,927	2,689	9,405	4,530	988,119
2033	877,301	102,423	2,690	9,405	4,571	996,389
2034	884,090	102,858	2,690	9,406	4,606	1,003,649
2035	890,473	103,268	2,690	9,406	4,639	1,010,474
2036	896,431	103,650	2,690	9,406	4,670	1,016,846
2037	901,732	103,990	2,690	9,406	4,698	1,022,515
2038	906,485	104,295	2,690	9,406	4,723	1,027,598
2039	910,921	104,579	2,690	9,406	4,746	1,032,341
2040	915,052	104,844	2,690	9,406	4,767	1,036,758
2041	918,575	105,070	2,690	9,406	4,786	1,040,526
2042	921,691	105,270	2,690	9,406	4,802	1,043,858
2043	924,448	105,447	2,690	9,406	4,816	1,046,806
2044	927,016	105,612	2,690	9,406	4,830	1,049,552
2025-2044 CAGR	0.76%	0.41%	0.03%	0.05%	0.76%	0.71%

Adjustments for Economic Development Activity

Duke Energy Indiana devotes resources to promoting and enabling the long-term flourishing of the region, including attracting new industries and businesses to the area and partnering with these incoming companies to plan for their energy needs as they connect with employees and customers. Aligning with the activities in this space requires consideration of economic development results, particularly when efforts to attract these investments have a substantial impact on the forecast. However, a tension exists – the very same economic data to which load forecast models are exposed predict a healthy economy which should include many new investments and site openings (as well as the closings that are a natural part of regional economic churn). When the load forecasting team receives a list of potential economic site openings and closings, a screening process is followed to adjust the load forecast, dependent on project maturity and a sizing threshold of 20 MW. Several of the largest potential projects were used to adjust the forecast this cycle, although the size of the adjustment (in both MWh and megawatts (“MW”)) was scaled down from full weight to reflect both the uncertain, future-oriented nature of the plans and recognize that a portion of the economic development activity may be imbedded in the economic forecast provided by Moody's. Conversely, if recent trends in significant economic development expansion in the Duke Energy Indiana service area persist, the Company will continue to reflect such increased activity in future load forecasts as well as future resource planning cycles. This will be a particular focus area for future forecasts given the dynamic nature of many macro variables impacting large economic development potential in Indiana. Such macro variables include but are not limited to, continuing population growth through in-migration to the region, EV adoption rates and supporting infrastructure needs for the electric auto industry, trends toward onshoring of global manufacturing in response to geopolitical uncertainty, rate of growth in data computing needs to support rapid expansion of infrastructure for cloud computing, artificial intelligence, and cryptocurrency, photovoltaics production requirement in the U.S., domestic battery industry success in the future, supplier response to these economic expansions, commercial growth supporting the manufacturing industry expansion, and the impact of future state and federal policies to either promote or inhibit economic expansion in Indiana, to name just a few.

To stay abreast of these uncertainties, Duke Energy Indiana’s Economic Development and Large Account Management teams continually devote resources toward tracking and engaging with a series of potential development projects at various stages of consideration or buildout, with many of these submitted for consideration to the load forecasting team. Ultimately, the team elevated several of these projects – those large enough in magnitude with plans sufficiently advanced such that the demand could be anticipated with a high degree of certainty – into a rarified group used to adjust the load forecast beyond what would have occurred only based on the calculations from the economic and other independent predictors. Consideration may also be given to a site that might be suddenly closing (i.e., withdrawing demand from the system) if that site meets similar criteria. Table D-5 below lists the adjustments applied to the annual forecast based on these “Large Site Adjustments.”

Combining such calculations with the results of an econometric model introduces a possibility of some double counting to the extent that economic forces motivate the individual site adjustments. To mitigate the impact of a possible “double count,” the load forecasting team adjusts the forecasted economic development additions based on the insights and experience of the Economic Development and Large Account Management teams, resulting in a reduced amount of the full load expectation. In the 2024 base load forecast, this consideration equates to a discount of approximately 40%.

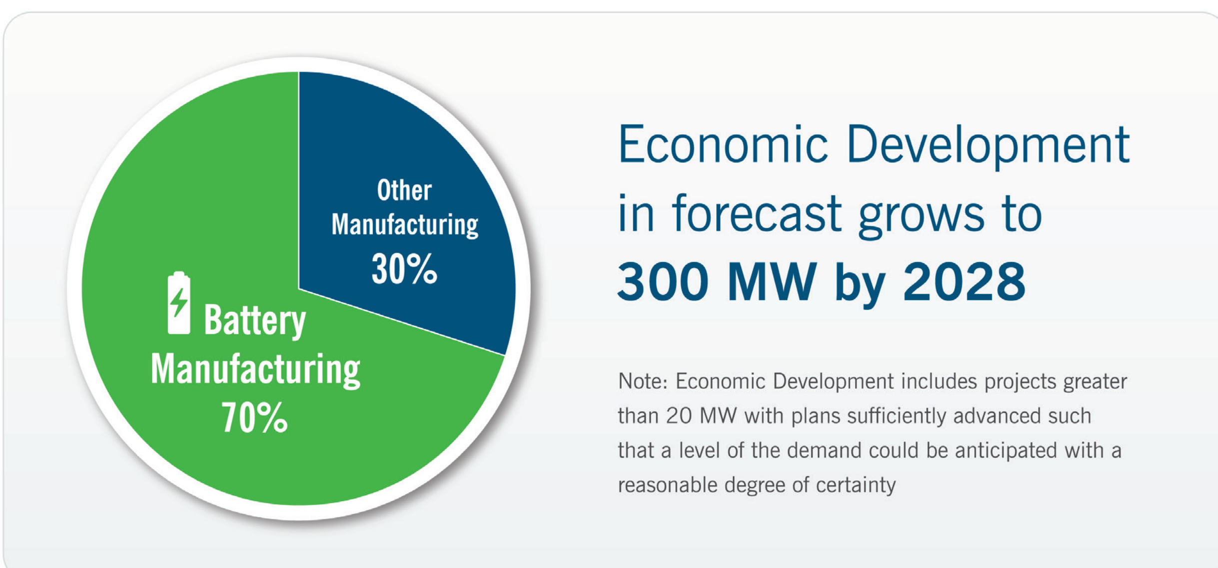
Notably, the forecast adjustment for economic development does not include supplier jobs or induced jobs created by the sizable investments that may accompany the economic development adjustments for the base case and the low case, which are further discussed in this Appendix in the alternative scenarios section. The high case will have adjustments for the supplier jobs and the induced jobs that may occur due to the economic development activity, adding load to the high load forecasts.

Table D-5: Adjustments in the Base Load Forecast for Large Site Developments

Year	Adjustment (MWh)
2024	399
2025	917
2026	1,538
2027	2,055
2028	2,087
2029-2044	2,081

In summary, the size, scale, and speed of economic development projects has dramatically increased recently, such that a greater proportion of the portfolio is above the threshold where an explicit addition to the forecast is appropriate. Duke Energy Indiana has played a critical role in partnering with local and state economic development entities to ensure the successful recruitment of these highly competitive mega-projects to the Duke Energy Indiana service area. The Company has seen specific success in the emerging EV sector, including battery production and associated supply chain activities, alongside other industries such as steel production, solar cells, and traditional manufacturing. Figure D-6 below highlights battery manufacturing as a significant share of economic development through 2030.

Figure D-6: Economic Development Projects in Base Load Forecast



Behind-the-Meter Solar Forecast & Assumptions

The BTM solar forecast is a modifier to the load forecast, acting as a reduction to the load. The forecasts are developed for residential, commercial, and industrial segments at an hourly level.

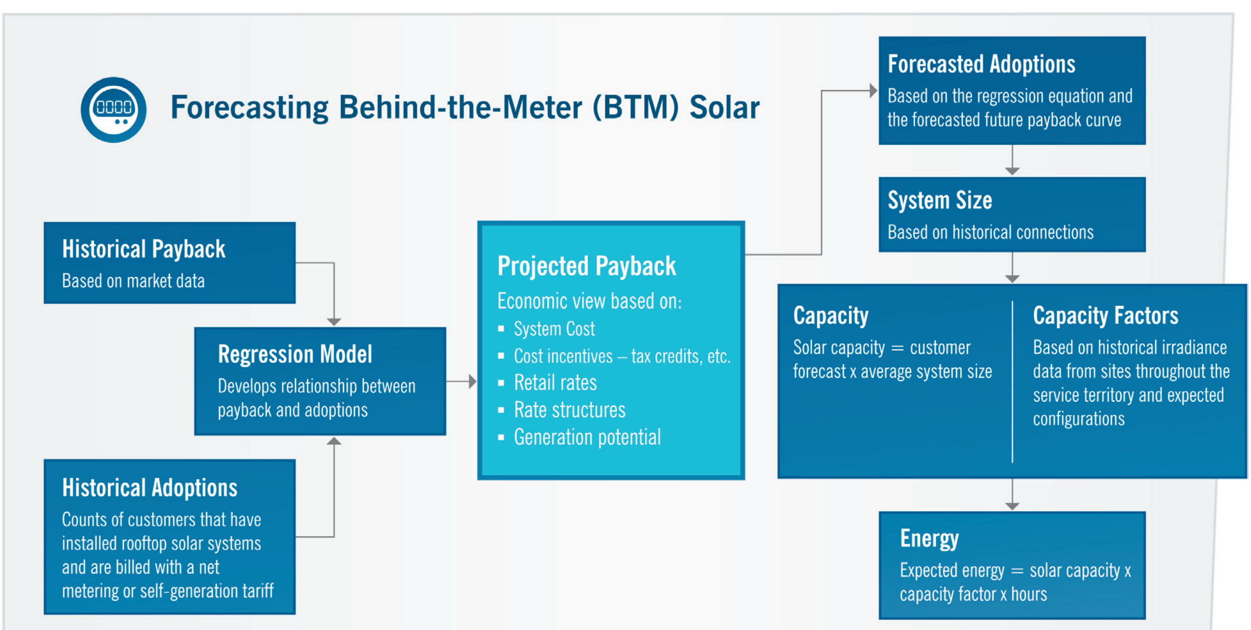
The BTM forecasting process uses regression modeling techniques to estimate the relationship between adoptions (installations) and payback. Historical data is used to determine the relationship, and the resulting regression equation and future payback projections are used to estimate forward adoptions. The number of adoptions is converted to capacity using historical size estimates, and the capacity is converted into energy estimates by applying hourly production profiles. The hourly energy data is the adjustment to the load forecast.

Along with the development of the regression model, projections of future payback are key components of the forecast. The primary inputs to the payback model include system cost, incentives, rates, and capacity factors. The system cost data is sourced from Guidehouse. Starting with the cost projections from Guidehouse and applying known incentives such as the Inflation Reduction Act of 2022, federal investment tax credit ("ITC") yields an estimated base installation cost. Bill savings are then determined based on rates and rate structures as well as expected generation. The payback is calculated as the time required for the monthly bill savings to offset the initial cost of the system.

The hourly production profiles are derived from photovoltaic ("PV") modeling using PVSyst software. Historical irradiance data from five locations within the Duke Energy Indiana service territory is collected and analyzed using a combination of 21 different tilt and azimuth configurations, with the results weighted to produce profiles for both residential and non-residential systems.

Figure D-7 below provides a visual view of the process flow, key inputs, and calculations for forecasting BTM solar.

Figure D-7: BTM Solar Forecasting Process Overview



Historical Adoption

The number of behind-the-meter resource connections among Duke Energy Indiana customers has been steadily increasing, with an average annual growth rate of around 30% over the past five years. By the end of 2023, about 0.5% of Duke Energy Indiana's residential customers had installed solar panels or solar systems paired with storage. Figures D-8 and D-9 below present historical adoption and capacity data for BTM solar in Duke Energy Indiana.

Figure D-8: Historical BTM Solar Adoption

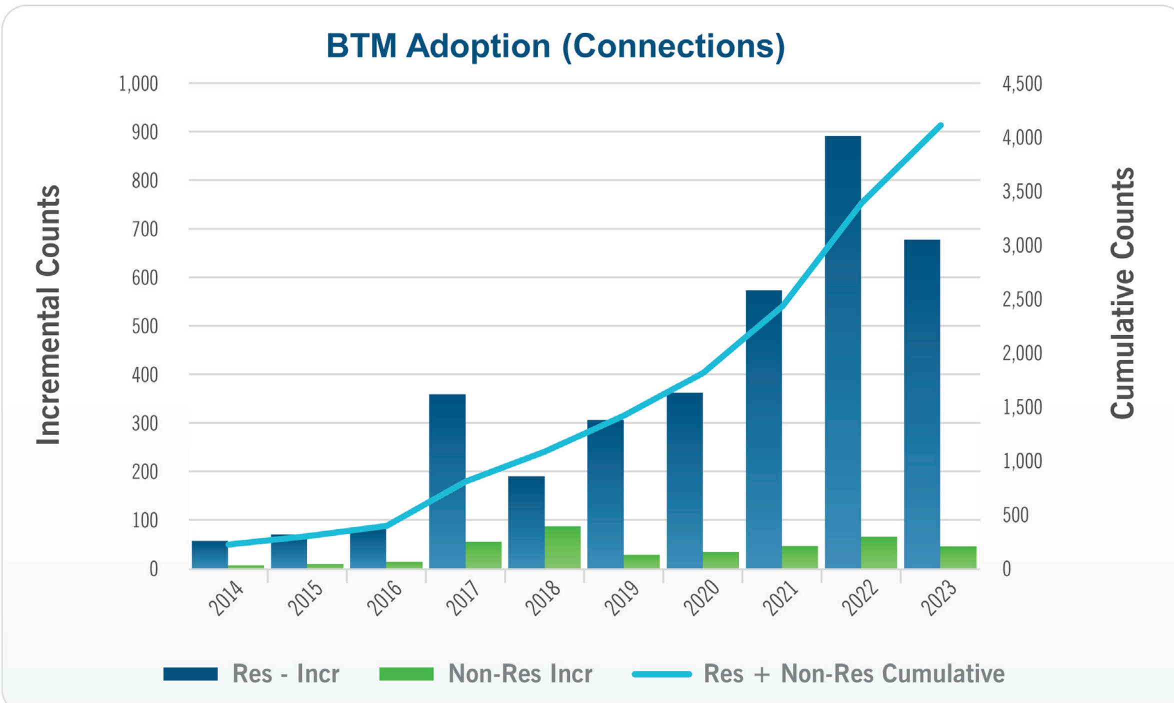
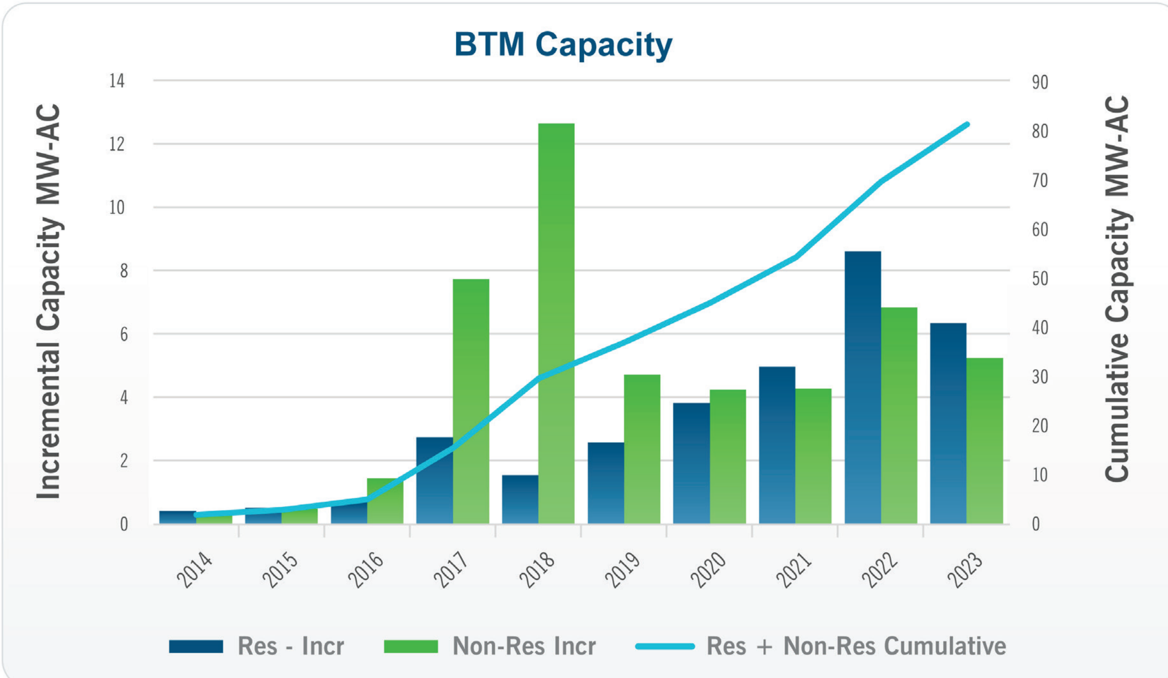


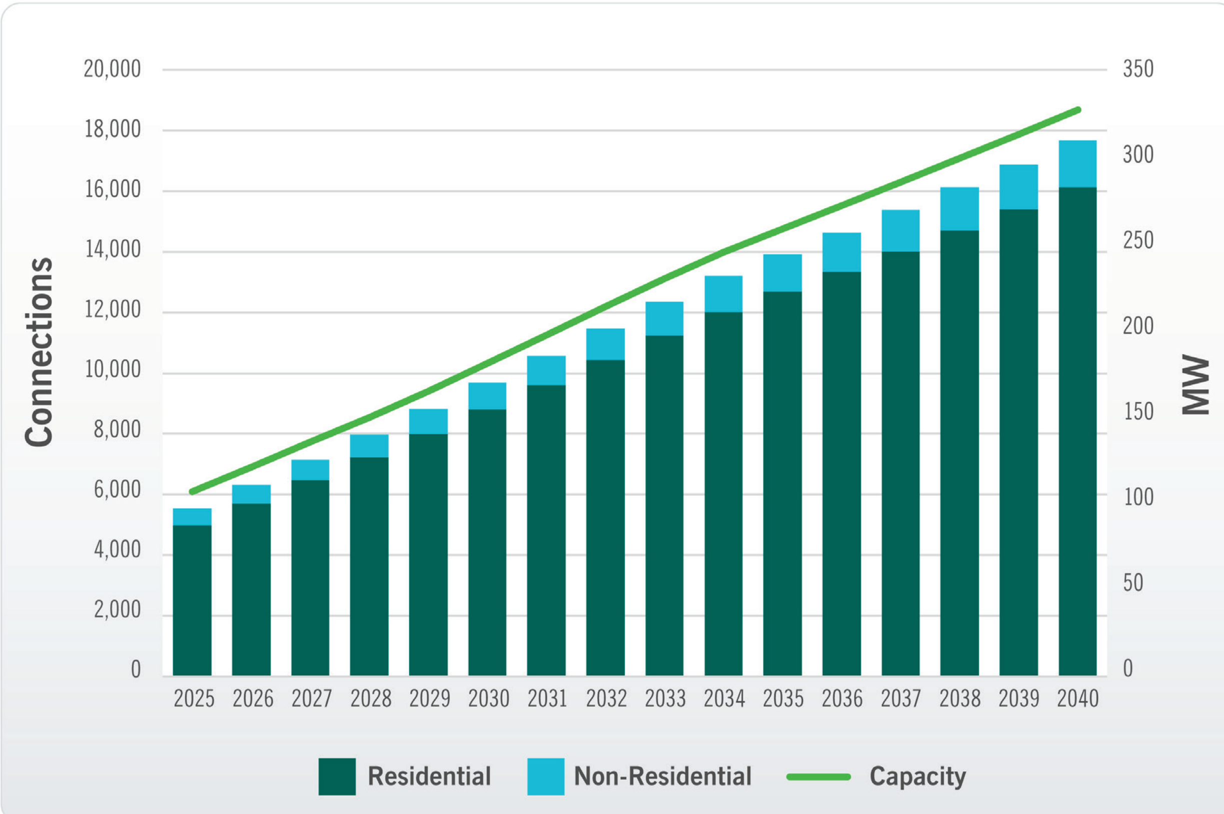
Figure B-9: Historical BTM Solar Incremental and Cumulative Capacity



Base Behind-the-Meter Solar Forecast

BTM solar adoption is anticipated to grow annually at a rate of roughly 10% over the next decade, reaching a total of 1.5% of customers in 2034. Figure D-10 below shows the forecasted BTM solar adoption and associated capacity for Duke Energy Indiana customers.

Figure D-10: Forecasted BTM Solar Adoption & Capacity



Alternate Behind-the-Meter Forecasts

In addition to the base BTM forecast, high and low BTM forecasts were developed to capture a range of BTM adoption possibilities, which were utilized as key inputs to the alternate system load forecast scenarios discussed later in this Appendix. The high and low BTM forecasts were created by adjusting the payback model variables of system costs and ITC credits. In the high BTM forecast, lower system costs and enhanced ITC credits were assumed, resulting in increased BTM adoption. In the low BTM forecast, higher system costs and ITC credits were removed resulting in decreased BTM adoption. These forecasts were utilized to develop the alternate load forecast scenarios discussed later in this Appendix. Table D-6 below details the assumptions used to inform the low, base, and high BTM forecasts and shows the resulting impacts to BTM penetration in 2030 and 2040. The annual forecasted impact to total system load of the base, high, and low BTM forecasts is presented later in this Appendix alongside the forecasted impacts of EVs and economic development.

Table D-6: Low, Base, and High BTM Forecast Assumptions and Resulting Impacts

Dependent Variables	Low	Base	High
Key Assumption Differences	• Payback model adjustments • High PV system costs • Removal of ITC credits	Base Case	• Payback model adjustments • Low PV system costs • Enhanced ITC credits
% of Residential Customers in 2024	0.5%	0.5%	0.6%
% of Residential Customers in 2030	0.7%	1.0%	1.3%
% of Residential Customers in 2040	1.3%	1.8%	2.3%

Economic considerations significantly influence the adoption rates of BTM resources. Consequently, elements that affect the financial aspects of BTM resources will serve as crucial facilitators or barriers. Duke Energy Indiana will continue to monitor system costs, incentives, interest rates, inflation rates, borrowing rates, and other market dynamics that are anticipated to influence the economic framework of BTM resources so that future forecasts can be adjusted to reflect changing market conditions.

Electric Vehicle Forecast & Assumptions

The transportation industry is undergoing an unprecedented transition to EVs from traditional internal combustion engine vehicles. In 2023, ~7.5% of new vehicles sold in the U.S. were electric, compared to ~5.9% in 2022 and ~3.2% in 2021.[2] This adoption trend is expected to continue and accelerate, especially considering federal initiatives, automaker goals, and the federal goal to have EVs make up at least 50% of new vehicle sales by 2030. This transition to EVs will require diligent planning and forecasting to provide the energy required to charge the EVs while maintaining grid reliability. In addition to the EV forecasting methodology outlined below, Duke Energy Indiana is continuing to monitor and evaluate EV load management and managed charging pilots and programs which will provide additional insights when forecasting EV charging characteristics.

Duke Energy Indiana develops its EV load forecast by using the Guidehouse Vehicle Analytics and Simulation Tool (“VAST”). The tool first develops a vehicle forecast using a total cost of ownership calculation based on multiple historical and forecasted parameters such as vehicle registrations (Information Handling Services Markit), vehicle manufacturer’s suggested retail price (“MSRP”) values (Guidehouse Insights), battery efficiency characteristics (Argonne National Lab), projections of fuel costs (from EIA and Automotive Association of America), future vehicle availability, and vehicle miles traveled (from Federal Highway Administration). These variables, along with others, help determine

[2] Cox Automotive, A Record 1.2 Million EVs Were Sold in the U.S. in 2023, According to Estimates from Kelley Blue Book, January 9, 2024, available at https://www.coxautoinc.com/market-insights/q4-2023-ev-sales/.

the total cost of ownership of a vehicle, which is used in the development of forecasted vehicle adoption.

Once the vehicle adoption forecast is created, the associated energy and load are forecasted. Variables to determine energy, such as vehicle miles traveled and vehicle efficiency, can be used to calculate charging energy requirements for the vehicles. Then the associated load charging profiles are derived from public, private, and third-party analysis (such as the National Renewable Energy Laboratory ("NREL") EVI-Pro tool and Guidehouse Insights). These charging profiles are broken down by three duties: light, medium and heavy. Based on the adoption forecast, the projected amount of energy needed to charge the EVs, the hourly EV demand profiles, and the EV hourly 8760 load forecast are developed. All three duties are calculated using similar methodology and make up the EV load forecast that is added to the Duke Energy Indiana load forecast.

Figure D-11 below illustrates the inputs and variables used in the VAST model. Tables D-7 and D-8 below provide additional detail on the VAST model inputs and data sources.

Figure D-11: VAST Model Overview

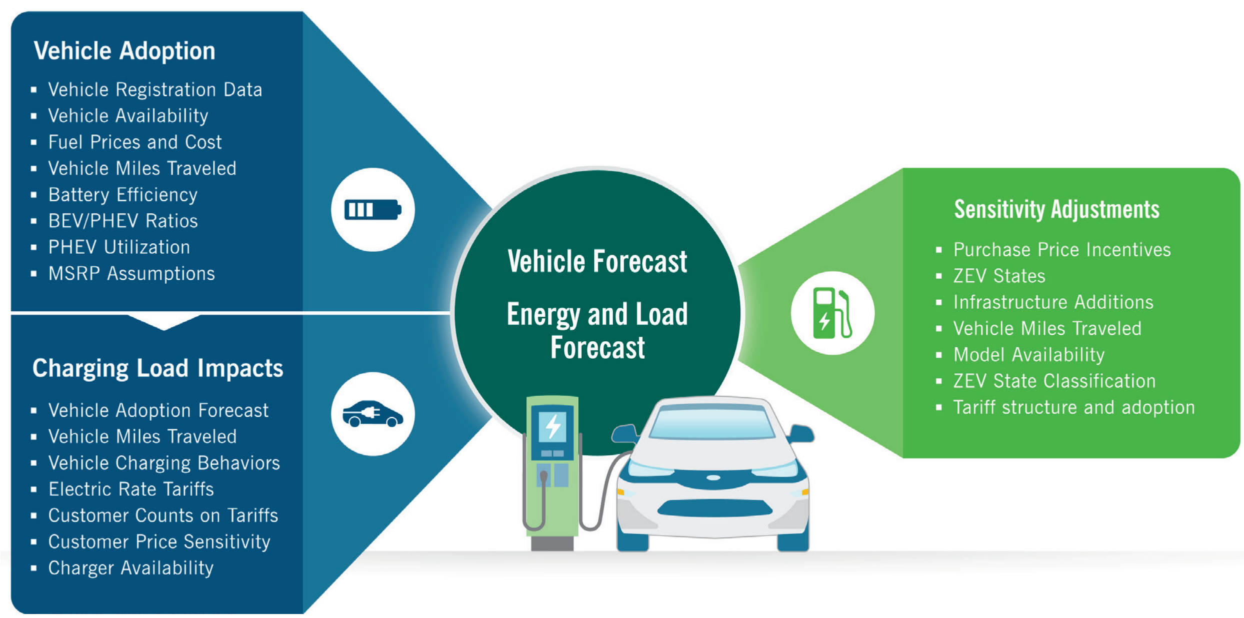


Table D-7: VAST Model Inputs for Vehicle Adoption Forecast

Vehicle Adoption		
Inputs	**Description**	**Source**
Vehicle Registration Data	US vehicle registration by make, model, and year at the ZIP code	Information Handling Services Markit
Vehicle Availability	Future availability of EV and Internal Combustion Engine ("ICE") models	Guidehouse Subject Matter Expert ("SME") Insights
Fuel Costs	Electricity rates ($/kwh) and gasoline and diesel prices ($/gal)	Energy Information Administration (electricity) American Automobile Association (gasoline and diesel)
Vehicle Miles Traveled	Forecasted annual vehicle miles traveled	Federal Highway Administration
Vehicle Efficiency	kWh/mile forecast	Argonne National Lab Guidehouse SME Insights
Battery EVs ("BEV")/ Plug-in Hybrid EV ("PHEV") Ratios	Registered percentages of Battery Electric vs. Plug-in Hybrid Electric	Information Handling Services Markit
PHEV Utilization	PHEV miles proportion using the battery	Argonne National Lab
MRSP Assumptions	Total MSRP vehicle cost for vehicles	International Council on Clean Transportation Guidehouse SME Insights

Table D-8: VAST Model Inputs for Charging Load Impacts Forecast

Charging Load Impacts		
Inputs	**Description**	**Source**
Vehicle Adoption Forecast	Number of BEVs and PHEVs forecasted by year	Vehicle Adoption Module
Vehicle Miles Traveled	Forecasted annual vehicle miles traveled	Federal Highway Administration
Vehicle Charging Load Shapes	Typical hourly charging behavior by vehicle type	NREL's Electric Vehicle Infrastructure – Projection tool (EVI-Pro)
Electric Tariff Rates	Electric rates and demand charges	Duke Energy Indiana
Customer Counts on Tariffs	Proportion of customers on Time-of-Use (“TOU”) vs non-TOU rates	Duke Energy Indiana
Customer Price Sensitivity	Sensitivity of customers to energy and demand prices regarding electric vehicle charging	Guidehouse SMEs - Empirical literature analysis
Vehicle per Charger Ratios	Current, long-run, and interpolated ratios of chargers needed to support number of EVs	Alternative Fuel Data Center (current) NREL’s EVI-Pro (long-run)

Base Electric Vehicle Forecast

Figures D-12 and D-13 below present the base EV forecasting, showing the forecasted electric vehicles in operation and associated load by vehicle class in the Duke Energy Indiana service territory through 2040.

Figure D-12: Forecasted Electric Vehicles in Operation by Vehicle Class

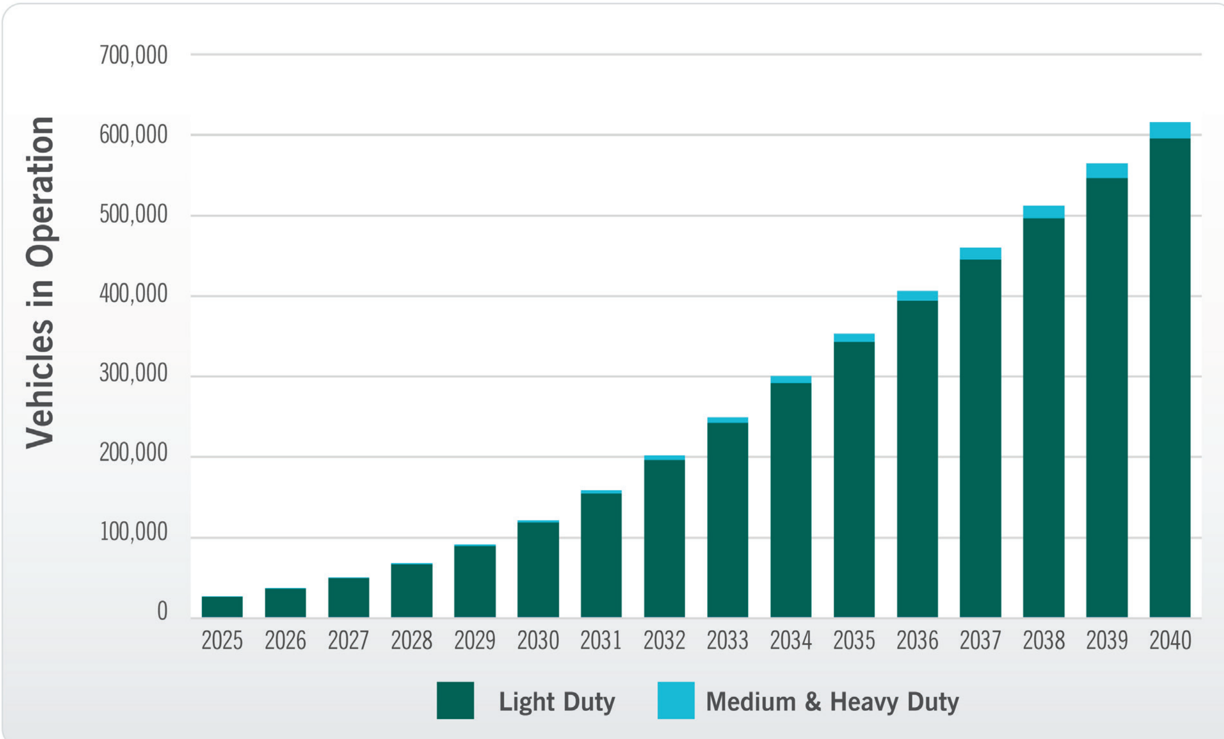
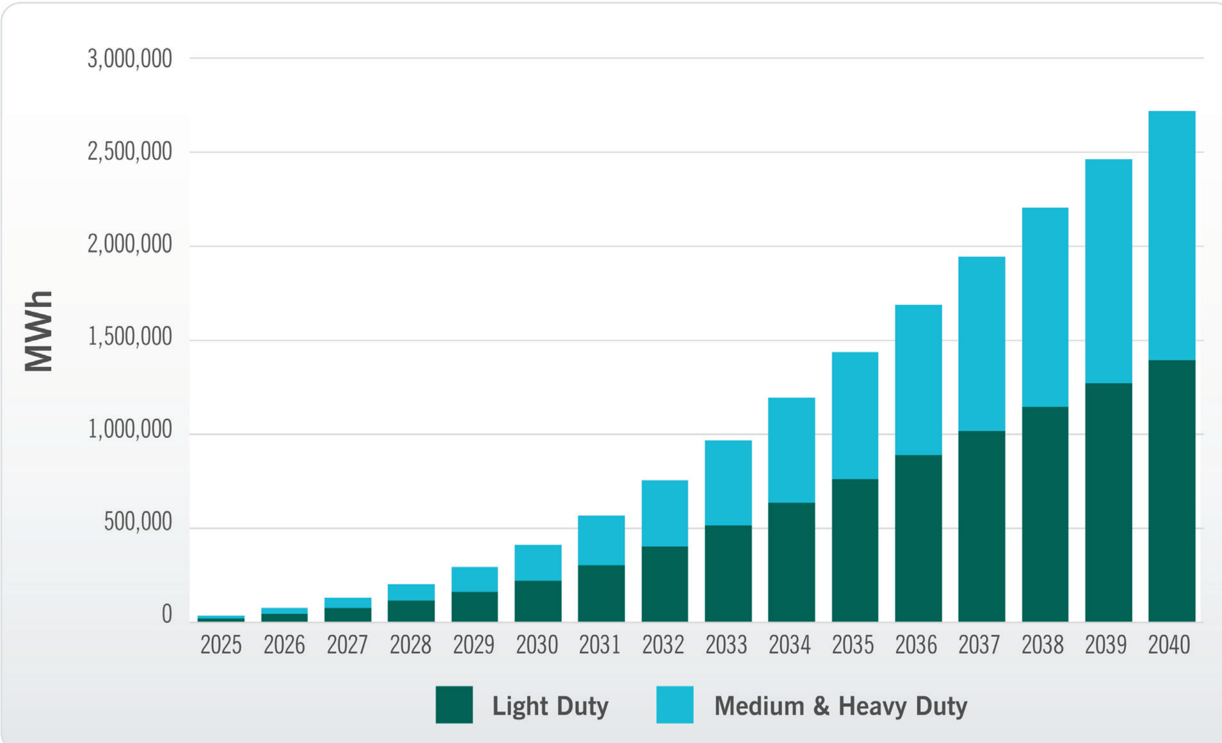


Figure D-13: Forecasted Electric Vehicle Load by Vehicle Class in Duke Energy Indiana



Alternate Electric Vehicle Forecasts

In addition to the base EV forecast, high and low EV forecasts were developed to capture a broad range of EV adoption possibilities, which were utilized as key inputs to the alternate system load forecast scenarios discussed later in this Appendix. The high and low EV forecasts were created by adjusting the forecasted MSRP costs of EVs, the number of EV models available to purchase, and the consumer preference towards EVs relative to traditional internal combustion engine vehicles. Table D-9 below details the assumptions used to inform the low, base, and high EV forecasts and shows the resulting impacts to EV penetration in 2030 and 2040. The annual forecasted impact to total system load of the base, high, and low EV forecasts is presented later in this Appendix alongside the forecasted impacts of BTM solar and economic development.

Table D-9: Low, Base, and High EV Forecast Assumptions and Resulting Impacts

Dependent Variables	Low	Base	High
Key Assumption Differences	• Higher EV Cost (~5% increase in MSRP) • Lower EV availability and increased ICE availability • Lower consumer preference for EVs	Base Case	• Lower EV Cost (~5% decrease in MSRP) • Higher EV availability and decreased ICE availability • Higher consumer preference for EVs
% of New Vehicle Sales in 2030	24%	38%	52%
% of Vehicles on the Road in 2030	5%	7%	10%
% of Vehicles on the Road in 2040	19%	33%	38%
Total Energy (GWh) in 2030	330	413	659
Total Energy (GWh) in 2040	2,001	2,720	3,515

Notably, the EV forecast shows a considerable increase in adoption relative to the 2021 IRP due to the trends discussed above. The base EV forecast for the 2024 IRP projects that EVs will make up 38% of new vehicle sales in 2030 compared to 11% in the 2021 IRP.

Forecast Results & Commentary

Historical & Projected Load Forecast Information

Tables D-10 through D-15 below provide historical and projected load forecast information pertaining to customers and energy sales. Tables D-10 through D-15 provide CAGR information.

Table D-10: Historical Actual Retail Sales by Class (MWh)

Year	Residential	Commercial	Industrial	Government	Street Lighting	Total Retail
2005	9,046,541	5,907,692	11,641,145	2,188,816	53,374	28,837,567
2006	8,632,975	5,892,465	11,715,647	2,207,944	53,846	28,502,877
2007	9,428,221	6,310,050	11,553,630	2,325,866	53,953	29,671,719
2008	9,312,774	6,273,817	10,806,921	2,285,127	54,226	28,732,867
2009	8,884,340	6,006,647	9,028,798	2,258,174	54,198	26,232,155
2010	9,648,417	6,218,804	10,096,981	2,253,794	53,877	28,271,880
2011	9,181,818	6,135,339	10,167,403	2,193,103	53,602	27,731,264
2012	8,941,016	6,173,469	10,448,829	2,170,271	53,181	27,786,765
2013	9,232,328	6,203,404	10,448,873	2,171,289	52,839	28,108,730
2014	9,285,421	6,196,833	10,643,015	2,163,369	52,835	28,341,474
2015	8,924,185	6,244,537	10,505,308	2,094,028	52,899	27,820,955
2016	9,036,013	6,322,074	10,564,695	2,083,007	52,596	28,058,379
2017	8,644,837	6,145,935	10,598,736	2,054,449	52,457	27,496,413
2018	9,550,113	6,340,543	10,607,299	2,080,749	51,966	28,630,668
2019	9,246,749	6,207,728	10,326,793	2,004,334	51,280	27,836,885
2020	9,081,656	5,771,047	9,573,579	1,846,227	50,706	26,323,220
2021	9,169,934	6,013,838	9,769,133	1,935,833	50,076	26,938,819
2022	9,437,092	6,364,838	9,534,797	1,893,076	60,111	27,289,914
2023	8,610,814	6,228,067	8,895,566	1,819,591	64,848	25,618,887
2005-2023 Growth	-435,727	320,375	-2,745,579	-369,225	11,474	-3,218,680
2005-2023 CAGR	-0.27%	0.29%	-1.48%	-1.02%	1.09%	-0.66%

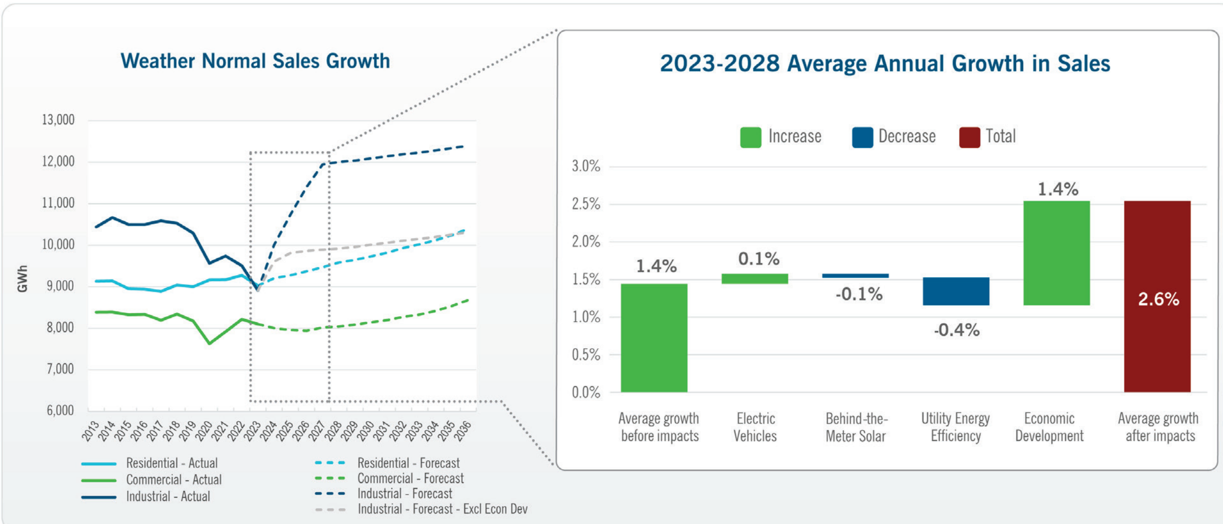
Table D-11 below shows the retail sales forecasts across customer classes. Total retail sales are forecasted to grow from 2025 to 2044 at a compound annual growth rate of 1.2%. The industrial class is anticipated to grow at a CAGR of 1.0%, which is driven by industries located in the Duke Energy Indiana service area and the expansion of industrial activity due to economic development. The commercial sector is anticipated to grow at a CAGR of 1.7%, increasing annual sales by 2,260,140 MWh throughout the time horizon. Residential sales growth, driven by increased population to the service area and the low-cost environment of the service area has a CAGR of 1.3%. The government and street lighting classes also will grow moderately with the residential and the commercial and industrial activity.

Table D-11: Forecasted Retail Sales by Class (MWh)

Year	Residential	Commercial	Industrial	Government	Street Lighting	Total Retail
2025	9,407,046	6,204,294	10,748,893	1,875,819	61,448	28,297,499
2026	9,543,398	6,258,305	11,430,681	1,877,645	62,177	29,172,206
2027	9,684,306	6,404,782	11,987,780	1,883,378	62,878	30,023,124
2028	9,843,723	6,489,309	12,056,072	1,893,915	63,555	30,346,573
2029	9,950,712	6,581,127	12,101,545	1,906,242	64,208	30,603,833
2030	10,082,364	6,688,912	12,161,946	1,917,200	64,839	30,915,262
2031	10,217,168	6,786,491	12,218,997	1,925,276	65,450	31,213,382
2032	10,374,786	6,904,294	12,276,805	1,931,255	66,042	31,553,182
2033	10,495,965	6,996,293	12,323,589	1,935,380	66,616	31,817,843
2034	10,629,605	7,112,204	12,379,075	1,938,370	67,173	32,126,427
2035	10,771,109	7,239,479	12,435,248	1,939,127	67,715	32,452,678
2036	10,943,655	7,391,272	12,495,187	1,938,717	68,241	32,837,071
2037	11,058,882	7,512,908	12,546,060	1,938,920	68,753	33,125,522
2038	11,197,854	7,658,570	12,607,372	1,940,843	69,251	33,473,891
2039	11,336,614	7,804,090	12,675,055	1,944,189	69,737	33,829,684
2040	11,494,496	7,969,158	12,748,979	1,949,549	70,211	34,232,393
2041	11,566,020	8,060,624	12,803,650	1,954,510	70,673	34,455,477
2042	11,676,666	8,182,332	12,866,752	1,959,197	71,124	34,756,072
2043	11,798,977	8,317,248	12,932,967	1,963,648	71,565	35,084,404
2044	11,965,007	8,483,582	13,009,034	1,967,461	71,995	35,497,080
2025-2044 Growth	2,557,962	2,279,289	2,260,140	91,643	10,547	7,199,580
2025-2044 CAGR	1.27%	1.66%	1.01%	0.25%	0.84%	1.20%

Figure D-14 below illustrates the main near-term sales growth drivers impacting the forecast, with UEE included, over the next years. Economic development has the greatest impact on the five-year growth from 2023 to 2028. This impact reflects growth beyond what is anticipated from the existing commercial and industrial activity and the growth in the commercial and industrial sectors currently served by Duke Energy Indiana. The growth of the existing industrial base and the new base created by economic development is illustrated by the gray and dark blue dashed lines. Although the 2024 IRP forecast does not include the full impact of UEE (only the roll off portion of UEE is included in the IRP), it does provide an illustration of the willingness of customers to adopt program efficiency investments. Electric vehicles and behind-the-meter solar generation have small offsetting impacts on the forecast over the near-term. EVs begin to more significantly impact the forecast in the early 2030s (see Figure D-13 above).

Figure D-14: Near-Term Sales Growth Drivers



Tables D-12 and D-13 below illustrate the historic and forecasted total system generation and system peaks, along with residential, commercial, and industrial contributions to the total system generation. System generation CAGR increases from -0.26% over history (2013-2023) to 1.02% over the forecast period (2025 to 2044). The decline in growth rate of the peak relative to the increase in growth in energy is due to the strong growth in the industrial and commercial sectors relative to the residential sector. The higher load factors in industrial and commercial relative to residential load factor result in growth in the system generation load factor of 6.75% (2025 to 2044).

Table D-12: Historical Actual System Peak, Generation, and Load Factor

Year	System Peak (MW)	Total System Generation (MWh)	Load Factor
2013	5,703	31,567,683	63.19%
2014	5,728	32,696,951	65.16%
2015	5,807	33,226,985	65.31%
2016	6,165	34,138,499	63.04%
2017	5,699	32,112,787	64.33%
2018	5,795	33,282,230	65.56%
2019	5,876	31,732,228	61.65%
2020	5,746	30,450,488	60.33%
2021	5,952	31,328,230	60.09%
2022	5,938	31,896,082	61.32%
2023	5,930	29,499,157	56.79%
2013-2023 Growth	227	-2,068,527	-0.89%
2013-2023 CAGR	0.26%	-0.68%	-1.72%

Table D-13: Forecasted System Peak, Generation, and Load Factor

Year	System Peak (MW)	Total System Generation (MWh)	Load Factor
2025	5,972	33,093,386	63.26%
2026	5,893	33,499,448	64.89%
2027	5,917	34,446,812	66.46%
2028	5,924	34,916,046	67.10%
2029	5,934	34,807,030	66.96%
2030	5,945	35,214,848	67.62%
2031	5,956	35,536,896	68.11%
2032	5,970	35,903,970	68.47%
2033	5,989	36,189,874	68.98%
2034	6,010	36,523,227	69.38%
2035	6,034	36,875,663	69.77%
2036	6,059	37,290,909	70.07%

2037	6,087	37,602,512	70.51%
2038	6,150	37,978,843	70.50%
2039	6,221	38,363,193	70.40%
2040	6,292	38,798,225	70.20%
2041	6,344	39,039,215	70.25%
2042	6,401	39,363,937	70.20%
2043	6,462	39,718,622	70.16%
2044	6,530	40,164,421	70.02%
2025-2044 Growth	559	7,071,035	6.75%
2025-2044 CAGR	0.47%	1.02%	0.54%

Tables D-14 and D-15 below illustrate the differences in the summer and winter peak CAGRs of the last 11 years (2013-2023) and the forecast period (2025-2044). The summer peak CAGR from 2025-2044 is 0.39% compared to the winter peak CAGR of 0.85%. As electric vehicle adoption increases, winter peaks shift to the evenings due to charging load shapes and become a key driver for winter peak growth.

Table D-14: Historical Actual Annual and Seasonal System Peak (MW)

Year	Annual Peak	Summer Peak	Winter Peak
2013	5,703	5,703	5,218
2014	5,728	5,728	5,699
2015	5,807	5,807	5,666
2016	6,165	6,165	5,661
2017	5,699	5,699	5,320
2018	5,795	5,795	5,684
2019	5,876	5,788	5,876
2020	5,746	5,746	5,255
2021	5,952	5,952	5,150
2022	5,938	5,938	5,629
2023	5,930	5,930	4,777
2013-2023 Growth	227	226	-440
2013-2023 CAGR	0.39%	0.39%	-0.88%

Table D-15: Forecasted Annual and Seasonal System Peak (MW)

Year	Annual Peak	Summer Peak	Winter Peak
2025	5,972	5,972	5,563
2026	5,893	5,893	5,503
2027	5,917	5,917	5,550
2028	5,924	5,924	5,583
2029	5,934	5,934	5,612
2030	5,945	5,945	5,650
2031	5,956	5,956	5,696
2032	5,970	5,970	5,749
2033	5,989	5,989	5,807
2034	6,010	6,010	5,869
2035	6,034	6,034	5,937
2036	6,059	6,059	6,008
2037	6,087	6,087	6,078
2038	6,150	6,118	6,150
2039	6,221	6,150	6,221
2040	6,292	6,191	6,292
2041	6,344	6,247	6,344
2042	6,401	6,302	6,401
2043	6,462	6,370	6,462
2044	6,530	6,433	6,530
2025-2044 Growth	558	461	967
2025-2044 CAGR	0.47%	0.39%	0.85%

Table D-16 below shows the annual impacts of load modifiers on the base load forecast and provides a more detailed breakdown of total system load including base retail sales, net retail sales at meter, gross retail sales at generator, wholesale sales, and total system obligation at generator.

Table D-16: Forecasted Energy Sales – System Obligation at Generator (GWh)

Year	Base Retail Sales	Economic Dev.	UEE Historic Roll Off	Rooftop Solar	Electric Vehicles	Net Retail Sales at Meter	Line Loss + Company Use	Gross Retail at Generator	Wholesale	System Obligation at Generator
2025	27,350	917	20	-26	36	28,297	2,303	30,600	2,493	33,093
2026	27,565	1,538	37	-44	77	29,172	2,373	31,545	1,954	33,499
2027	27,845	2,055	55	-63	131	30,023	2,441	32,464	1,983	34,447
2028	28,068	2,087	71	-82	202	30,347	2,467	32,814	2,102	34,916

2029	28,245	2,081	86	-101	294	30,604	2,488	33,092	1,715	34,807
2030	28,452	2,081	92	-122	413	30,915	2,513	33,428	1,787	35,215
2031	28,616	2,081	90	-143	570	31,213	2,537	33,750	1,787	35,537
2032	28,801	2,081	79	-165	757	31,553	2,564	34,117	1,787	35,904
2033	28,893	2,081	63	-186	967	31,818	2,585	34,403	1,787	36,190
2034	29,013	2,081	44	-206	1,195	32,126	2,610	34,736	1,787	36,523
2035	29,131	2,081	28	-224	1,437	32,453	2,636	35,089	1,787	36,876
2036	29,295	2,081	14	-242	1,689	32,837	2,667	35,504	1,787	37,291
2037	29,351	2,081	6	-258	1,946	33,126	2,690	35,816	1,787	37,603
2038	29,462	2,081	2	-275	2,204	33,474	2,718	36,192	1,787	37,979
2039	29,579	2,081	0	-293	2,463	33,830	2,747	36,576	1,787	38,363
2040	29,742	2,081	0	-310	2,720	34,232	2,779	37,011	1,787	38,798
2041	29,800	2,081	0	-327	2,902	34,455	2,797	37,252	1,787	39,039
2042	29,915	2,081	0	-345	3,105	34,756	2,821	37,577	1,787	39,364
2043	30,043	2,081	0	-362	3,323	35,084	2,847	37,932	1,787	39,719
2044	30,234	2,081	0	-382	3,564	35,497	2,880	38,378	1,787	40,164
CAGR 2025-2034	0.7%	9.5%	9.2%	25.9%	47.6%	1.4%	1.4%	1.4%	-3.6%	1.1%
CAGR 2025-2044	0.5%	4.4%	—	15.2%	27.3%	1.2%	1.2%	1.2%	-1.7%	1.0%

Alternate Load Forecasts

Because the load forecast is sensitive to assumptions on economic growth, electric vehicle adoption, behind-the-meter solar adoption, and economic development, alternative load forecast scenarios were created to address these uncertainties. In the creation of alternative economic scenarios many variables varied including population, economic activity, demographics, customer usage, technology, all customer behavior factors affecting consumption, and state and federal policies. What remained fixed across the scenarios were the fuel price and the price elasticity parameters derived from the regression analysis. Electrification, beyond transportation, is assumed in Itron models throughout all scenarios and leverages EIA data. Table D-17 below illustrates the framework used to craft the alternate scenarios.

Table D-17: Base, High, and Low Load Forecast Assumptions

	Economics	Electric Vehicles	Behind-the-Meter Solar	Economic Development
Low	90/10	Low Adoption	High Adoption	Low (25%)
Base	50/50	Base Adoption	Base Adoption	Base (~60%)
High	10/90	High Adoption	Low Adoption	Higher (75%) +500 MW data center[1]

Note 1: 500 MW of data center load is assumed in the high case in addition to 75% of announced economic development projects.

Base Load Forecast

For the Base Load Forecast model runs, the economic forecast in the 50/50 case from Moody's is utilized, which reflects a forecast that has a 50% probability of not exceeding the economic outcome and a 50% probability that the forecast will exceed the economic outcome. The Base Load Forecast includes the most likely case for adoption of electric vehicles and the most likely case for adoption of behind-the-meter solar generation. For economic development, the Base Load Forecast assumes that approximately 60% of the announced economic development peak and energy additions come to fruition.

Low Load Forecast

For the Low Load Forecast model runs, the economic forecast in the 90/10 case from Moody's is utilized, which reflects a forecast that has a 90% probability of not exceeding the economic outcome and a 10% probability that the forecast will exceed the economic outcome. The Low Load Forecast includes the low case for adoption of electric vehicles and the high case for adoption of behind-the-meter solar generation. For economic development, the Low Load Forecast assumes that 25% of the announced economic development peak and energy additions come to fruition.

High Load Forecast

For the High Load Forecast model runs, the economic forecast in the 10/90 case from Moody's is utilized, which reflects a forecast that has a 10% probability of not exceeding the economic outcome and a 90% probability that the forecast will exceed the economic outcome. The High Load Forecast also includes the high case for adoption of electric vehicles and the low case for adoption of behind-the-meter solar generation. For economic development, the high case assumes that 75% of the announced economic development peak and energy additions come to fruition. Beyond the 75% of announced economic development projects, an additional 500 MW of data center load was added over five years (approximately 100 MW per year starting in 2027). Also, the economic development assumption is used to derive secondary employment created by the primary activity assumed in the economic development forecast, adding a boost to commercial and industrial electric sales.

Forecasted System Generation and Peak in Alternate Load Forecasts

Table D-18 below shows the total system annual net load across the forecast scenarios. Table D-19 below provides the annual winter and summer system peak for each forecast scenario.

Table D-18: Total System Net Load in Low, Base, and High Load Forecasts (MWh)

Year	Low	Base	High
2025	31,349,265	33,093,386	37,274,441
2026	31,496,814	33,499,448	38,321,848
2027	32,127,841	34,446,812	40,354,323
2028	32,561,002	34,916,046	41,880,522
2029	32,398,930	34,807,030	42,815,673
2030	32,682,107	35,214,848	44,186,137
2031	32,870,720	35,536,896	45,502,685
2032	33,064,511	35,903,970	46,002,913
2033	33,170,264	36,189,874	46,361,173
2034	33,288,967	36,523,227	46,763,762
2035	33,421,071	36,875,663	47,185,089
2036	33,613,955	37,290,909	47,694,707
2037	33,705,280	37,602,512	48,043,095
2038	33,851,655	37,978,843	48,469,285
2039	34,006,774	38,363,193	48,897,727
2040	34,203,995	38,798,225	49,384,919
2041	34,286,980	39,039,215	49,663,499
2042	34,426,157	39,363,937	50,054,443
2043	34,581,886	39,718,622	50,486,465
2044	34,800,178	40,164,421	51,044,350
2025-2044 Growth	3,450,913	7,071,035	13,769,909
2025-2044 CAGR	0.55%	1.02%	1.67%

Table D-19: Annual Winter and Summer Peak in Low, Base, and High Load Forecasts (MWh)

Year	Winter (MW)			Summer (MW)		
	Low	Base	High	Low	Base	High
2025	5,167	5,563	5,959	5,681	5,972	6,570
2026	5,100	5,503	5,949	5,596	5,893	6,556
2027	5,134	5,550	6,105	5,618	5,917	6,708
2028	5,162	5,583	6,278	5,629	5,924	6,845
2029	5,173	5,612	6,425	5,641	5,934	6,982
2030	5,188	5,650	6,584	5,649	5,945	7,117
2031	5,200	5,696	6,751	5,655	5,956	7,252
2032	5,216	5,749	6,829	5,656	5,969	7,289
2033	5,219	5,807	6,905	5,660	5,989	7,326
2034	5,227	5,869	6,990	5,660	6,010	7,353
2035	5,236	5,937	7,073	5,664	6,034	7,379
2036	5,253	6,008	7,164	5,671	6,059	7,410
2037	5,256	6,078	7,233	5,678	6,087	7,486
2038	5,267	6,150	7,311	5,687	6,118	7,572
2039	5,279	6,221	7,392	5,697	6,150	7,647
2040	5,298	6,292	7,479	5,708	6,191	7,721
2041	5,298	6,344	7,535	5,717	6,247	7,770
2042	5,305	6,401	7,604	5,726	6,302	7,853
2043	5,313	6,462	7,678	5,735	6,370	7,975
2044	5,330	6,530	7,767	5,748	6,433	8,067

Impact of Key Assumptions by Load Forecast Scenario

Figures D-15 to D-19 below illustrate the impact of economic development, EVs, and BTM solar across the load forecast scenarios. Figures D-18 and D-19 below provide the peak load and energy results of the load forecast demand scenario work. All data presented is specific to the Duke Energy Indiana service territory.

Figure D-15: Forecasted Economic Development Impact by Load Scenario

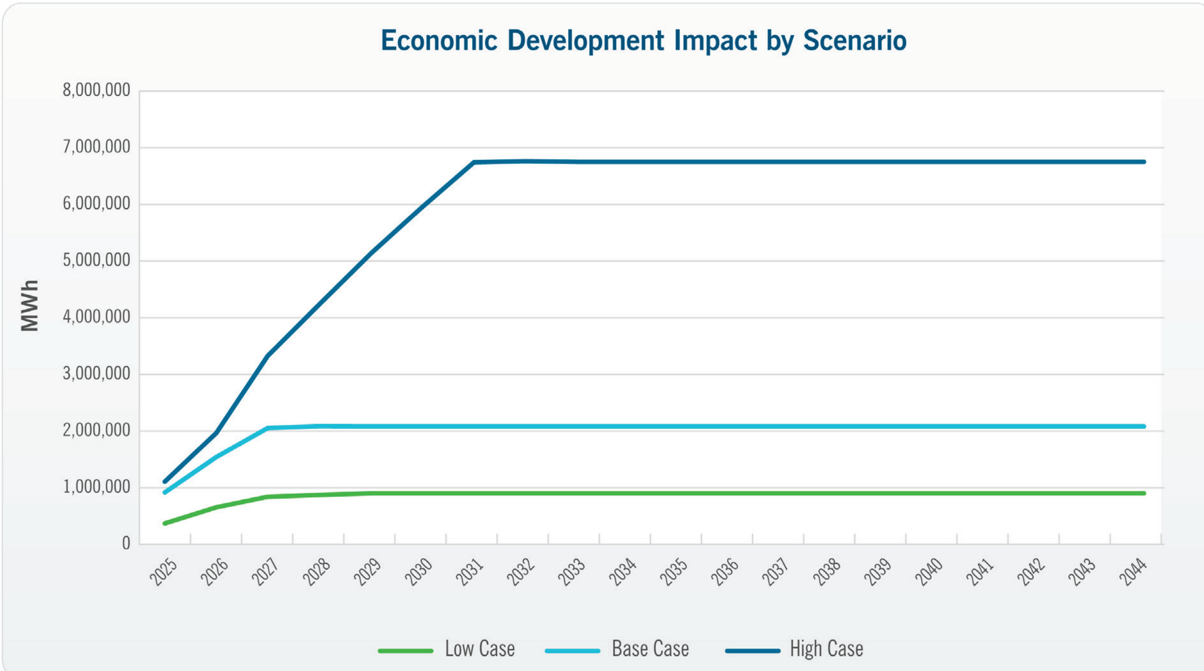


Figure D-16: Forecasted Electric Vehicle Load Impact by Load Scenario

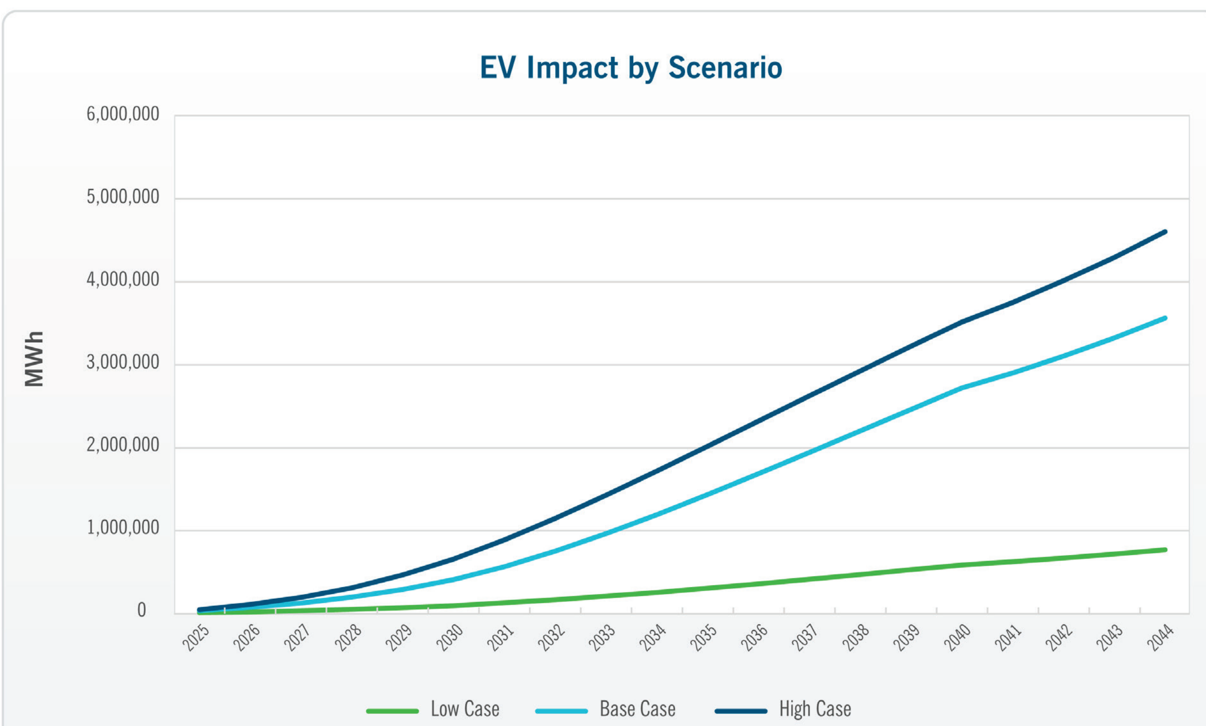


Figure D-17: Forecasted Behind-the-Meter Solar Generation Impact by Load Scenario

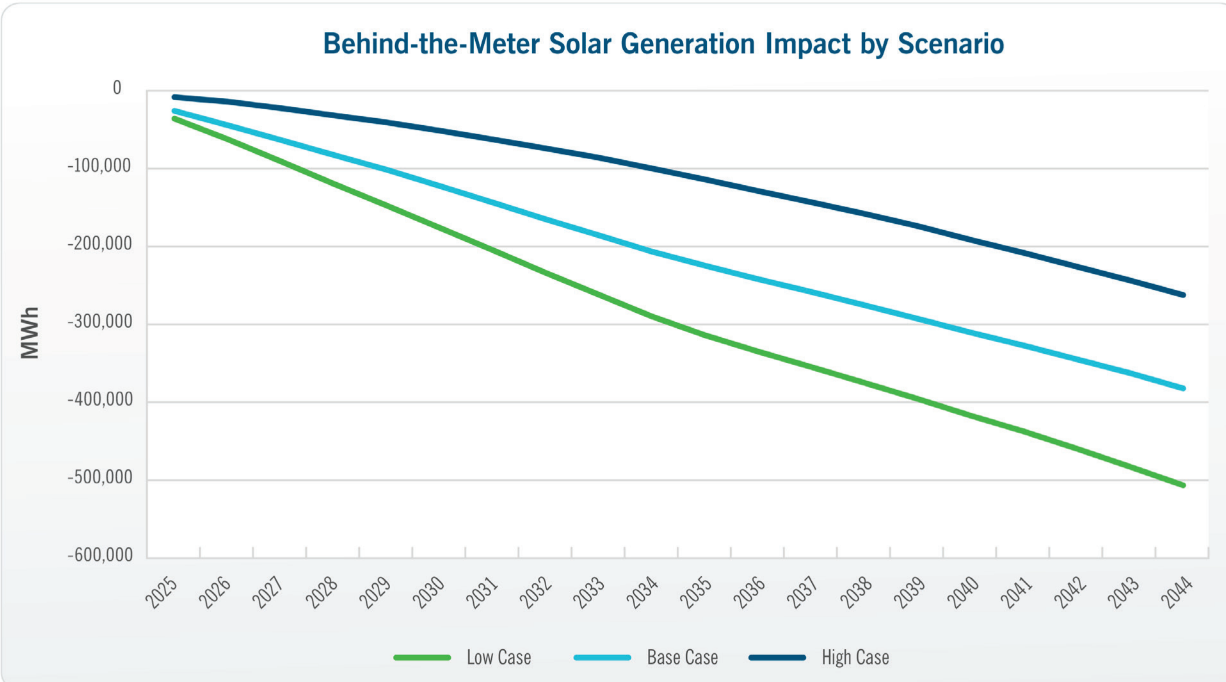


Figure D-18: Total System Generation Forecast by Load Scenario

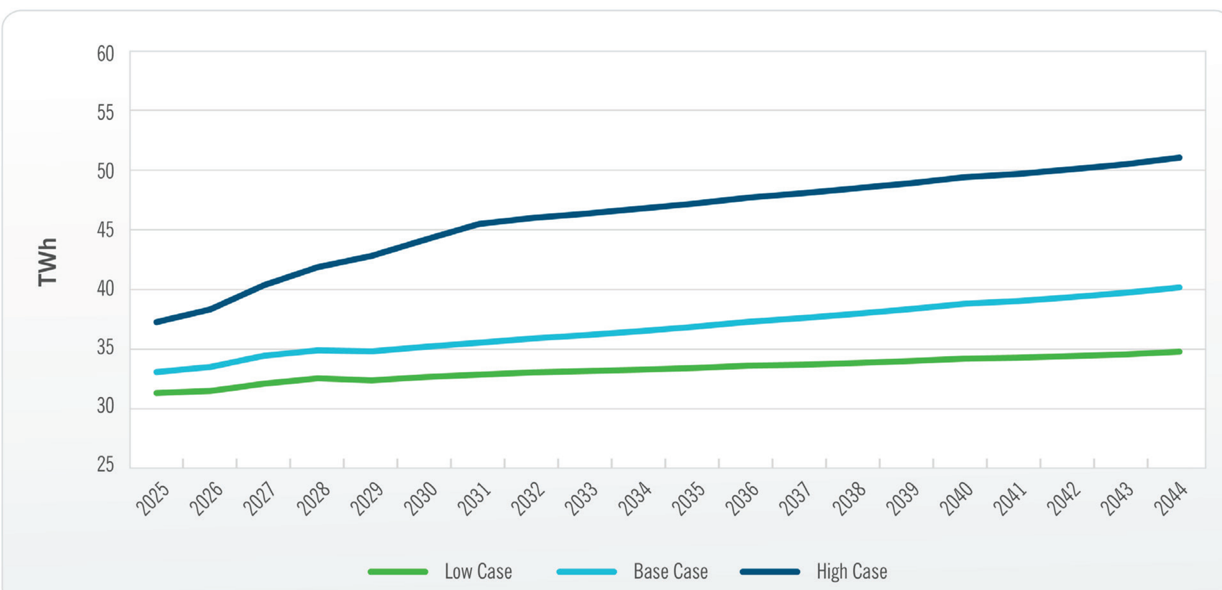
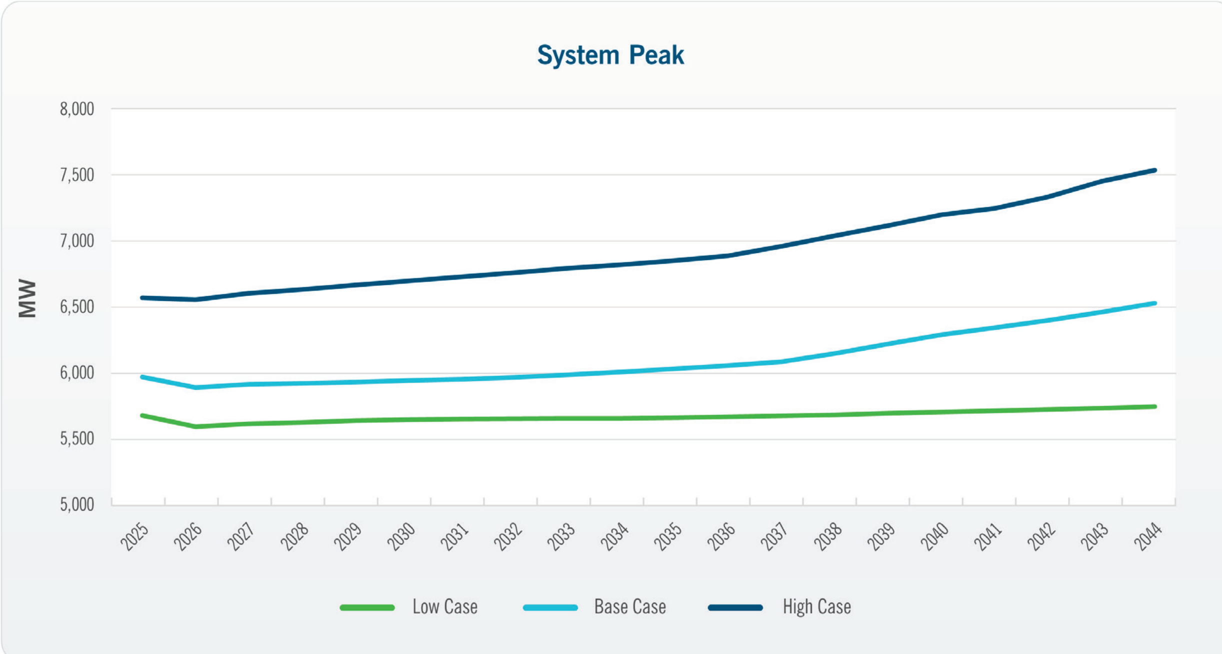


Figure D-19: Total System Peak Forecast by Scenario



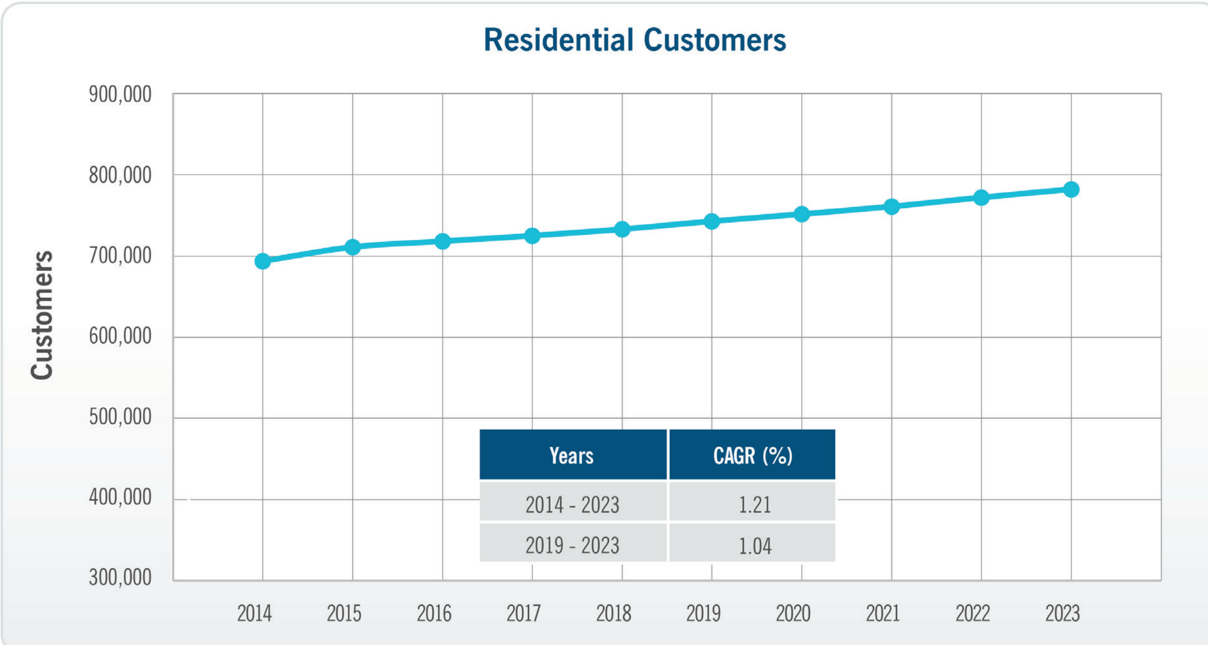
Summary of History by Major Class

Residential Customer Class

As illustrated in Figure D-20 below, residential customers had steady growth due to population growth from 2013 to 2023, which was driven by migration to the Duke Energy Indiana service area and the natural increase in population. Economic growth, the low cost of doing business, and the low cost of living were key attractors for migration into the service area. Figure D-21 below shows that while residential customers have been steadily increasing, residential sales have been relatively flat, with increased customer growth balanced by improved energy efficiency.

Illustrated in Figure D-22 below is the historical usage per customer, which has steadily declined over time due to improved electric efficiency, both market-driven and utility sponsored. There was a slight increase in usage from 2020 to 2022 driven by work at home and students remaining at home due to COVID followed by a downward adjustment to a normal level of usage in 2023 as people returned to work in the office and students returned to school.

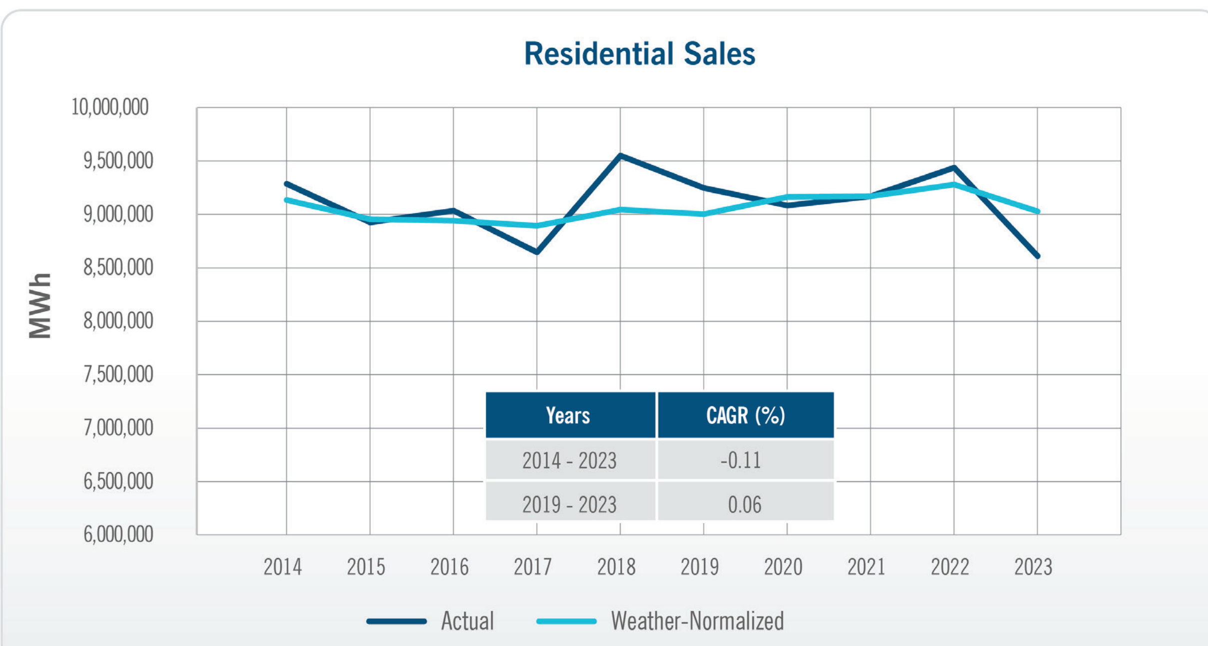
Figure D-20: Historical Residential Customers



Years	CAGR (%)
2014 - 2023	1.21
2019 - 2023	1.04

- The residential class was the primary positive driver of customer growth with a CAGR of 1.21% from 2014 to 2023.

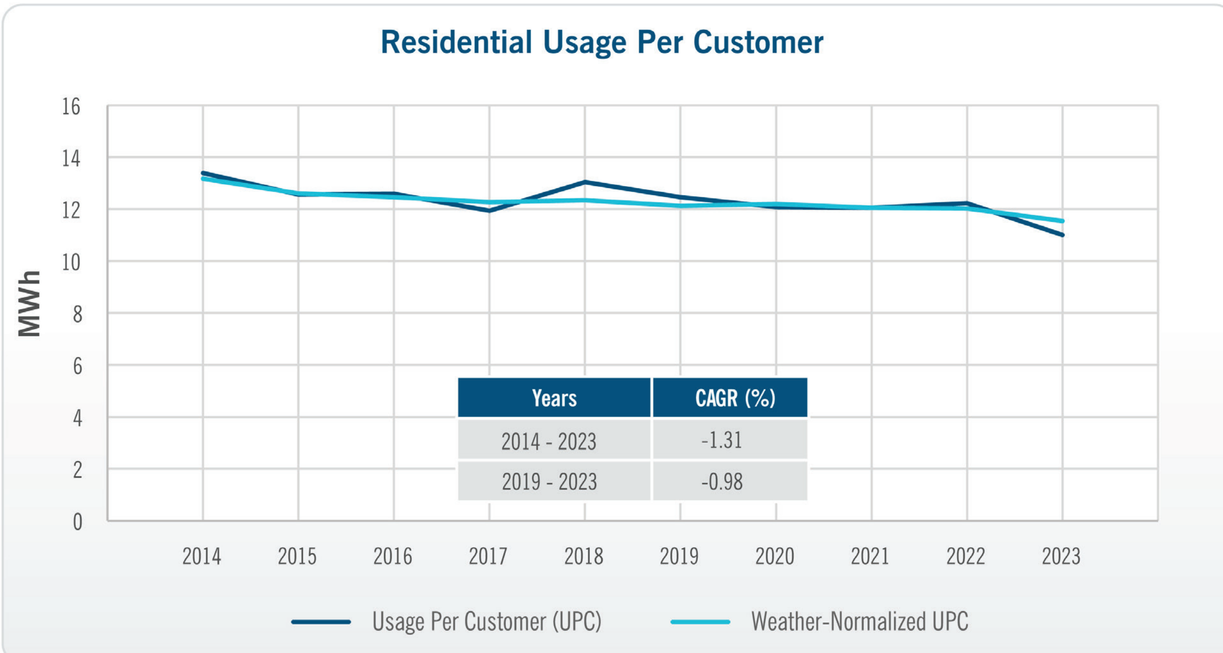
Figure D-21: Historical Residential Sales



Years	CAGR (%)
2014 - 2023	-0.11
2019 - 2023	0.06

- Residential sales have been relatively flat over the past decade, with increasing customer growth balanced by improved energy efficiency.
- More recently, the COVID-19 pandemic led to a slight increase in residential usage, which has started to correct as shown by downward shift in normalized sales from 2022 to 2023.

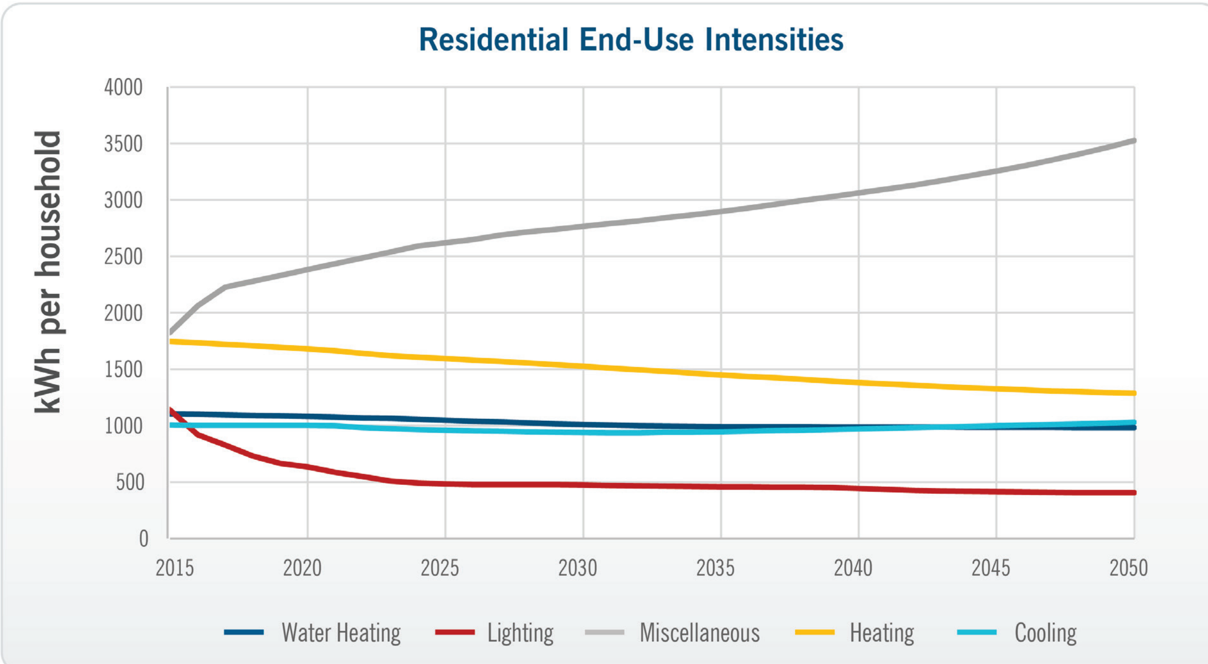
Figure D-22: Historical Residential Usage Per Customer



- Residential annual usage per customer has steadily declined, with an approximate -1.3% compound annual growth rate over the past decade.
- Declining household usage is due to higher efficiency across end uses, such as heating and cooling.
- This trend is expected to reverse in the mid-2030s due to increasing electrification trends.

Figure D-23 below shows residential end-use intensity trends. End-use intensity for the residential sector reflects the combination of changes in end-use shares and end-use efficiency to yield an average use per household over time. Efficiency increases in heating and lighting result in decreases in end-use intensity over time. Cooling and water heating end-use efficiency have remained constant and therefore the intensity remains constant. Intensity of miscellaneous end uses, which include electronics and other equipment not included in other end uses listed on the graph, continues to increase over time due to electrification in residential households driven by the expansion of electronic devices, electric cooking, and other equipment in the home. This includes electric cooking appliances and household amenities such as connected smart-home devices, chargers, gaming systems, hot tubs, and pool pumps.

Figure D-23: Residential End-Use Intensity Trends

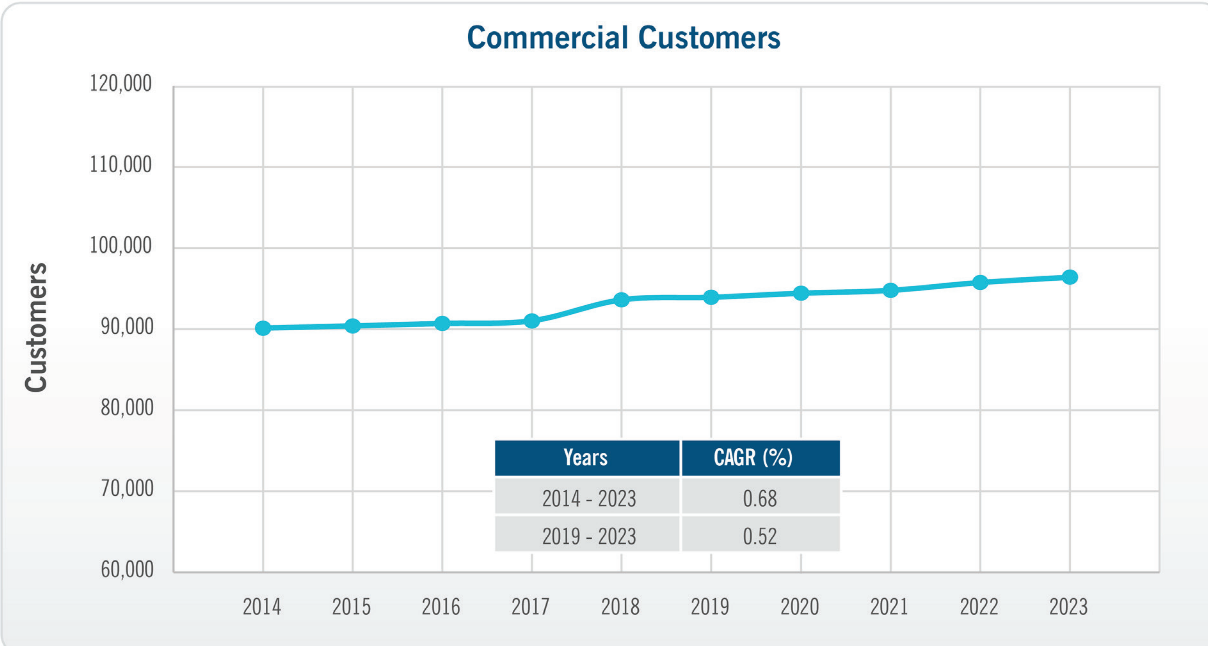


- Equipment efficiency improvements lead to lower energy usage from heating, cooling, and lighting.
- Miscellaneous electrical equipment (stovetops, air fryers, connected devices, chargers, gaming, pool pumps, etc.) drives increased usage at home over the next 30 years.

Commercial Customer Class

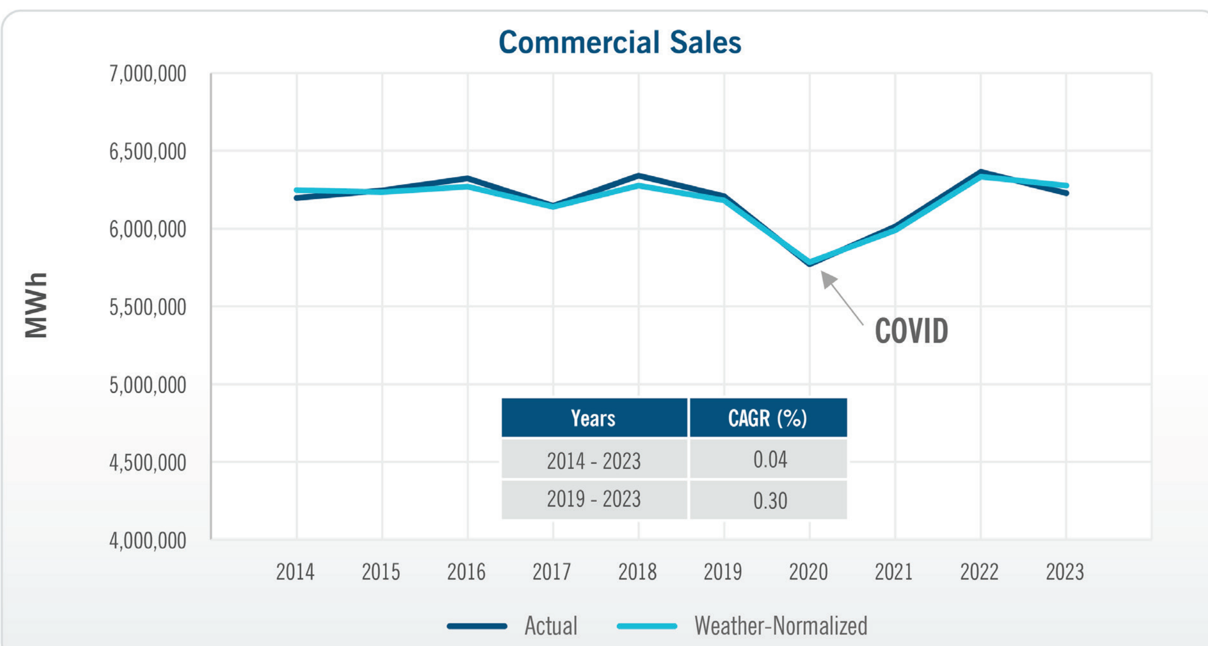
As illustrated in Figure D-24 below, commercial customer growth has been steadily increasing over time due to the support of the residential sector, which drives growth in commercial customers. As shown in Figures D-25 and D-26 below, commercial sales have remained relatively flat, and commercial usage per customer has slightly decreased over time due to energy efficiency adoption. The impact of energy efficiency improvements is expected to continue but forecasts indicate efficiency gains will be offset by electrification trends in coming years.

Figure D-24: Historical Commercial Customers



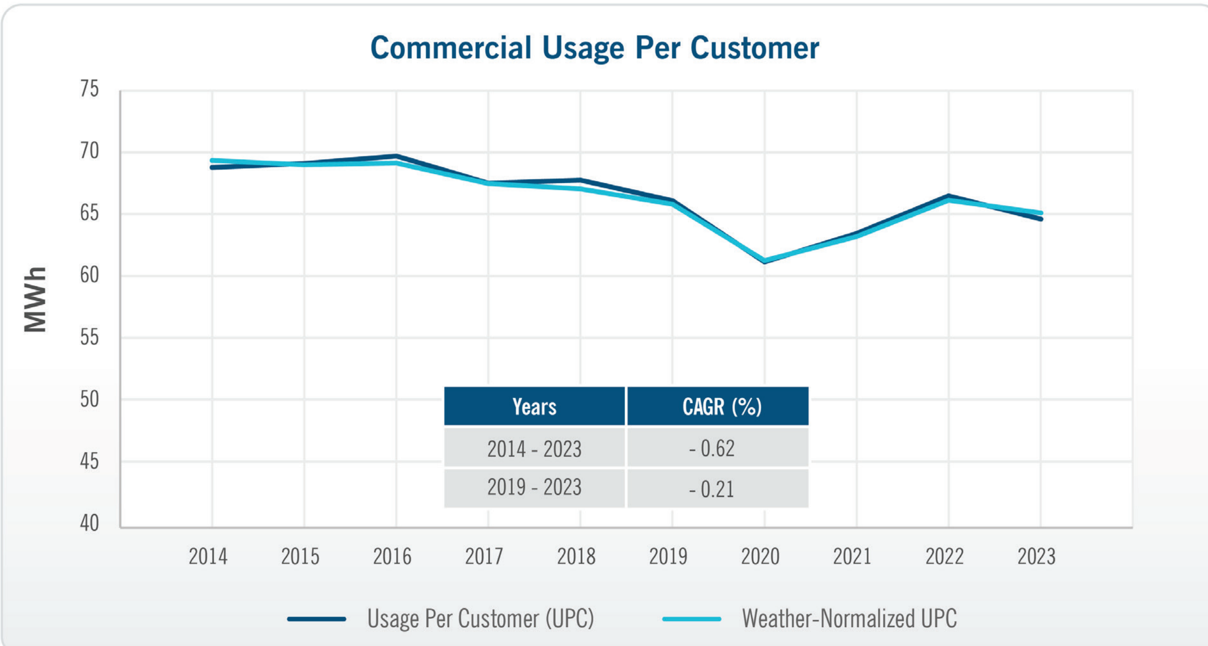
- The commercial class has seen consistent customer growth but to a lesser extent than residential customers.

Figure D-25: Historical Commercial Sales



- Commercial sales have been flat and steady over the past decade, dipping only during the pandemic. Recent energy usage suggests that commercial customers have returned to pre-pandemic usage levels.

Figure D-26: Historical Commercial Usage Per Customer

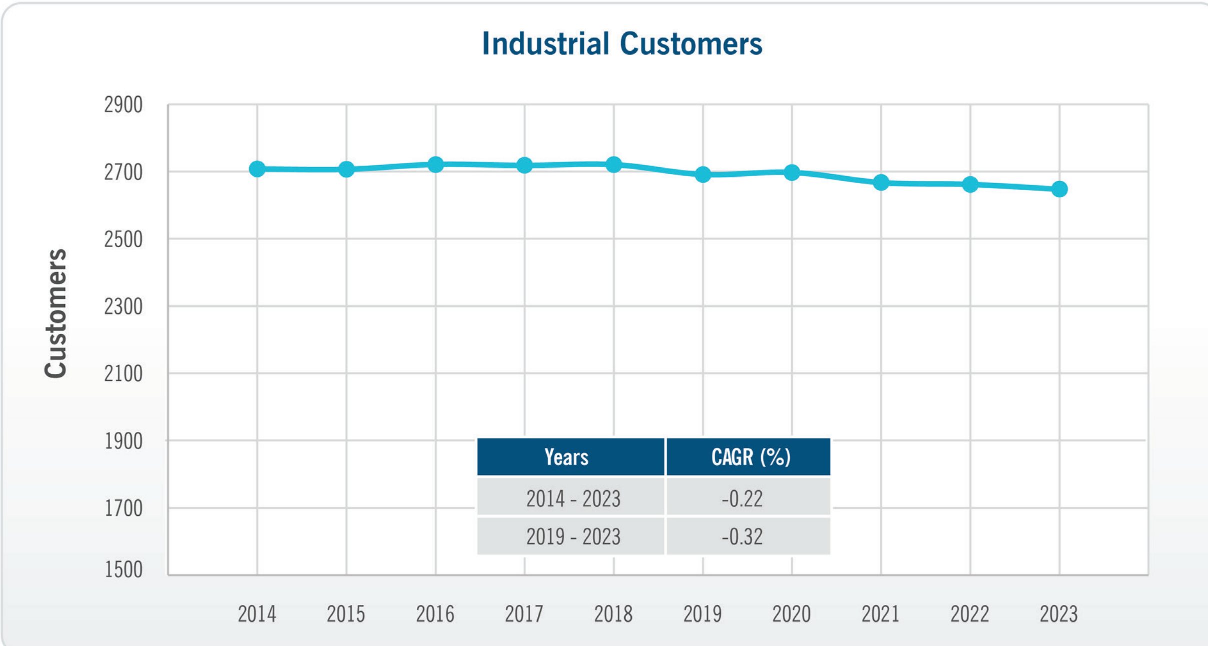


- The commercial class has seen usage per customer declining over time mainly due to energy efficiency adoption.

Industrial Customer Class

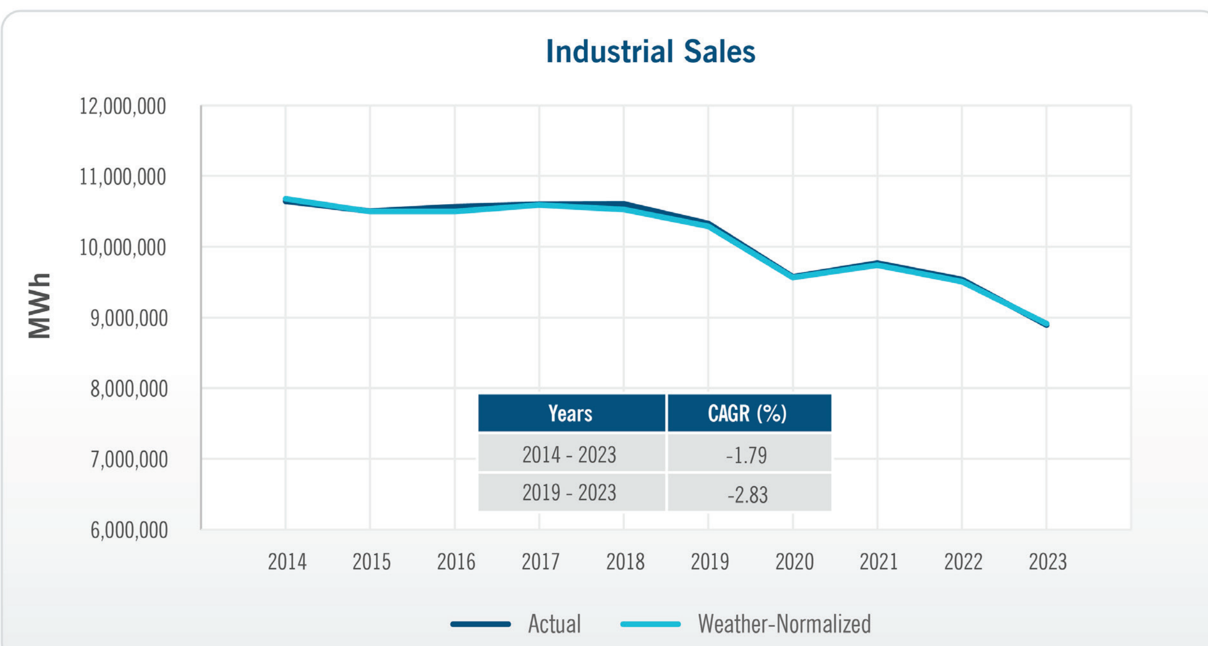
The number of industrial customers has remained flat from 2013 to 2023, as shown in Figure D-27 below. Figure D-28 below illustrates how industrial sales fell from 2018 to 2023 due to economic weakness, COVID-19 impacts in 2021 to 2022, and high industrial electric prices relative to gas prices in 2022 and 2023. Industrial weakness in 2023 is related to economic pressures including: difficulties in attracting and retaining workforce, weak domestic economy, increased raw material costs, and increased production costs.

Figure D-27: Historical Industrial Customers



- Industrial customer growth has been flat over the past decade due to inflationary pressures, higher energy prices, and supply chain disruptions.

Figure D-28: Historical Industrial Sales



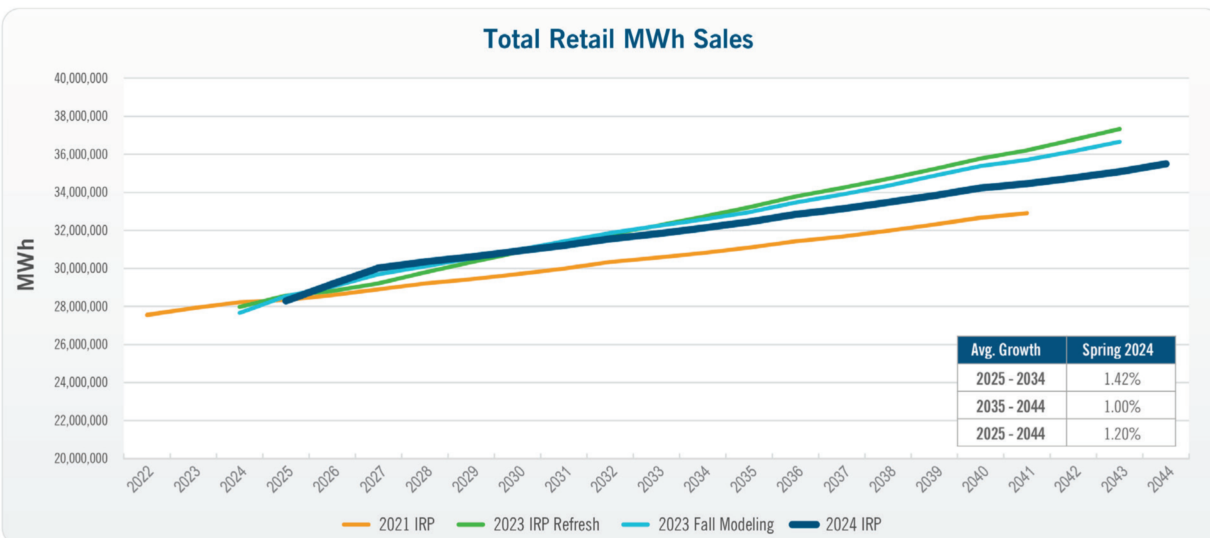
- Industrial energy usage fell during the pandemic and has struggled to reach pre-pandemic levels.

Comparison to Previous Sales Forecasts

Figure D-29 below shows the total retail sales forecast in comparison to previous load forecast versions from the past three years of modeling activities. Figures D-29 through D-32 below illustrate the comparisons by class. The versions compared include the forecasts for the 2021 IRP, 2023 IRP Refresh, 2023 Fall Modeling, and the 2024 IRP.

Overall, the 2024 IRP forecast exceeds the 2021 IRP forecast primarily due to upward pressures from economic development and EVs. The differences between the 2023 forecasts and the 2024 IRP forecast are largely due to downward pressures in the regional forecast drivers provided by Moody's.

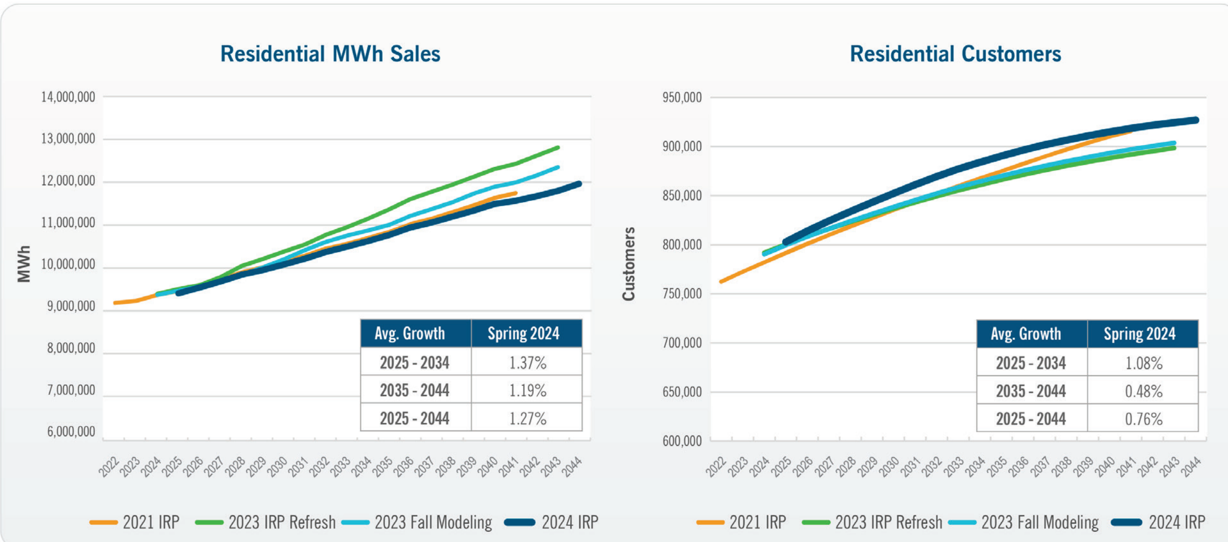
Figure D-29: Retail Sales Forecast Comparisons



Residential Forecast Comparison

The residential sales forecast shown in Figure D-30 below is driven by number of customers and usage per customer. The household forecast is higher for the 2024 IRP than in previous forecasts due to increased population growth for the Duke Energy Indiana service area. This population growth is largely driven by in-migration to the region. While the forecasted number of customers is increasing, usage per customer is decreasing. Changes in energy cost inflation, the general inflation rate, and increased electric rates have had a dampening effect on the usage per customer beyond end-use efficiencies, therefore impacting the residential sales forecast over time. The result has been a modest downward revision in the residential sales forecast for the 2024 IRP relative to the 2021 IRP.

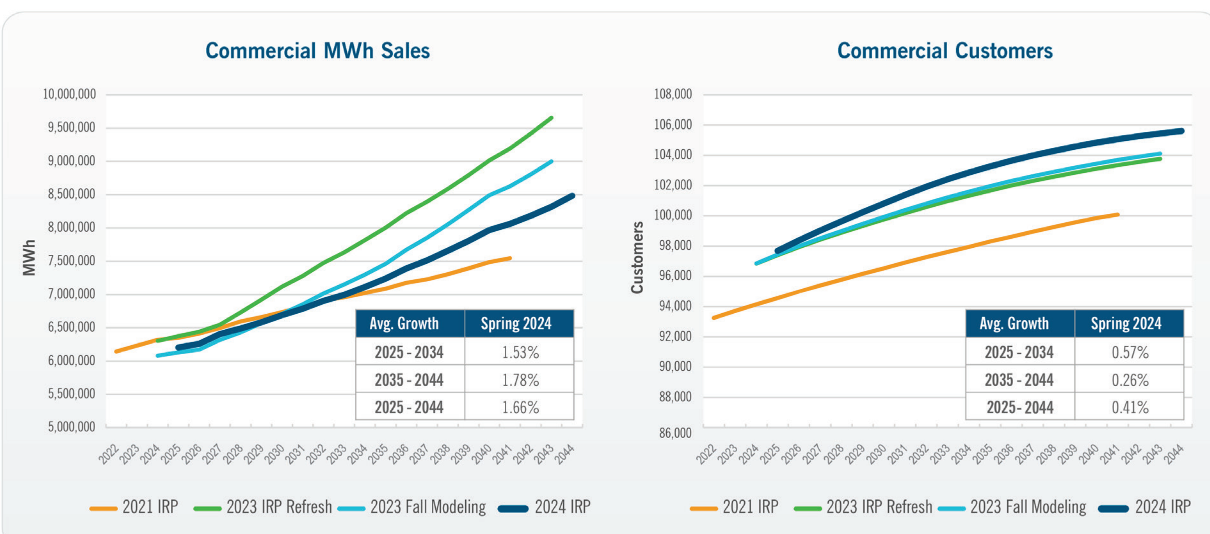
Figure D-30: Residential Customers & Sales Forecast Comparisons



Commercial Forecast Comparison

The commercial customer forecast is primarily driven by the household forecast, which has increased in the 2024 IRP forecast. Accordingly, the commercial forecast reflects similar relative adjustments across versions.

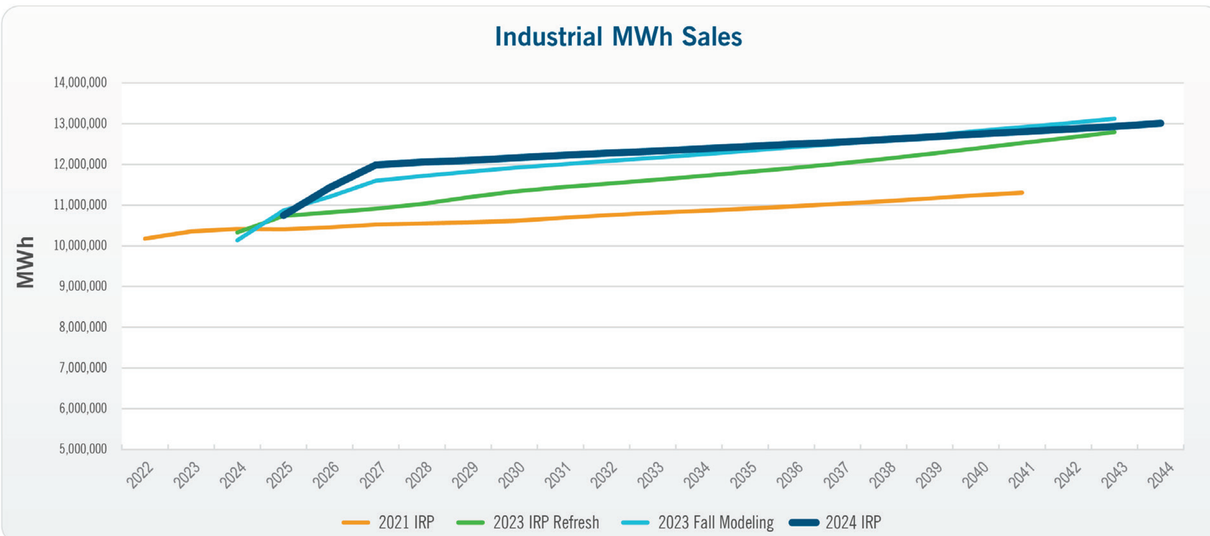
Figure D-31: Commercial Customers & Sales Forecast Comparisons



Industrial Forecast Comparison

Figure D-32 below shows the comparison of industrial sales forecasts. The growth in industrial sales is driven by increases in industry output for the current mix of industrial customers in the Duke Energy Indiana service area and the industry growth rates provided by Moody's for those specific industries in the state of Indiana. Further, economic development efforts have attracted large industrial projects over the near term, beyond what is supported by the existing composition of customers. Overall, economic development and increased industrial output are the major drivers of the increased industrial sales forecast since the 2021 IRP.

Figure D-32: Industrial Sales Forecast Comparisons



Historical Load Shapes

Figures D-33 through D-36 provide historical load shapes for Duke Energy Indiana and reflect actual system generation hourly loads under actual weather conditions in 2023. Weather adjustments are applied to the hourly load shape and the historic monthly sales history for reference and for calibration of the model to generate the forecast under normal weather conditions for the 2024 IRP. Actual weather load shapes are provided herein to reflect history without model imputation. Historical metered hourly load shapes by rate class are provided in Attachment D-1.

Figure D-33: System Generation, Hourly Load in 2023 (Annual)

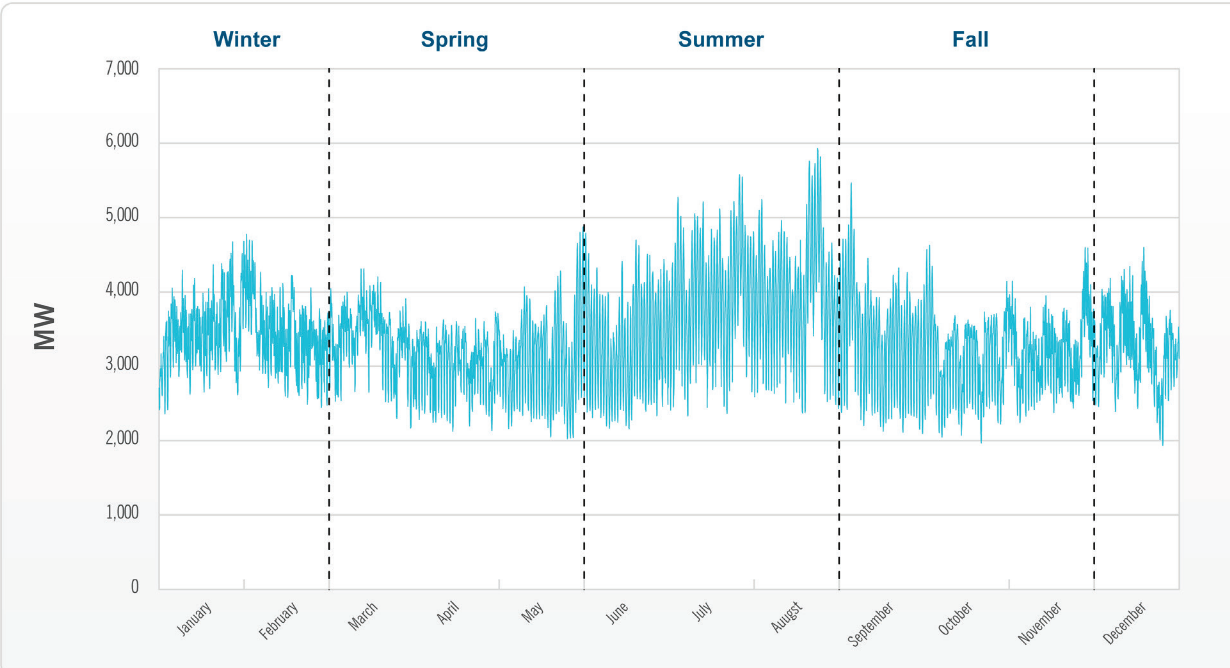


Figure D-34: System Generation, Hourly Load in January 2023 (Winter)

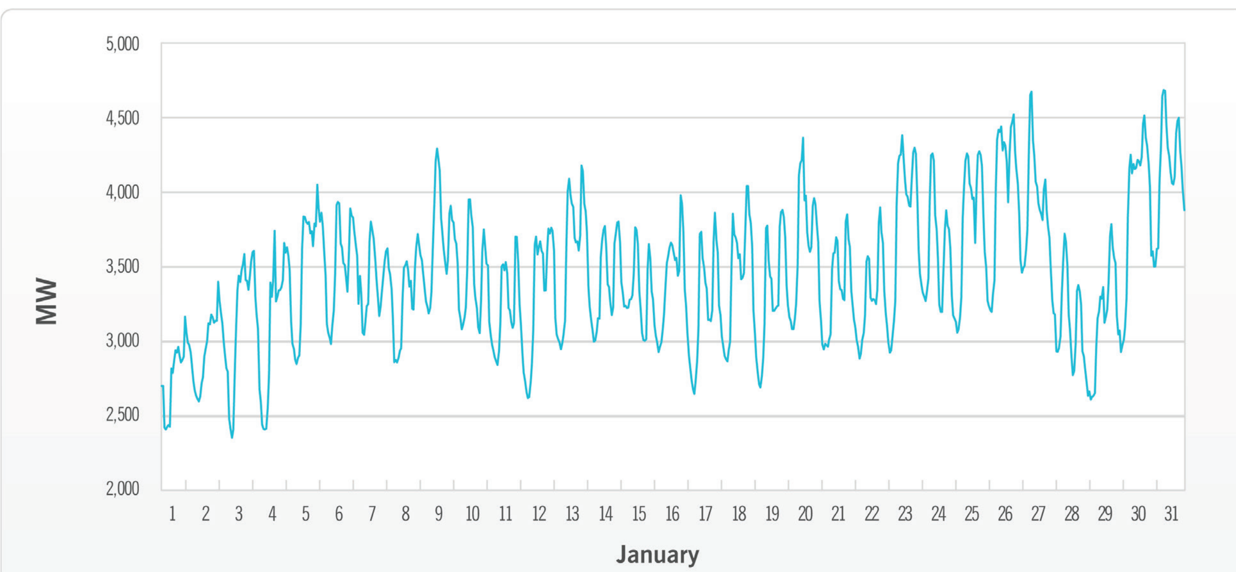


Figure D-35: System Generation, Hourly Load in August 2023 (Summer)

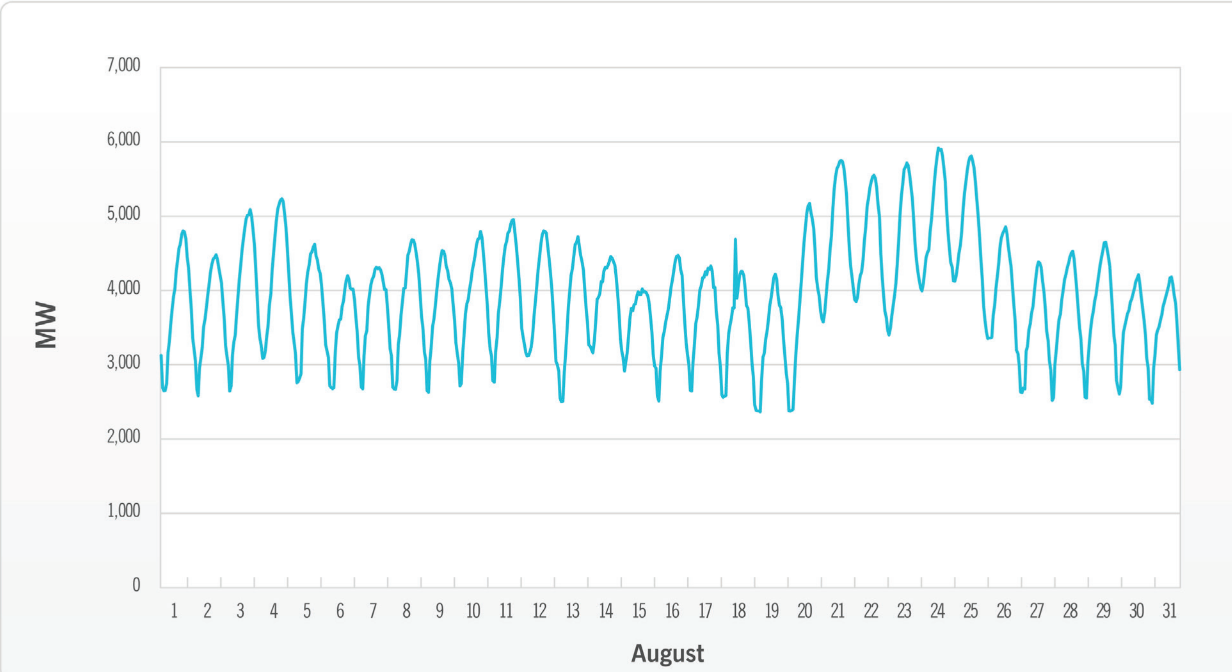
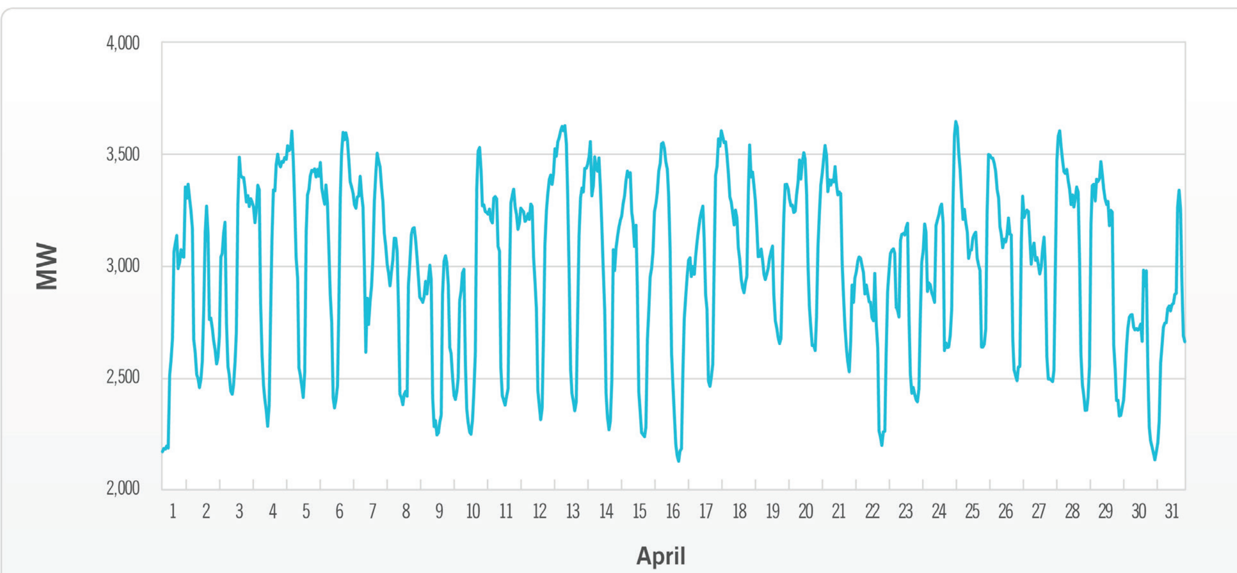


Figure D-36: System Generation, Hourly Load in April 2023 (Spring, Shoulder Month)



Figures D-37 through D-39 below reflect weekday load shapes. The hourly loads are averaged by day of week in the month specified by the chart title.

Figure D-37: Average Day of Week Hourly Load Shapes in January 2023 (Winter)

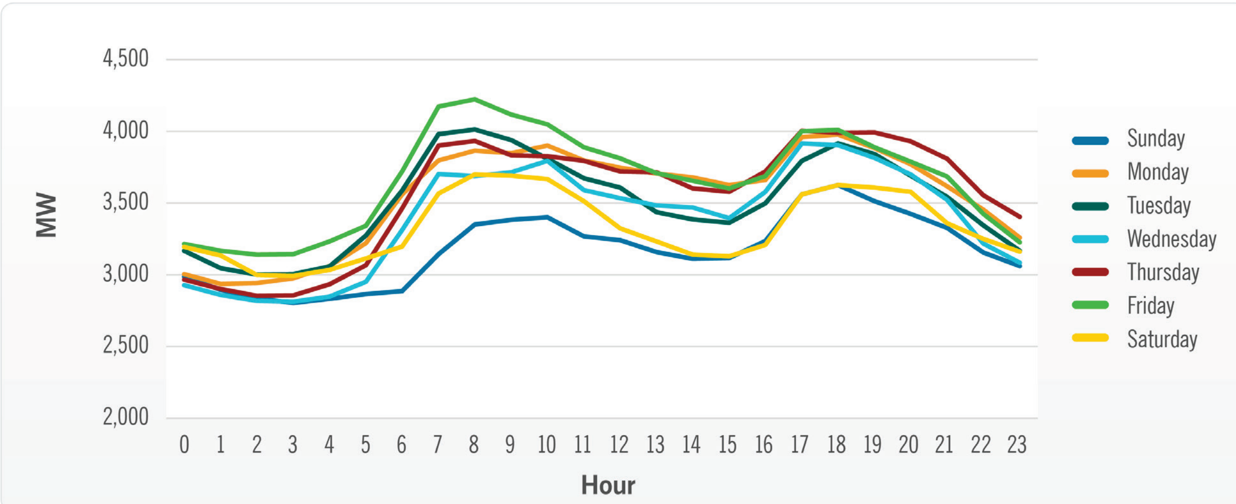


Figure D-38: Average Day of Week Hourly Load Shapes in July 2023 (Summer)

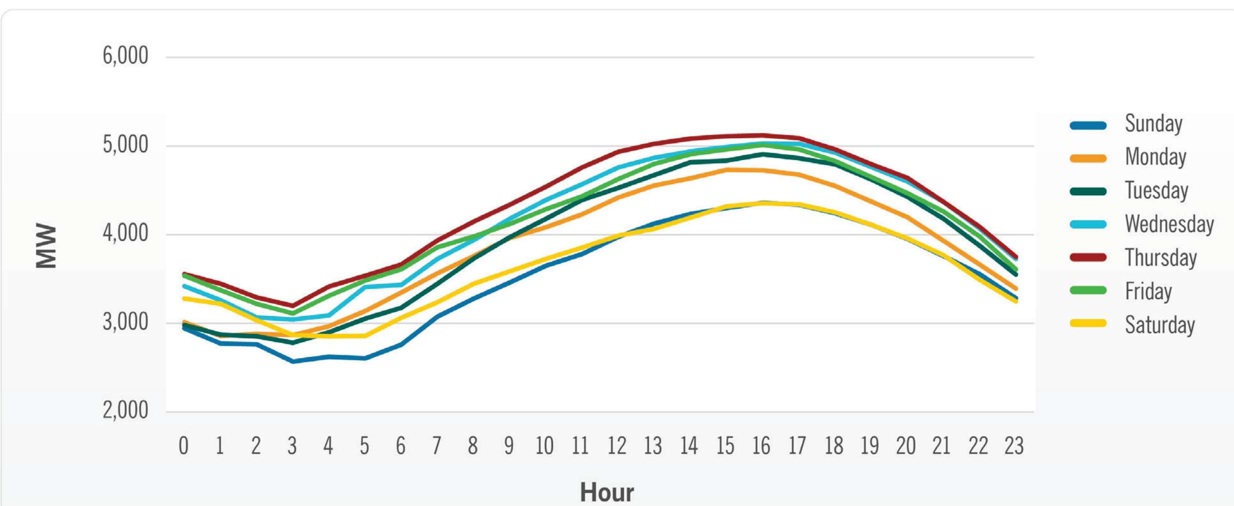
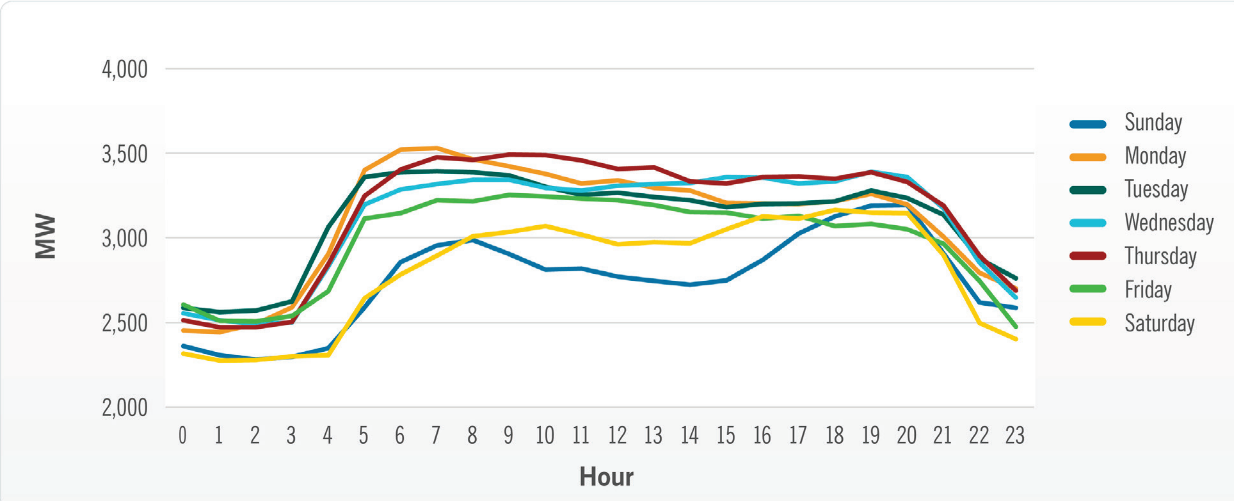


Figure D-39: Average Day of Week Hourly Load Shapes in April 2023 (Spring, Shoulder Month)



End-Use History and Forecast

The imputed cooling, heating, and other end uses for the residential and commercial sectors are used as explanatory variables in the sales models. Itron's end-use intensity data for the Midwest is calibrated to Duke Energy Indiana service area sales and fuel shares along with weather data. The SAE models for the residential and commercial sectors derive the imputed end-use history and forecast for the residential and commercial sectors shown in Tables D-20 and D-21 below.

Table D-20: Imputed End-Use History for Residential and Commercial Sales Models (MWh)

Year	Res Heat	Res Cool	Res Base	Com Heat	Com Cool	Com Base
2015	2,858,547	1,892,755	4,105,325	293,938	568,683	5,309,575
2016	2,624,584	2,189,443	4,105,325	262,028	660,495	5,309,575
2017	2,485,303	1,983,307	4,105,325	241,800	600,348	5,309,575
2018	3,142,718	2,503,445	4,131,139	304,720	763,019	5,470,106
2019	3,004,206	2,178,031	4,263,336	288,126	659,880	5,468,391
2020	2,713,742	2,059,443	4,558,917	254,345	604,830	5,078,081
2021	2,728,218	2,219,840	4,550,863	262,195	682,908	5,280,970
2022	2,975,841	2,196,561	4,298,448	286,599	685,649	5,155,920
2023	2,505,137	2,077,005	4,393,849	240,726	654,411	5,383,373
2015-2023	-353,410	184,250	288,524	-53,213	85,728	73,798
2015-2023 CAGR	-1.64%	1.17%	0.85%	-2.47%	1.77%	0.17%

Table D-21: End-Use Forecast for Residential and Commercial Sales Models (MWh)

Year	Res Heat	Res Cool	Res Base	Com Heat	Com Cool	Com Base
2025	2,964,074	2,136,392	4,279,967	280,364	679,117	5,241,235
2026	2,984,739	2,157,472	4,352,890	280,771	688,427	5,272,579
2027	3,004,503	2,176,742	4,430,201	280,299	695,924	5,389,070
2028	3,034,284	2,197,239	4,515,026	281,587	705,443	5,428,312
2029	3,035,472	2,220,569	4,572,018	281,376	718,870	5,458,012
2030	3,046,646	2,243,652	4,637,572	282,506	730,163	5,494,909
2031	3,051,605	2,265,835	4,697,929	282,574	739,432	5,512,164
2032	3,063,183	2,285,758	4,764,381	283,386	747,405	5,540,192
2033	3,046,361	2,315,775	4,800,403	281,562	755,069	5,537,740
2034	3,036,812	2,337,370	4,840,441	280,928	762,079	5,551,448
2035	3,024,862	2,359,341	4,883,274	280,085	769,340	5,563,685
2036	3,024,725	2,381,314	4,940,861	280,237	776,612	5,591,217
2037	2,995,361	2,403,023	4,968,051	277,830	783,274	5,585,116
2038	2,977,591	2,424,581	5,008,499	276,663	790,571	5,596,844
2039	2,960,542	2,446,615	5,048,732	275,527	797,665	5,607,717
2040	2,956,441	2,467,920	5,097,869	275,485	803,729	5,638,411
2041	2,924,836	2,488,086	5,114,050	272,894	810,380	5,639,644
2042	2,905,974	2,507,816	5,149,024	271,504	817,913	5,658,434
2043	2,888,657	2,527,745	5,188,254	270,154	826,526	5,681,924
2044	2,885,588	2,548,349	5,247,301	270,055	835,926	5,723,909

Wholesale Historical and Projected Load Forecast

As discussed earlier in this Appendix, the sales and demand forecast for the wholesale class is based on Duke Energy Indiana's existing wholesale contracts through 2030. Wholesale sales in 2030 are assumed to continue through the remainder of the planning period (2044). The historical and projected wholesale peak demand and sales forecast is provided in Tables D-22 and D-23 below.

Table D-22: Historical Wholesale Demand and Sales

Year	Actual Sales (MWh)	Actual Peak (MW)	Weather Normal Peak (MW)
2013	1,705,090	270	266
2014	2,558,210	420	413
2015	3,681,545	474	485
2016	4,106,469	665	626
2017	2,869,024	525	543
2018	2,887,579	423	407
2019	2,399,937	417	414
2020	2,763,300	535	541
2021	2,805,960	435	417
2022	3,256,591	445	429
2023	2,502,861	455	460

Table D-23: Forecasted Wholesale Demand and Generation

Year	Wholesale at Generation (MWh)	Contribution to Peak (MW)
2025	2,493,260	361
2026	1,954,409	254
2027	1,982,557	254
2028	2,102,379	254
2029	1,715,456	254
2030	1,786,848	254
2031	1,786,848	254
2032	1,786,848	254
2033	1,786,848	254
2034	1,786,848	254

2035	1,786,848	254
2036	1,786,848	254
2037	1,786,848	254
2038	1,786,848	254
2039	1,786,848	254
2040	1,786,848	254
2041	1,786,848	254
2042	1,786,848	254
2043	1,786,848	254
2044	1,786,848	254

Takeaways from 2022 Residential End-Use Study (Survey)

Duke Energy Indiana conducts a Residential End-Use Study ("saturation survey") every three years to gather insights on appliance and equipment inventory among residential customer throughout the service area. The last triennial customer survey was conducted in 2022; the next survey has been scheduled for 2025. The purpose of this survey is to determine the current saturation levels of various appliances among residential customers, and identify customer attitudes, perspectives and plans regarding selected energy-related issues. The results of this study are used to analyze and forecast future load levels and to make recommendations for the IRP load forecast. Some of the key survey items that provided insight or were used directly in the calibration process. Some of the key insights gleaned from the 2022 saturation survey and some of the findings used directly in the calibration process are discussed below. For industrial and commercial customer end-use saturations and efficiencies, the Company leverages EIA regional data.

Duke Energy Indiana residential customers have a higher percent ownership of home, a longer tenure in their home, and a higher percentage of single-family dwellings than the East North Central region, which indicates a likelihood for higher efficiency adoption rates. Also, the lower electric fuel share for heating would support a lower unit energy consumption ("UEC"), which would result in a negative adjustment in the calibration factor for residential electric intensity variables used in the regression model. Duke Energy Indiana's average home square footage is lower than that of than the East North Central region. Many other end uses are similar to the East North Central region. Duke Energy Indiana customers have a lower rate of pool ownership than other East North Central states. The high participation rates in the UEE programs in the Company's service area also supports a behavior of a higher adoption of market driven efficiency. The temperature settings on average are higher in the summer and lower in the winter for Duke Energy Indiana customers versus East North Central Region residential electric customers. This all supports a lower UEC in Duke Energy Indiana relative to the East North Central region. The result of these observations in the End-Use appliance study supports the 0.89 adjustment to the East North Central UEC which would result in lower UEC for each of the end uses for Duke Energy Indiana relative to the East North Central region.

Database of Electricity Consumption Patterns

Duke Energy's Load Research department maintains an internally developed database of electricity consumptions patterns disaggregated by customer class and rate class. The database is updated monthly from Duke Energy Indiana's AMI infrastructure, which supports the Company's robust load research processes. NAICS codes are stored in the Company's billing system, SAP, and are updated and maintained by designated internal business units based on customer class. The Company's Load Research department integrates this data into the database of electricity consumption on an annual basis, or as specific requirements dictate.

Demand-side management ("DSM") program participation is tracked in a participation database with the associated system impacts, which are validated and updated for Evaluation, Measurement, and Verification ("EM&V") results. DSM program participation, impacts, and costs are also reported annually in the Company's EE/DSM Rider filings. The Company's DSM programs are discussed in Appendix H.

Appendix E: Reliability & Resource Adequacy

Highlights

- The Midcontinent Independent System Operator, which operates the market region to which Duke Energy Indiana (the "Company") belongs, is projecting major potential changes in the needs of the grid driven by the retirement of traditional dispatchable generators and their replacement, in part by variable renewables such as solar and wind.

- These factors are driving rapid changes in industrywide strategies for planning for a reliable grid, including recently proposed changes to the Midcontinent Independent System Operator's capacity accreditation framework.

- In light of this new dynamic, Duke Energy Indiana has introduced a new "Enhanced Reliability Evaluation" process in this Integrated Resource Plan to help ensure the Company's future resource mix can do its part to maintain reliability of the grid and meet capacity obligations on behalf of customers.

Utilities and system operators across the country must plan and operate their generating fleets and transmission and distribution systems to provide reliable power system operations to their customers 24 hours per day, seven days per week, 52 weeks per year in accordance with federally mandated North American Electric Reliability Corporation ("NERC") Reliability standards. Duke Energy Indiana operates within the Midcontinent Independent System Operator ("MISO") market region, and, as an independent system operator spanning a wide physical and political geography, MISO shares the responsibility for ensuring resource adequacy with individual utilities and utility regulators throughout its footprint. As discussed later, the Company is responsible for bringing adequate generating resources to the table in MISO to support the reliability obligation it holds on behalf of its customers.

Within the resource planning context, resource adequacy is the concept and process by which grid planners ensure that future generating portfolios will be adequate to serve projected customer demands. To meet resource adequacy needs, Duke Energy Indiana and other utilities have long relied on conventional technologies, such as coal, natural gas, and hydropower to serve fluctuating customer demand for electricity. However, as discussed in Chapter 1 (Planning for the Future Energy Landscape), economic, technological, and regulatory drivers are changing the demand for electricity, as well as the mix of supply-side and grid edge resources expected to serve those demands. While these drivers are affecting the utility industry as a whole, they are projected to have a profound impact on MISO itself — and by extension, the economic and operating environment in which the Company plans to meet future customer demand.

To provide context for how reliability considerations have shaped the portfolios presented in the Duke Energy Indiana's 2024 Integrated Resource Plan ("IRP"), this Appendix describes the new realities posed by the changing energy landscape, the changing needs for the modeling and measurement of resource adequacy across the United States and in MISO, and introduces the Company's "Enhanced Reliability Evaluation" modeling, which further assesses the ability of future resource portfolios to serve customer demands under a variety of real-world grid conditions.

Effect of the Changing Energy Landscape on Reliability

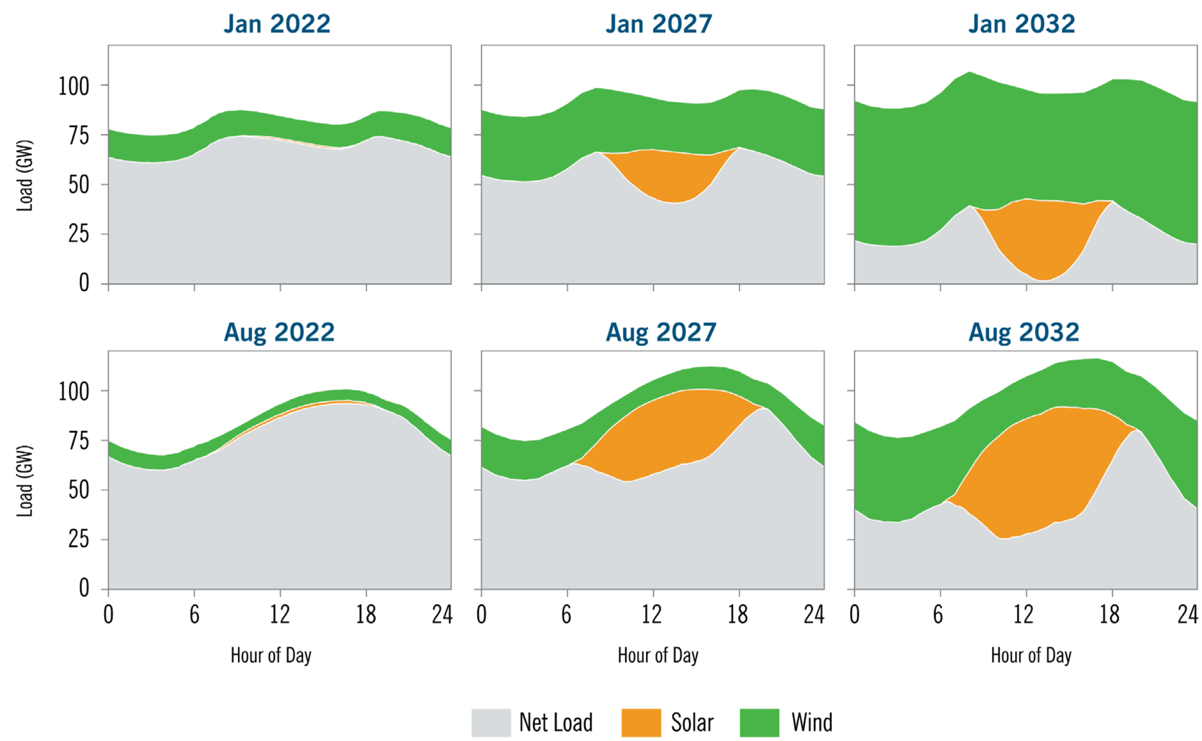
MISO has undergone, and is anticipated to continue undergoing, a rapid transition in its resource mix, from a system where energy demands were primarily served by coal, to a more diversified portfolio today that blends coal, natural gas, nuclear, and renewables, to long-term scenarios which could see a shift to much greater reliance on renewables and energy storage. New renewable resources will provide low-cost energy and enhance fuel diversity, mitigate fuel cost variability, and hedge environmental regulatory risks, but their variable, weather-dependent output will place new operating demands on the grid and ultimately change the value proposition of the essential dispatchable resources that meet customer demands when renewable energy is not available. This changing nature of electricity supply also introduces new complexities into the modeling and determination of resource adequacy to ensure that future capacity resources can adequately meet the contours of customer demands given uncertainties in the timing and magnitude of variable renewable generation.

The Changing Shape of Net Load

Traditionally, conventional resource planning has sought to ensure that future resource portfolios are adequate to meet the operational challenges presented by the peaks and valleys of customer electricity demand. However, with the evolution of the projected resource mix in MISO, available energy from these resources will vary with time and weather. Remaining electricity demand, after accounting for that variation, must be served in real time by dispatchable sources to maintain system reliability. As the capacity of variable renewables increases, the electricity demand net of renewable energy contributions, commonly referred to as "net load," is expected to undergo a structural change in shape, with shifts to the timing and magnitude of peaks and valleys in net load. This will alter the demands on dispatchable resources relative to the current system, where the timing and magnitude of customer demands is the primary driver of operations.

To illustrate this potential change in net load and system operational needs, Figure E-1 below shows a MISO projection[1] of potential future loads, renewable contributions, and net load illustrating the changing demands on dispatchable resources in the market. This figure captures the average load and renewables profiles for the months of January and August.

Figure E-1: Historical and Projected MISO Net Load Shapes



In both the summer and winter examples, wind reduces overall net load throughout the day (with more output in the evening) and additional high solar output during the middle of the day creates a deep valley in the net load profile at that time. This valley creates challenges for system operators as high renewables output can force the remaining resources on the system (resources that are necessary for meeting load during periods without wind or sunshine) down to their minimum safe operating level. On the lowest-load days, renewable energy may need to be curtailed in order to maintain system reliability if excess generation cannot be absorbed by energy storage or exported to other regions. Because renewable energy output is weather- and time-dependent, production from these resources tends to be correlated across large areas. For this reason, as renewable energy makes up a greater portion of the MISO energy mix, neighboring regions will become more likely to experience energy surpluses

[1] Figure E-1 recreates Figure 13 from MISO's December 2023 Attributes Roadmap Report using the underlying 5-minute load and renewables output data as provided by MISO. This report is available at https://cdn.misoenergy.org/2023+Attributes+Roadmap631174.pdf.

and deficits at the same times. This will make imports and exports less effective tools for managing net load variability in the future.

These changing load dynamics have the potential to increase the relative value of flexible resources that can "cycle" through midday solar peaks and/or shift energy from times of low net load (but high renewable output) to periods of higher need. It will be necessary to rely on flexible resources with dispatchable capabilities such as natural gas combustion turbine and combined cycle generators that can cycle across net load valleys to provide on-demand energy when renewable energy output cannot satisfy load on its own. Additionally, new advanced nuclear configurations are anticipated to be more flexible than traditional nuclear generators and provide some capability to ramp down during periods of high renewables output. Energy storage will play an important role in shifting energy from high to low net load periods.

Increasing Operational Uncertainty

In addition to the changing patterns of net load described above, the predictability or certainty of net load forecasts is likely to decline as weather-dependent renewables become a larger share of system resources. Because of unavoidable uncertainty in day-ahead and real-time weather forecasting, future forecast errors are predicted to grow. In its analysis of potential high renewable energy futures, MISO found that by 2032, in particularly severe cases (95th percentile), day-ahead solar forecast errors could exceed 17,000 megawatts ("MW") and day-ahead wind forecast errors could exceed 11,000 MW compared to 2022 actual 95th percentile errors of approximately 200 and 3,000 MW, respectively.[2] Intraday errors and sub-hourly volatility are expected to similarly increase.

Growing levels of power system uncertainty will require corresponding changes to system ancillary service reserves to manage forecast uncertainties and regulating reserves to manage real-time fluctuations in customer loads and renewable output. These capabilities must be provided by system resources with dispatchable characteristics.

Energy Adequacy

Historically, resource adequacy has generally been synonymous with having sufficient *capacity* resources available to reliably serve electric demand, with consideration given to items including, but not limited to, unplanned outages of generating equipment, uncertainties in load and renewable forecasts, fuel availability, and significant deviations from expected output from weather-dependent renewables caused by extreme weather events.

While capacity adequacy remains a vital consideration for resource planning, projected higher levels of renewable generation and reliance on energy storage necessitate further review and analysis of *energy* adequacy. The changing nature of reliability risk means a region may have adequate nameplate capacity to meet load, but the uncertain timing of energy availability from those resources introduces new energy adequacy risks. Variability in weather patterns leading up to peak events may

[2] MISO 2023 Attributes Roadmap Technical Appendix, pp.35-36, June 2024, available at https://cdn.misoenergy.org/2023+Attributes+Technical+Appendix631176.pdf.

not allow renewables to generate energy to meet demand in all hours. Similarly, short-term forecast uncertainty may create challenges for optimal charging and discharging of energy storage resources.

In systems becoming more reliant upon variable renewables for energy to both directly meet load and to charge energy storage, new risks are emerging of the potential for long-duration events with unfavorable weather conditions (e.g., low wind speeds or cloudy weather). Such events could threaten reliability if adequate backup capacity is not available. For example, MISO has identified historical periods of sustained low wind output that have corresponded to some winter peaking events, including Winter Storm Uri in 2021.[3] Energy adequacy risks can also extend to fuel supply-related risks for natural gas generators, should weather disrupt upstream supply or high demand cause localized pipeline pressure issues.

While energy adequacy concerns will be a reality in systems with major contributions from resources dependent upon "just-in-time" fuel (including wind and solar "fuels"), this does not mean that such resource mixes are inherently unreliable. All resources bring unique combinations of capabilities to reliably and cost-effectively meet customer demands. When these resources are deployed in a balanced portfolio, they are, in aggregate, capable of addressing capacity and energy adequacy risks posed by the range of potential grid operating conditions. Over-reliance on any one type of resource can leave the system at elevated risk of common failure modes, and an "all-of-the-above" approach to system planning that values resource diversity helps mitigate such risk. A changing approach to resource adequacy modeling is necessary to capture the potential real-world uncertainties that drive power system risk to ensure that reliability can be maintained as the system configuration evolves.

Evolution of Reliability Modeling & Resource Adequacy Needs

Within the broader electric power sector, resource adequacy can generally be defined as an assessment of whether a power system has an appropriate set of resources to maintain continuous service to meet demand, with a desired level of certainty.[4] Historically, resource adequacy has entailed planning of system capacity resources to meet a future load forecast plus a reserve margin that accounts for load uncertainty and generator availability. In systems that were largely dominated by thermal generation, this was typically done without the need for detailed operational modeling that simulated the commitment and dispatch of units, and instead relied on statistical measures of unit availability and load to determine the necessary reserve margin for a system.

However, the beginning of the energy transition to greater reliance on natural gas, renewable, and storage resources has shifted the industry focus in resource adequacy toward needs related to energy adequacy and correlated risks to reliability. These concerns have been highlighted by recent extreme weather events — including firm load shed in the Electric Reliability Council of Texas during Winter

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[3] MISO Reliability Imperative, p. 11, February 2024, available at https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[4] Electric Power Research Institute: Resource Adequacy for a Decarbonized Future, A Summary of Existing and Proposed Resource Adequacy Metrics, April 25, 2022, available at https://www.epri.com/research/products/000000003002023230.

Storm Uri in 2021[5] and load shed and energy emergency declarations in the southeast and Pennsylvania-New Jersey-Maryland Interconnection ("PJM") during Winter Storm Elliott in 2022.[6]

Within regions in the U.S. (including MISO), resource adequacy in planning relies on two interrelated concepts:

1. The **Planning Reserve Margin ("PRM")** specifies the amount of accredited capacity a utility must procure to ensure it has adequate resources to meet its future load obligations. The PRM is typically specified as a percentage of a future load forecast, and in MISO varies by season. For example, under MISO's current capacity accreditation framework, in the winter season Duke Energy Indiana must procure 16.8% more accredited capacity than its forecasted winter peak load to meet MISO market requirements. Appendix C (Quantitative Analysis) documents the PRMs used in the 2024 IRP modeling in more detail.

2. **Capacity Accreditation** is the process by which MISO determines how much capacity a given resource can be relied upon to provide in meeting the PRM. Resources are typically accredited at a lower capacity than their full "nameplate" generating potential to account for the probability that they will not provide full capability when called upon due to adverse fuel supply or weather conditions, or due to unanticipated outages.

In capacity accreditation, resources can be accredited based on some combination of historical performance-based assessment (i.e., how well units have performed during reliability events) or based on forward-looking (modeled) contribution to meeting future peak demands.[7] Perhaps the most well-known model-based accreditation approach is the use of Effective Load Carrying Capability ("ELCC"), a measurement of how well the availability of a generation resource (or class of resources) aligns to additional system demand (load), typically expressed as a percentage of installed capacity. ELCC is now commonly used to determine the capacity contributions of renewable resources and storage. Importantly, the ELCC of variable renewable resources tends to decline with higher penetrations of a given resource type. This is most notably the case for solar, as increasing levels of daytime generation will shift the highest periods of net load demand towards the evening hours, where incremental solar capacity additions will not contribute as directly to resource adequacy. Conversely, certain combinations of resources — particularly renewables and storage — can have synergistic effects where higher levels of one resource can raise the capacity value of the other.

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[5] FERC and NERC, The February 2021 Cold Weather Outages in Texas and the South-Central United States, November 2021, available at https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[6] FERC and NERC, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, October 2023, available at https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

[7] A variety of approaches are discussed in Energy Systems Integration Group. Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation, February 2023, available at https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf.

The general direction of resource adequacy modeling improvement is towards increased realism in modeling, e.g., by running studies, which incorporate key operational details to account for weather-related risks to thermal generators, the timing of energy output by weather-dependent renewables, and the utilization of energy storage during potentially energy-constrained periods of time.

Industry consortia are actively working to advance the practice of resource adequacy modeling. The Energy Systems Integration Group ("ESIG") has recently released reports on accreditation principles[8] and reliability metrics, and the Electric Power Research Institute ("EPRI") maintains an ongoing industry program devoted to resource adequacy modeling.[9]

In actual market practice, new accreditation approaches are being pursued to ensure that resource adequacy properly accounts for the changing nature of system demands associated with the changing energy landscape. In October 2023, PJM filed proposed changes to its capacity accreditation methodology to address projected future reliability concerns related to the projected change in resource mix and the reliability issues experienced as part of Winter Storm Elliot in December 2022.[10] In its accreditation reform proposal, PJM transitions accreditation to a marginal ELCC methodology for all resources to better account for correlated risks to power system reliability. Federal Energy Regulatory Commission ("FERC") approved PJM's revised accreditation modeling approach in January 2024.[11] Additionally, as will be discussed in more detail below, MISO itself is the most recent market region to pursue a new capacity accreditation strategy, submitting its proposed Direct Loss-of-Load ("DLOL") methodology to FERC in March 2024.

The Midcontinent Independent System Operator's Changing Approach to Resource Adequacy

Just as the broader industry has grappled with the impact of the energy transition on resource adequacy, MISO has also begun to implement and plan changes to the way in which it models, values, and procures resources to ensure reliability across all planning timescales.

In recent years, MISO has both been subjected to tighter system conditions and begun forecasting potential future reliability concerns. The region has been experiencing more frequent "near-miss" events in which, although all customer load was able to be served, the market was forced to call upon all available resources to do so.[12] These "Maximum Generation" events indicate periods when MISO projected it would need to utilize emergency generating resources or demand response to maintain system reliability. Additionally, MISO entered the 2022/2023 Planning Year with a noted shortage of

[8] Id.

[9] EPRI, Projects and Reports under P173C Flexibility and Resource Adequacy program, available at https://www.epri.com/research/programs/067417.

[10] PJM, FERC Docket ER24-99, October 13, 2023, available at https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20231013-5157.

[11] FERC, Docket ER24-99, January 30, 2024, available at https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20240130-3113.

[12] MISO Inc., Prepared Direct Testimony of Todd Ramey, March 28, 2024, available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=250CEEE7-8374-C7E2-A0B3-8E86C0400000.

capacity resources, resulting in the potential for elevated reliability risk and rising capacity market prices.[13] In response to these instances and the broader challenges facing the electric power industry, MISO has joined the other market regions in the Eastern Interconnection in developing new resource adequacy modeling strategies for ensuring adequate reliability as the generation mix continues to change.

The first major change that MISO has made is the move from an annual to seasonal capacity accreditation framework beginning on June 1, 2023. This Seasonal Accredited Capacity ("SAC") construct values resources differently during the winter, spring, summer, and fall seasons. Individual generating resources can contribute to market reliability differently based on changes in the timing of generator availability relative to system needs. For example, the output from solar resources generally aligns with summer load peaks in late afternoon but contributes less during winter demand peaks in the morning and late evening. The timing and duration of maintenance activities also varies seasonally, with generators often choosing spring and fall periods for long outages due to lower customer demand, changing the capacity available to meet the PRM. In recent years, MISO has noted that many of its Maximum Generation declarations have occurred outside of the traditional summer peak reliability period.[14]

Beyond the transition to a seasonal resource adequacy framework, on March 28, 2024, MISO submitted a new probabilistic capacity accreditation framework to FERC for approval and implementation beginning on June 1, 2028 (i.e., the 2028/2029 planning year). The DLOL modeling framework would be used in conjunction with historical performance measures to bring all resource classes under a common accreditation framework that evaluates the marginal contribution of different resource types to system reliability. Although this new capacity accreditation framework is not yet formally approved (as of this writing) and MISO has noted that many underlying modeling assumptions are still under development, the proposed DLOL framework is likely representative of the future capacity accreditation paradigm and is therefore the most appropriate approach for long-term resource planning.

Capacity Accreditation Assumptions in the Integrated Resource Plan

As capacity accreditation is a fundamental driver of a grid resource's value in MISO and the extent to which it can contribute to Duke Energy Indiana's required planning reserve requirements, the Company must make important assumptions about resource accreditation as part of its IRP modeling. The development of the precise values used in the 2024 IRP assumptions is discussed in more detail in Appendix C, but a few of the concepts discussed in this Appendix help to understand the accreditation values, specifically:

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[13] Specifically, MISO's Central (in which Duke Energy Indiana is situated) and Northern zones experienced a combined shortfall of 1.3 GW of capacity in the 2022/2023 Planning Resource Auction (PRA). MISO Inc., 2022/2023 PRA Results, April 14, 2022, available at https://cdn.misoenergy.org/2022+PRA+Results624053.pdf.

[14] MISO Inc., Prepared Direct Testimony of Todd Ramey, March 28, 2024, available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=250CEEE7-8374-C7E2-A0B3-8E86C0400000.

1. Resources are accredited using MISO SAC values in effect from 2025–2027.

2. Resources are accredited utilizing MISO-generated DLOL class-based values beginning in 2028, consistent with MISO's proposed implementation date for the new methodology.

3. Renewable resources and storage experience declining ELCC values at higher levels of deployment throughout the MISO footprint, capturing the marginal value of these resources to reliability as more are added to the system. These changing ELCC values are based on those found in recent MISO studies of varying renewables levels in future scenarios.

Modeling Reliability & Resource Adequacy

While MISO maintains day-to-day operational reliability within its footprint, Duke Energy Indiana must ensure that it plans for a future resource portfolio that cost-effectively supplies capacity and energy when needed to meet its obligation to its customers and the broader market. To do so, this plan has included best-available information on the potential capacity value/accreditation of future resources as described Appendix C. However, as discussed previously, the specific modeling mechanisms by which the MISO market will value future capacity remains in flux with the broader DLOL approach awaiting approval by FERC and many of the underlying modeling details yet-to-be finalized by MISO itself.

While MISO's capacity accreditation construct will undergo significant change in the coming years, Duke Energy Indiana has introduced a new modeling component within the 2024 IRP to probabilistically evaluate the alignment of future portfolios with customer demand, the Enhanced Reliability Evaluation.

Enhanced Reliability Evaluation Approach

As part of the resource planning process, Duke Energy Indiana has run a probabilistic set of simulations to evaluate the relative ability of the modeled portfolios to meet customer demand under a variety of potential real-world conditions using the Strategic Energy Risk Valuation Model ("SERVM"), the same model used in MISO's own probabilistic planning analyses. Some key features of this modeling effort include:

- **Weather Uncertainty**: Simulating 44 years (1980-2023) of historical weather patterns to quantify portfolio performance uncertainties related to weather-dependent customer loads and variable renewable output.

- **Unit Availability Uncertainty**: Existing and new generating assets are all subject to uncertainties with respect to their availability to serve customers. This approach includes the simulation of 50 scenarios of unexpected unit outages or reduced generating capability in addition to routine, planned maintenance activities that render generating capacity unavailable for a period of time.

- **Economic Load Forecast Error**: Given inherent uncertainties in future load forecasts, the SERVM-based reliability analysis uses probabilistic estimates of higher and lower load growth due to economic activity to further inform the ability of a portfolio to meet uncertain demands. The Company's analysis uses the five economic load forecast uncertainty scenarios currently in use by MISO in its probabilistic modeling activities.[15]

- **Hourly Dispatch**: The SERVM model uses 8,760-hour production cost simulation under operational constraints to address energy adequacy. This hourly approximation of system operations allows the Company to evaluate the ability of its generating fleet to provide adequate energy and capacity throughout the year, given the timing of renewables output, the ability to charge storage resources, and the potential for other correlated risks such as unit outages. This type of operational analysis is an emerging industry best practice consistent with guidance from EPRI and ESIG.

In everyday practice, as a member utility of MISO, the Company does not dispatch its generation directly to serve customer load but instead offers its units into the day-ahead and real-time markets. In modeling the reliability of the Duke Energy Indiana system, accurately modeling the interaction with the MISO market is important, and the Company seeks to continually align its analytical approach with developments in MISO and the broader industry. However, this Indiana-centric reliability modeling is intended to provide a baseline view of how different resource portfolios align with customer loads. The ultimate purpose is to ensure that future Duke Energy Indiana resource portfolios are contributing adequately to the MISO market and not placing an undue burden on the rest of the system. The future resource mix (and even capacity accreditation framework) of the broader MISO market is inherently uncertain, but through the Enhanced Reliability Evaluation modeling, the Company can ensure its proposed resource plans remain generally aligned with its own customer loads.

The Company has evaluated the relative performance of the Reference Worldview portfolios for the six generation strategies for the test year of 2035, as this year represents the time period after major retirement decisions have occurred and is also a period in which the production cost model results indicate that the portfolios would have large amounts of economic purchases. The portfolios are assessed on common reliability metrics including the industry standard Loss of Load Expectation ("LOLE") and Expected Unserved Energy ("EUE").

Reliability Metrics

In addition to the new resource adequacy modeling strategies discussed above, system planners and reliability modelers are realizing that *measurement* of reliability must change to properly characterize new system risks. Traditionally, the electric power industry has relied on the LOLE metric, which quantifies reliability risk as the expected number of days a system would be expected to curtail firm

[15] Based on the assumptions documented in MISO Inc., Loss of Load Expectation Study Report for Planning Year 2024-2025, April 2024, available at https://cdn.misoenergy.org/LOLE+Study+Report+PY+2024-2025631112.pdf.

load if probabilistic risks such as generator outages, renewables output, or load uncertainty were to resolve unfavorably.

LOLE remains a foundation of resource adequacy, but new metrics are being developed and evaluated to better illustrate how different resource portfolios can create risks of different magnitude, frequency, and duration as new resources carry different risk profiles. The most significant of these new metrics is EUE. Where LOLE measures the probability of experiencing an event, EUE (typically measured in megawatt-hours per year), captures the *magnitude* of these reliability events by summing up the total amount of firm energy curtailed. The use of EUE in evaluating power system reliability is becoming an industry norm. It is included as part of the ESIG multi-metric recommendation[16] and is also a component of the new PJM capacity accreditation framework.[17]

Additional metrics have been debated by the electric power industry, and others are in use in other parts of the world. However, for this IRP, the Company's enhanced reliability evaluation modeling is focused on the relative performance of the modeled portfolios on both LOLE and EUE as the two foundational metrics indicative of potential future risks.

As has been previously discussed, Duke Energy Indiana's integration into the MISO market is a core determinant of operational reliability for its customers. As such, the detailed modeling results documented in Appendix C are not focused on achieving an absolute value of LOLE or EUE for Duke Energy Indiana in isolation, and instead explore *changes* in the ability of future portfolios to align to customer load. To that end, results are presented on a normalized basis with the year 2028 (where the various portfolios experience little divergence) serving as the projected base level of performance, and the value of portfolios relative to this baseline presented as ratio (e.g., a portfolio with half as much EUE would score as a 0.5, and once with double the EUE would score as a 2.0).

The results of the Enhanced Reliability Evaluation performed for this IRP are presented in Chapter 4 (Candidate Resource Portfolios). Additional results and detail on modeling assumptions for the analysis can be found in Appendix C.

Future Advancements

Given the changing dynamics of the MISO market and the broader grid, the Company believes this type of analysis is an important addition to the 2024 IRP and intends to continue revising and improving the methodology based on stakeholder feedback, the future evolution of MISO's own probabilistic modeling activities, and broader advances in industry best practice. To that end, stakeholders have identified assumptions, which bear further investigation in future modeling activities, particularly around the load simulations used in the SERVM analysis. These include: (1) the shape and weather-

[16] ESIG, New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements, March 2024, available at https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024.pdf.

[17] For a more detailed discussion on the role of EUE in PJM's capacity accreditation framework, see FERC, Affidavit of Dr. Patricio Rocha-Garrido on Behalf of PJM Interconnection, L.L.C., October 13, 2023, available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=50081B32-EC59-C251-8CA2-8B2A96E00000.

response of potential future high-load factor large customers such as data centers, and (2) the treatment of electric vehicle loads and charging strategies. These and other potential determinants of modeled reliability will continue to be evaluated in future efforts to more accurately characterize potential risks to Duke Energy Indiana customers.

Appendix F: Supply-Side Resources

This Appendix details Duke Energy Indiana's approach to planning its existing and future supply-side resources fleet. To support a balanced energy transition, numerous resources are screened from a technical and economic perspective in the resource planning process. The resources available for selection in the 2024 Integrated Resource Plan ("IRP") reference case modeling include combined cycles ("CC"), combustion turbines ("CT"), solar, including solar paired with storage, stand-alone battery energy storage systems ("BESS"), wind, and advanced nuclear, including small modular reactors ("SMR") and advanced reactors, and additional technologies were contemplated as part of the 2024 IRP scenario analysis. As variable energy resources such as wind and solar become an increasing part of the generation resource mix, it is necessary that Duke Energy Indiana (the "Company") has a balanced approach to ensure a reliable and orderly energy transition.

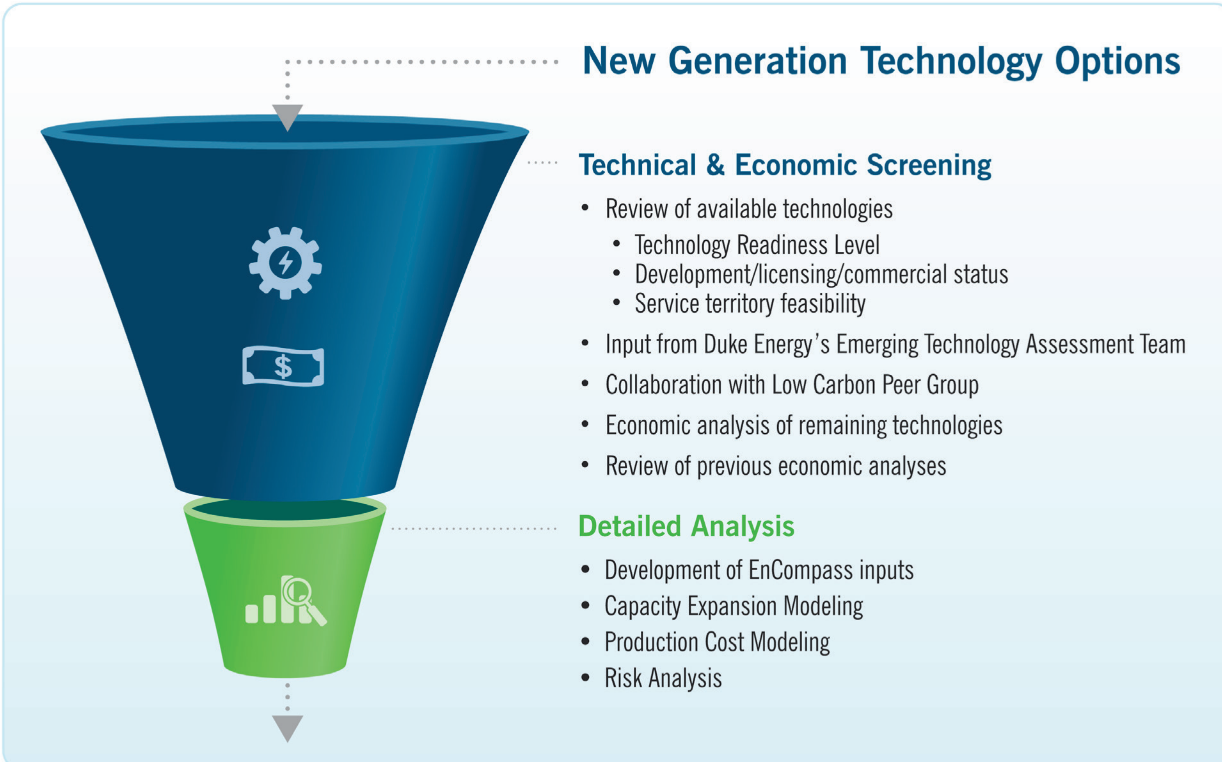
The Company's approach to long-term planning for each of these resource types requires detailed screening of available resources, procuring the necessary resources, understanding the diverse and complementary nature of each of the resource types, evaluating operational considerations, and understanding and mitigating execution risks.

Generation Technology Screening

Duke Energy Indiana screens generation technologies prior to performing detailed resource selection analysis to develop a set of supply-side resource options. Generating technologies are screened from both a technical perspective and an economic perspective as shown in Figure F-1 below.

Technical screening eliminates technologies that have technical limitations, commercial availability issues, or are not feasible in or near the Duke Energy Indiana service territory. Economic screening eliminates technologies that may be technically available but are clearly unable to compete economically with other technologies from a similar class (baseload, peaking/intermediate, variable, or storage). Resource technologies must be technically and economically viable to proceed to the detailed analysis phase of the resource plan development process. The Company compiles costs and operating characteristics for generic, representative units of resource types that pass through the screening process. These generic units are the resource options made available for selection in the EnCompass capacity expansion model, and further detailed analysis is performed through production cost and optimization modeling as well as sensitivity analysis. Detailed supply-side resource modeling assumptions are included in Chapter 3 (Key Assumptions) and Appendix C (Quantitative Analysis).

Figure F-1: Screening Considerations



Resource Types Technically & Economically Screened "In"

Natural Gas Resources – Combustion Turbines & Combined Cycles

Natural gas-fired generation is a proven and cost-effective dispatchable technology that has a long history of reliably serving Duke Energy Indiana customers with the ability to provide baseload, intermediate, and peaking energy needs in a flexible manner. The flexibility and reliability of the technology also aids system operators in ensuring a reliable system by providing ramping and dispatchability to support greater integration of intermittent renewable resources.

Dispatchable natural gas-fired resources continue to be an important part of maintaining low customer costs and high reliability. CTs have been and will continue to be a critical component of on-demand peaking generation. They are a fast ramping, dispatchable resource, which can help ensure system reliability as intermittent renewable growth increases on the system. The Company's existing CT units will continue to provide grid support where renewables and storage cannot, while new advanced class CC units will provide cost-effective energy and capacity to reliably replace aging coal-fired units and meet growing customer demand. As coal-fired units are retired, and the proportion of delivered energy from variable renewable resources increases, CC units will play an important role in the Company's diverse future portfolio by maintaining system stability as dispatchable resources that are available 24/7.

In addition to the CCs currently being evaluated, combined cycle with carbon capture and sequestration ("CCS") has been a technology under evaluation previously and may play a role in a carbon-constrained energy system. CCS technology continues to be tested throughout the United States as a low-carbon technology deployment option. Recently, the Department of Energy ("DOE") has selected/awarded numerous CCS studies and full-scale demonstrations. Duke Energy Indiana was awarded a cost share grant for one such study at the Edwardsport integrated gasification combined cycle ("IGCC") facility. In addition to the Duke Energy Indiana project, two other full scale natural gas-fired CCS demonstrations were also selected for potential DOE cost share grant funding. CCS is highly dependent on local and regional geology, and the site-specific information will dictate the potential to be an economic supply-side option. Retrofit of existing generation, both natural gas and IGCC, can extend the life of operating plants while moving toward lower CO_2 emissions goals. CCS will continue to be monitored by Duke Energy Indiana and evaluated as a decarbonization technology to meet future low-carbon requirements.

Solar

As Duke Energy Indiana's resource fleet continues to change and the need for clean energy resources grows, solar power will become increasingly important. While the capacity value of solar has been diminishing in the MISO capacity market, solar will still serve as a valuable energy resource that can be complemented by the capacity value provided by energy storage.

As Duke Energy Indiana procures solar and battery energy storage to meet the growing need for cleaner energy resources, the Company continues to evaluate the operational relationship between these resources. Storage paired with solar potentially provides an added benefit by way of capturing clipped energy to further increase the energy output of a solar resource while better aligning the output of the facility to the timing of customer needs.

Battery Energy Storage

Stand-alone energy storage is expected to play a role in ensuring that the Company meets its reserve obligations, incorporates increasing volumes of renewable energy and supports system reliability. Energy storage continues to become more economical and useful as additional variable energy resources are installed. 2024 IRP modeling included 4-hour lithium-ion ("Li-ion") battery storage as a technology selection option. In addition, long-duration energy storage (10-hour and 100-hour) was included for selection in the Aggressive Policy & Rapid Innovation worldview. The industry is observing continued declines in the installed cost of energy storage due to the growing market penetration of installed assets across the industry. Battery storage (4-hour) is expected to see decreasing costs as more units are installed across the United States. The increased flexibility of the system from energy storage is increasingly more important with the continued additions of solar and wind energy.

Duke Energy Indiana currently operates three small battery facilities that are dispatched into MISO. The Company continues to refine and develop the method these facilities are offered into the market. Operational learnings from these assets will be instrumental in optimizing future assets.

Duke Energy Indiana's initial efforts integrating BESS into its operations have allowed the Company to validate and adjust planned operations and maintenance strategies to include staffing and task organization, stocking spare parts, executing long-term service agreements with integrators, creating maintenance and outage schedules, automating cell voltage balancing, and forecasting cost. Strategies will be further refined and may be adjusted as Duke Energy Indiana's BESS fleet grows.

In addition to refining these strategies, Duke Energy Indiana is also observing how BESS is best operated as part of a diverse resource portfolio. Aside from the technology's ability to mitigate curtailment of renewable energy generation, the responsiveness of BESS provides flexibility to respond to system imbalances due to unexpected customer load or generation intermittency and contingency. This responsiveness stems from minimal required startup/shutdown processes, remotely operated dispatch and quick ramp times (particularly of Li-ion systems). In the sense of system planning, BESS can be incorporated as a part of a flexible strategy. Furthermore, augmentation projects can either increase megawatt-hour ("MWh") nameplate capabilities of an existing site or offset increased degradation stemming from usage higher than the amount envisioned at the time of initial construction. This capability is especially beneficial over a multiyear time horizon to enable deployment of increasing levels of renewable energy generation.

Wind

The United States onshore wind market continues to grow with approximately 140 gigawatts operational nationwide.[1] Wind energy complements solar generation by diversifying the portfolio renewable energy production profile, providing electricity overnight and during times of heavy cloud cover. The Company has taken reasonable steps to prepare for onshore wind development activities when it becomes prudent to pursue such projects, including retaining a leading consultant to perform a comprehensive siting feasibility study across MISO local resource zones four and six.

Nuclear

The United States advanced nuclear market continues to progress with many different reactor technologies under development, and Duke Energy Indiana's affiliates in the Carolinas are leaders in nuclear generation operation. As the Company continues to execute a balanced energy transition, retiring aging coal units and bringing highly efficient, cleaner natural gas and renewable resources online, advanced nuclear will remain a viable technological option for the later part of the 20-year IRP planning horizon.

Advanced nuclear includes two main design categories: light-water-cooled reactors ("LWR") and non-light-water cooled (non-LWR). Both designs are small and modular, and both are advanced in comparison to traditional nuclear plants operating today. The U.S. Nuclear Regulatory Commission ("NRC") refers to LWR designs as SMRs. The NRC refers to non-LWR designs as advanced reactors ("ARs"). ARs vary in size with reactors typically in the 50-350 megawatts electric ("MWe") range,

[1] Office of Energy Efficiency and Renewable Energy, U.S. Installed and Potential Wind Power Capacity and Generation, available at https://windexchange.energy.gov/maps-data/321.

though one design can be scaled to 1,200 MWe. SMRs use similar technology to the traditional reactors operating in the U.S. today; they use water as a coolant and low-enriched uranium as fuel. Some ARs will use novel fuels, with some designs using high-assay low-enriched uranium and coolants that have not been used by the commercial U.S. nuclear fleet. AR technologies offer some advantages over water-cooled reactors, including non-electric applications such as thermal storage, hydrogen production and process heat. SMRs are expected to face less regulatory and first-of-a-kind project risk since they are based on similar technology to today's fleet of large LWRs, use the same fuel type, and generally have proven supply chains. SMRs are expected to be available in the mid-2030s for Duke Energy Indiana. ARs are expected to be available in the late 2030s for Duke Energy Indiana and are being considered due to their flexible operational capabilities, including thermal storage.

Table F-1 below provides an overview of the next generation of advanced nuclear reactors.

Table F-1: Summary of Advanced Nuclear Reactor Types

Advanced Nuclear	
Small Modular Reactor	• Light-water-cooled, much like today's current commercial fleet. • Proven technology and furthest along from a licensing standpoint • Typically, 350 MWe or less
Advanced Reactor	• Non-light water-cooled – uses molten salt, helium gas or liquid sodium. • Operates at higher temperatures and typically at lower pressures. • Integrates well with variable renewable power like wind and solar. • Can be 50 MWe to 1,200 MWe, typically 350 MWe or less

Purdue University Nuclear Feasibility Study

In May 2023, Purdue University and Duke Energy jointly issued an interim report for the Small Modular Reactor and Advanced Reactor Feasibility Study (the "feasibility study"). This feasibility study was the result of a partnership that was formed to study the prospect of using SMRs or ARs to provide the electricity, heating, and cooling needs of the Purdue campus and excess power to the Indiana grid. The feasibility study determined that SMR and AR technology is a potential solution to achieving zero emissions at Purdue University's West Lafayette campus and that further exploration should be undertaken. Importantly, for SMR or AR deployment to be successful, the feasibility study puts forward policy and funding recommendations to advance research, workforce development, technology demonstration, siting, regulatory reform, and tax issues relevant to progressing nuclear energy.

Siting

A nuclear siting study is being performed by an independent firm for the Duke Energy Midwest service territories. The approach is similar to a previous 2011 study utilizing Electric Power Research Institute ("EPRI") and NRC guidance. The multifaceted approach considers energy communities as defined by the Inflation Reduction Act ("IRA") along with environmental and physical characteristics such as cultural resources, wildlife areas, seismology, topography, geology, and hydrology. The results will inform potential locations that are suitable for nuclear power plant construction, without having to presuppose a reactor technology. The study is targeted to be completed in December 2024.

The process to bring an advanced nuclear plant online typically spans approximately ten years. A utility must develop either the construction permit and operating license application, or a combined license application, for submittal to the NRC. Depending on the licensing pathway chosen, NRC reviews can take up to six years. A three- to four-year construction period is estimated, followed by fuel load and startup testing. Duke Energy Indiana's affiliate, Duke Energy Carolinas, has chosen a site in Belews Creek, North Carolina, to obtain an early site permit ("ESP") for a potential new SMR. The ESP allows Duke Energy Carolinas to resolve environmental and site safety characteristic issues at the site prior to choosing a reactor technology or making a decision to move forward with building a plant. Duke Energy Indiana will continue to monitor the progress of this project and others in the industry.

Policy Support

The DOE has aggressively supported and provided funding for the development of advanced nuclear technologies, with a goal of ensuring that the U.S. remains the leader in global nuclear technology. The largest program to date is the Advanced Reactor Demonstration Program ("ARDP"), which in 2020 announced awards for 50% cost-share funding of two AR designs and five smaller risk reduction awards. The two AR demonstration projects, receiving approximately $1.3 billion each, are the X-energy Xe-100 project to be built for Dow Chemical in Seadrift, Texas, and the TerraPower Natrium project to be built at a PacifiCorp retiring coal plant site in Kemmerer, Wyoming. The Xe-100 reactor is a high-temperature gas reactor, which uses helium for cooling, and the Natrium reactor is a sodium fast reactor, which uses liquid sodium for cooling. The Xe-100 project and the Natrium project are scheduled to be operational by 2029 and 2030, respectively.

Duke Energy partnered with TerraPower in the ARDP to support the design and construction of the first Natrium reactor. Duke Energy's role is primarily to provide consulting and advisory in-kind services to TerraPower. Partnering with TerraPower and PacifiCorp on this project will allow Duke Energy to be involved early in the development of this new technology and to gain additional experience and insights with this new design. Additionally, a small team of Duke Energy personnel are embedded in the TerraPower team, providing operations and training program support.

The IRA introduced significant tax credits for both existing nuclear plants and new advanced reactors (i.e., any new plant that produces zero greenhouse gas emissions that is placed into service after December 31, 2024). Advanced nuclear plants, with reliable, clean, and zero-carbon generation, qualify for this technology-neutral Production Tax Credit ("PTC") or Investment Tax Credit ("ITC"). Under the Company's IRA planning assumptions, as addressed in more detail in Chapter 3, SMRs and ARs would be eligible for either the PTC or ITC, and it has been preliminarily determined that the ITC results would be more beneficial. The PTC is based on the amount of electricity produced and sold (dollars per MWh) and is available for a ten-year period beginning on the date that the facility is placed into service. The ITC is based on the investment in building a qualified facility (dollars as a percent of costs) and is effective in the year the facility is placed in service. See Chapter 3 and Appendix C for more detail on 2024 IRP modeling assumptions related to IRA tax credits.

The state of Indiana also has favorable policy related to SMRs and requires balancing the Five Pillars of energy policy – reliability, resiliency, stability, affordability, and sustainability – as a utility puts together its long-term resource plan and requests approval of new generating resources. Indiana law further treats SMRs as clean energy resources, providing incentives such as timely cost recovery, including recovery during construction.

Operational Considerations

SMRs and ARs have many benefits that provide improved construction and even safer operation as compared to traditional nuclear technology. The modular design of these new reactors allows for more off-site construction and shorter production timelines. Designs are smaller and simpler, meaning less capital investment per unit and more flexibility, allowing for greater ability to match power output to system loads (i.e., load follow). In addition, this next generation of nuclear plants offers safety improvements. Inherent safety features in advanced designs include passive shutdown and self-cooling through natural circulation, meaning the systems can shut down and cool the reactor for days with no operator intervention.

ARs have additional unique benefits. These units operate at higher temperatures, increasing thermal efficiency. This feature allows the plants to provide more flexibility to support operations such as hydrogen production, process heat applications, and desalination projects. Some AR designs have thermal storage systems, which enable the plants to increase power output during periods of high demand or when variable renewable energy is unavailable. Some ARs also have increased safety features with designs operating near atmospheric pressure, and certain AR designs use a more robust fuel type. These features result in the ability to safely site plants closer to load centers by requiring smaller emergency planning zones.

Technically & Economically Excluded Resource Types

The Company determined that certain resource technologies were ineligible to be included in the 2024 IRP analysis due to technical or economic infeasibility. The list of technologies being evaluated by the Company but excluded due to technical or economic reasons is as follows:

Coal

While coal generation has historically been a suitable baseload resource, increasing environmental regulations have challenged the economics and viability of pursuing new coal resources.

Geothermal

Geothermal resources have traditionally been enabled by geology in the western half of the United States.[2] Advanced geothermal covers a variety of technologies but typically includes closed-loop systems and deep borehole drilling to reach greater depths with higher temperatures. Recent developments in deep direct-use geothermal may expand the applicability of geothermal into some of the least favorable geological formations. These technologies have not yet reached commercial status, and the Company continues to monitor ongoing pilots and demonstrations for potential future application within its service territory.

Pumped Storage Hydropower

Pumped Storage Hydropower ("PSH") generates energy by moving water between two reservoirs at different elevations. PSH installations are greatly dependent on regional geography and face several challenges including environmental impact concerns, a long permitting process, and a relatively high initial capital cost. There are no suitable sites for PSH in the Duke Energy Indiana service territory.

Offshore Wind

Offshore wind was eliminated from selection as there are no suitable offshore locations for Indiana.

Solar Steam Augmentation

Solar Steam Augmentation systems utilize solar thermal energy to supplement a Rankine steam cycle such as that in a fossil generating plant. The supplemental steam is integrated into the steam cycle and supports additional MW generation similar in concept to the purpose of duct-firing a heat recovery steam generator. Instead of collecting energy through solar panels, solar steam augmentation utilizes mirrors to concentrate solar energy. This process requires specific weather conditions, favoring hot, dry locations, and most current installations are in deserts like the North American Southwest. The Company will continue to monitor developments in solar steam augmentation and any changes to the technology in the future that warrant a change to the current assessment.

Supercritical Carbon Dioxide

Supercritical carbon dioxide ("sCO_2") Brayton Cycle/Allam Cycle utilizes carbon dioxide ("CO_2") as the working fluid, replacing the air (Brayton Cycle) or water (Rankine Cycle) as used in traditional power

[2] National Renewable Energy Laboratory, Geothermal Resources of the United States, February 22, 2018, available at https://www.nrel.gov/gis/geothermal.html.

generation systems. Just above the critical point, CO_2 is liquid-like, which dramatically reduces compression/pumping power (and cost) compared to air and nitrogen. Some sCO_2 Brayton cycles for fossil-fuel plants might achieve 100% CO_2 capture and zero emissions of conventional pollutants with little or no efficiency or capacity penalty. However, a low-CO_2-emitting sCO_2 power cycle facility would require carbon capture, transportation, and storage (or, alternatively, utilization). This technology remains in the demonstration stage with some early pilot issues requiring correction before the technology reaches commercial status. This technology has the potential to be an improved option compared to a traditional natural gas combined cycle plant with CCS due to the advantages named above, but both the commercial status of the technology needs to progress and the viability of CO_2 sequestration within Indiana needs to be proven. The Company will continue engaging in industry efforts to follow the technology's status and determine the appropriate timing for sCO_2 power cycle to be considered as a selectable technology.

Emerging Energy Storage Technologies

Additional energy storage technologies continue to be developed and pursued by a variety of industries and companies. The range of technology types is vast and includes non-lithium-ion batteries, mechanical storage, thermal storage, and variants of pumped hydro storage. Although some of these emerging storage technologies passed the technology screening, the majority are still in a pre-commercial status. These technologies continue to be studied as future options. The growing list of potential future energy storage options includes lead-acid batteries, sodium-sulfur batteries, metal-air batteries, subterranean pumped storage, gravitational energy, hydrogen, flywheel energy, compressed air energy storage, liquid air energy storage, and chilled water, molten salt, silicon, concrete, sand, and phase change storage. Duke Energy Indiana will continue to monitor the developments and pilots of the various storage options to determine which designs have reached commercial status. The Company has included two representative long-duration energy storage options for consideration in the Aggressive Policy & Rapid Innovation worldview as described in Appendix C.

Generic Unit Summary

Sources Used to Develop 2024 Generic Unit Technology Costs

Duke Energy Indiana performs a robust evaluation of a variety of data sources when determining the costs and characteristics of each technology passing the technical screening. The primary resources used are an engineering study produced by the engineering firm, Burns & McDonnell, and a suite of renewable energy and energy storage data tools created by Guidehouse, a consulting firm. Burns & McDonnell has construction experience in the energy industry and its recent projects lend credibility to estimating generic technology costs. Guidehouse prepares the renewable and storage tools to allow for flexibility in estimating a wide range of resource options and configurations. Both companies prepare cost estimates and estimating tools specific to Indiana and the Midwest region based on labor rates, geographical information, and other region-specific factors. Duke Energy Indiana also leverages its own internal data and expertise to inform generic resource costs and characteristics.

Beyond its primary sources, the Company comprehensively reviews other reputable industry resources in this intensive process. EPRI has a program dedicated to techno-economic analysis of energy systems and delivers a variety of reports that are useful when evaluating technology costs. EPRI also maintains the TAGWeb database, which provides technology costs for all pertinent supply-side resources and is updated annually for most technologies under consideration. EPRI information directly informed select generic technology costs. Additional publicly available resources are carefully considered when finalizing cost data, including the National Renewable Energy Laboratory's Annual Technology Baseline, the Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO"), and Lazard's Levelized Cost of Energy ("LCOE"). These resources, along with various reports from Wood Mackenzie, are all considered when developing and refining generic technology costs. For example, the Company leverages EIA's AEO technology inflation factors when establishing the long-term technology cost estimates.

Cost Considerations

Costs continue to experience significant volatility, and the technology costs used for 2024 IRP modeling reflect this trend. Although material prices appear to be stabilizing, there is a significant lag between market data and real-time installations. The 2024 IRP cost projections have shown significant increases from past IRPs across all supply-side technology options due to these cost pressures. To confirm that the Company's generic unit cost forecasts are aligned with the current market, Duke Energy Indiana conducted a benchmarking exercise in which it compared bid prices from the ongoing 2024 All-Source Request for Proposal to the generic cost forecast for the same technology and in-service year.

Tax Credits

IRA tax credits also have a significant impact on the all-in costs of certain resource types. Importantly, the overnight costs presented herein do not reflect the value of tax credits. IRA tax credits are awarded after installation is complete and the resource is in service, and therefore impact the all-in cost rather than the expected overnight capital cost of a technology. All relevant tax credits are included as distinct inputs to the EnCompass model. The inclusion of these tax credits in the 2024 IRP analysis is discussed in Chapter 3.

Capital Cost Forecast

A capital cost forecast is developed, projecting the overnight capital cost of each supply-side resource in each year of the planning period. Duke Energy Indiana's forecast uses a combination of 2024 costs, Guidehouse price decline curves, EIA AEO technology forecast factors and other near-term adjustments (e.g., adjustment of near-term contingency). This information is used to create technology-specific inflation rates used to project each technology cost through the 20-year planning period. Since the EIA did not release AEO technology forecast tables for 2024, the 2023 tables were normalized to 2024 values to maintain the integrity of the curves as publicly available information.

Continued Improvement of Generic Unit Cost Development

The Company has worked with Guidehouse and Burns & McDonnell to improve processes, has incorporated more publicly available data into its modeling cost assumptions, and has blended proprietary data from multiple sources to allow for most of the generic technology costs to be shared publicly. This enhanced approach to developing 2024 generic unit costs has enabled the Company to provide more detailed and transparent content during stakeholder meetings and within the 2024 IRP document.

2024 Generic Unit Technology Costs

Selectable resources in the 2024 IRP are summarized in Figure F-2 below. The 2024 overnight capital costs for selectable technologies are shown below in Table F-2. To preserve confidentiality of specific turbine configuration costs, a range is given for simple cycle and combined cycle units. This table also includes the year in which the technology is first available for selection by the model, indicating the point at which the technology could be in service and contributing to the resource portfolio (project activities and construction would begin prior to that date).

Expressed in 2024 dollars, these costs represent the estimated overnight cost of a technology installation if the project were to begin in 2024, thus exclude inflation that may occur prior to project start and any interest accrued during construction. Overnight costs for future in-service years are projected using technology-specific inflation curves based on an assumed general inflation rate and the expected technology learning curve through the modeling period. The 2024 overnight costs are the starting point for these forecasts. Since resources are installed at a future time, the modeled cost for each technology will reflect inflationary and interest impacts to the overnight costs based on the installation year(s) determined by the model.

Figure F-2: Selectable Supply-Side Resources in the 2024 IRP

NATURAL GAS

- 2x1 Advanced Class Combined Cycle
- 1x1 Advanced Class Combined Cycle
- 2x1 Advanced Class Combined Cycle with CCS
- Multi-Unit Advanced Class Combustion Turbine

RENEWABLES

- Solar Photovoltaic ("PV") Bifacial Single Axis Tracking ("SAT")
- Solar PV Bifacial SAT + 4-Hour Lithium-ion Battery Storage
- Onshore Wind

STORAGE

- 4-Hour Lithium-ion Battery Storage (Standalone and Paired with Solar)
- 10-Hour Long Duration Energy Storage
- 100-Hour Long Duration Energy Storage

NUCLEAR

- Small Modular Reactor
- Advanced Reactor with Thermal Storage

Table F-2: Generic Unit Overnight Technology Capital Costs for Projects in 2024 Dollars

Technology	MW per Unit	Cost (2024$/kW)	First Year Available	Notes
2x1 Advanced Class Combined Cycle	1,438	$1,100-$1,250	2032	Includes duct firing kW, high firm transport O&M adder, low near-term cost decline
1x1 Advanced Class Combined Cycle	719	$1,450-$1,550	2030	Includes duct firing kW, high firm transport O&M adder, low near-term cost decline
2x1 Advanced Class Combined Cycle with CCS	1,215	$3,750	2035	Unavailable until mid-2030s, includes duct firing kW, high firm transport O&M adder, low near-term cost decline
Multi-Unit Advanced Class Combustion Turbine (Simple Cycle)	425 (per turbine)	$1,000-$1,200	2031	Moderate firm transport O&M adder, low near-term cost decline
Small Modular Reactor	300	$11,150	2037	Unavailable until mid-2030s, low near-term cost decline
Advanced Reactor w/ Thermal Storage	300 (Nuclear) 150 (Storage)	$12,300	2039	Unavailable until late-2030s, moderate near-term cost incline
Onshore Wind	50	$2,050	2028	Moderate near-term cost decline
Solar PV – Bifacial Single Axis Tracking (“SAT”)	50	$1,850	2027	Moderate near-term cost decline
Solar PV Bifacial SAT + 4-Hour Li-ion Storage	50 (Solar PV) 25 (4-hr Li-ion)	$2,950	2028	High near-term cost decline
4-Hour Li-ion Storage	50	$2,300	2028	High near-term cost decline
10-Hour Long-Duration Energy Storage[1]	100	$2,300	2030	Moderate near-term cost decline
100-Hour Long-Duration Energy Storage[1]	100	$2,550	2032	Moderate near-term cost incline

Note 1: Long-duration energy storage is a selectable resource in the Aggressive Policy & Rapid Innovation scenario only. See Chapter 3 for more detail.

The overnight costs shown in Table F-2 above are rounded to the nearest $50/kW and include a generic interconnection adder, expected owner’s costs, and a contingency factor. Costs are presented in terms of dollars per kW of installed capacity, without adjusting for resource accreditation.

Recent inflationary pressures and supply chain challenges create significant uncertainty around the future costs of materials, labor, components, and other items included in technology cost estimates.

Forecasted technology cost declines are generally more aggressive than in previous analyses to reasonably account for future easing of inflation. The Company will continue to monitor and evaluate the many dynamics impacting technology costs and update cost curves accordingly in future proceedings.

Benefits and Challenges of Levelized Cost of Energy

LCOE is a metric that can be used to compare generation resources to determine the lowest cost over a set period under a specified set of assumptions. The LCOE considers the full cost of the asset including capital, fuel, and operating and maintenance expenses, as well as the expected capacity factor and operating life of the asset. However, LCOE has limitations when comparing technologies, which can create uneven results when assessing different use cases (e.g., baseload vs. peaking), capacity values (e.g., effective load carrying capability) and/or operating life (e.g., 15 vs. 35 years). Although LCOE can be a useful metric for cost analysis, a full evaluation of multiple sources, as well as costs and usage expectations via capacity expansion and production cost modeling is needed for robust resource planning. The 2024 IRP reflects this robust evaluation, and the advancements made to technology cost development since the 2021 IRP.

Appendix G: Competitive Procurement Process

Introduction to Competitive Procurement Process

Duke Energy Indiana (or the “Company”) leverages competitive procurement processes when sourcing services, materials, equipment, and generation resources. These processes can be structured in many ways, but all are focused on sourcing the best service or product to fill the system’s need in a competitive bidding environment. Competitive procurement benefits customers as it identifies the resources available to the utility that offer the highest value to Duke Energy Indiana’s customers considering both price and non-price factors.

With respect to generation resources, Indiana law emphasizes the importance of competitive procurement. Indiana Administrative Code (“IAC”) 8-1-8.5-5(e) outlines the requirements for competitive procurement when a utility proposes to construct a facility with a generating capacity of more than 80 megawatts (“MW”). Before granting a Certificate of Public Convenience and Necessity (“CPCN”) for such a facility, the Indiana Utility Regulatory Commission (or the “Commission”) must find that the estimated costs are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts. Additionally, the utility must allow third parties to submit firm and binding bids for the facility's construction, with ownership vesting in the utility once it becomes commercially available. The Commission is also required to consider whether the applicant has solicited competitive bids for purchased power capacity and energy from alternative suppliers. Of note, this statute does allow the utility and its affiliates to participate in the bidding process. Moreover, when determining whether to approve a project as a "clean energy project" under IAC 8-1-8.8-11, the Commission has, in past cases, considered the use of competitive solicitation as set forth in IAC 8-1-8.5.

To take advantage of the many benefits of competitive procurement, Duke Energy Indiana has developed a detailed market solicitation process in the form of a Request for Proposal (“RFP”) that the Company uses when it needs additional generation resources. Typically, the types, capacity targets, and time frame of the generation sought in an RFP is informed by the Company's current Integrated Resource Plan (“IRP”).

Request for Proposals

Duke Energy Indiana’s resource plan could identify the need for additional intermittent resources or non-intermittent resources or both. When the plan calls for both, an all-source RFP is issued, which is effectively a non-intermittent RFP and intermittent RFP issued as part the same solicitation. This was the case for Duke Energy Indiana's 2022 RFP and 2023/2024 RFP, both of which are described in detail further below.

Intermittent & Non-Intermittent Resources

Non-intermittent resources are dispatchable and are typically fueled by natural gas, coal, nuclear, geothermal, batteries, or steam from industrial processes. Intermittent resources are not dispatchable and are typically solar and wind with both possibly paired with batteries. There are distinct differences between how each resource type can help satisfy the needs of the overall portfolio, and they are not completely interchangeable. There are times when the sun is not shining, the wind is not blowing, and natural gas can be challenging to procure during winter peak times. There are ways of hardening these assets by adding battery storage or backup fuel supplies, but a well-diversified portfolio is the best hedge against unknowns.

Another consideration in an RFP is the time frame for which the generation resources are being solicited. The development time of the various resources is the main factor that influences this. For intermittent resources, development and construction time is typically shorter than it is for non-intermittent resources. Of course, an existing asset that has already been developed and/or constructed may be available sooner.

Transaction Structures & Deal Types

There are several transaction structures and deal types, but most are broadly characterized as power purchase agreements ("PPA") or utility ownership, including asset transfers, build-transfers, and self-developed.

Power Purchase Agreements

The project is fully completed by a third party who maintains ownership and operates and maintains the asset. The capacity and energy are contracted to the utility over an agreed upon term, typically at a cost based on the energy production. This could be an existing asset or a proposed new asset.

Asset Transfer

The project is partially completed by a third-party developer and then sold to the utility company. These assets typically include overall project design, site control in the form of lease agreement or options, and a transmission interconnection agreement or study queue position. Additionally, they may include agreements with equipment suppliers and engineering/construction companies. It is the responsibility of the utility company to finish the project, put it in service, and own, operate, and maintain the asset after the sale.

Build-Transfers

The project is fully completed by a third-party developer and sold to the utility company. The utility may include design specifications to ensure the project meets certain quality and reliability standards. This could be an existing asset or a proposed new asset. Once the project is ready to be put in service, it is sold to the utility, who then owns, operates, and maintains it.

Self-Developed

The project is developed by the utility company's internal development teams, with the assistance of external technical vendors. The utility develops, owns, operates, and maintains the asset.

Role of an Independent Third-Party Administrator

Duke Energy Indiana utilizes independent third-party administrators in its RFP processes to ensure they are executed in a fair and unbiased manner. The administrator:

- Acts as RFP manager by facilitating the RFP process.
- Reviews proposals to ensure they conform to all requirements.
- Independently evaluates bids according to pre-specified criteria.
- Manages bidder communication and marketing.
- Provides utility with a ranked list of projects by type to consider for advancement.

To the extent required, the administrator may support additional due diligence conducted prior to final selections and contracting.

Scoring Bids: Evaluation Criteria & Weighting

To compare bids for a particular resource type, Duke Energy Indiana and the independent third-party administrator develop certain evaluation criteria and weighting for which each is scored. The criteria are organized in price and non-price components, with subsets of each.

- **Economic Value**: The economic value, on a net present value ("NPV") basis, is calculated over a fixed planning horizon for all assets. The economic analysis reflects all expected costs related to the bid. The project-level analysis is based on data submitted with the bids, standard assumptions for key commodity considerations, and may reflect adjustments for material uncertainties associated with a bid.

- **Reliability and Delivery**: The asset reliability and deliverability evaluation include an assessment of facility age and performance, fuel risk and fuel security. Facility performance is based on the accreditation performance. Fuel reliability considers fuel availability risk and price volatility. Due to impacts of environmental rules, scoring of thermal units will reflect a preference for newer generation machines under the reliability metric.

- **Development**: Development risk considers how many key development milestones have been met as well as the development experience of the potential counterparty.
- **Asset Specific Benefits / Risks**: Asset specific benefits and risks consider individual, unique, project-level risks associated with an individual project or counterparty. Projects are evaluated based on community benefits, certain social justice goals, minority- and women-owned business considerations, unique environmental considerations, specific regulatory risks, and other considerations.

How Results are Used

The main purpose of an RFP is to identify attractive resources the Company can move forward with into the negotiation phase for potential procurement. If negotiations are successful, the next step would be to file a CPCN with the Commission. As part of that filing, Duke Energy Indiana will need to show that the resource provides the best balance of benefits to customers as compared to other available resources. Additionally, the RFP informs the regional market costs for available near-term resources for subsequent resource planning.

2022 All-Source Request for Proposal

Duke Energy Indiana's 2021 IRP's Preferred Portfolio identified the need for new capacity resources in the near-term. Based on the expected time frame of available resources in the market, the period of Midcontinent Independent System Operator ("MISO") 2023/2024 to 2027/2028 Planning Year was selected for the solicitation. Within that period, the Preferred Portfolio identified the need for both intermittent and non-intermittent resources that, in turn, informed the RFP targets for each that are shown in Table G-1 below.

Table G-1: Duke Energy Indiana's 2022 RFP Targets

Resource Class	ICAP Target	In-Service Target Date
Intermittent	1,075 MW	6/1/2023 – 6/1/2027
Non-Intermittent	1,221 MW	6/1/2023 – 6/1/2027

Note: Installed Capacity ("ICAP")

Overall Structure

Third-Party Administrator

In the fall of 2021, Duke Energy Indiana retained Charles River Associates ("CRA") to support Duke Energy Indiana's long-term resource planning process through the design and execution of an all-source RFP process. As part of CRA's role as the third-party administrator, they assisted in the design, administration and bid evaluation of the RFP process. CRA's activities included:

- Working with the Company to develop IRP resource requirements into a clear definition of capacity needs.
- Working with Duke Energy Indiana to finalize threshold participation requirements.
- Proposing and finalized bid evaluation criteria including the relative weighting of parameters.
- Managing pre-RFP marketing and conducted a bidder information session.
- Coordinating bidder communication and ensured all bidders were afforded equal access to process information.
- Receiving and reviewing all bids independent of Duke Energy Indiana and interfacing with Duke Energy subject matter experts in a manner designed to preserve bidder confidentiality.
- Reviewing, evaluating, and scoring each bid in accordance with the evaluation criteria.

Facility Parameters

Table G-2 below lists the resources and parameters included in the 2022 RFP.

Table G-2: 2022 RFP Facility Parameters

Resource Types	Minimum Installed Capacity (Nameplate)
Intermittent	
Solar	50 MW
Wind	175 MW
Hybrid Storage Component	25 MW (4-hour duration)
Non-Intermittent[1]	
Thermal	25 MW
Standalone storage	25 MW (4-hour duration)

Note 1: Coal resources were not considered.

Location Restriction

MISO Local Resource Zone 6

Transaction Structures and Deal Type

PPAs with a minimum term length of five years, asset sales, build-transfers, and self-developed.

Evaluation Criteria and Weighing

Based on a 1,000-point scale:

- **Economic Value (300 points)**: The economic component of the RFP evaluation analyzed the projected costs and market value of outputs associated with each capacity asset to derive a net capacity cost on a per MW unforced capacity basis. The value for each asset was determined based on cost and performance information for each facility consistent with individual RFP responses and Duke Energy Indiana's internal IRP modeling of the MISO market.

- **Capacity Asset Reliability and Deliverability (300 points)**: Asset reliability and deliverability was based on information provided in response to the RFP with respect to transmission risk; age; recent and projected outage rates at the facility; and fuel security and reliability. All bids started with the maximum 300 potential points for this category with points deducted for less desirable characteristics.

- **Development (200 points)**: Development status considered both interconnection and site control related milestones achieved to date for a project that has not reached its commercial operation date ("COD"). In addition, proposals were scored based on the experience of the developers sponsoring the project's development.

- **Asset-Specific Benefits/Risks (200 points)**: This category was intended to capture unspecified capacity asset risk that may be highlighted by a bidder or identified during the proposal review. The Asset-Specific Benefits/Risks category was used to adjust the overall scoring in cases where there is a material risk identified that may compromise the future operating performance of the asset, create a material uncertainty with the cost of asset to Duke Energy Indiana or its customers, significant regulatory uncertainty, or in cases where the bid requires Duke Energy Indiana to assume material and uncertain liabilities upon acquisition of the asset.

Stakeholder Process

Charles River Associates conducted an RFP stakeholder information session on January 28, 2022. The high-level structure and scope of the RFP was shared with interested parties. Participants that were interested in detailed information were requested to execute a non-disclosure agreement with the Company.

Schedule & High-Level Results

Table G-3 below displays the 2022 RFP schedule. Table G-4 below provides the 2022 RFP High-Level Results.

Table G-3: 2022 RFP Schedule

2022 RFP Schedule	
Task	**Date**
Submitted 2021 IRP to the Commission	12/15/2021
Notification/Meeting Notice for Stakeholder Information Session	1/21/2022
Conducted Stakeholder Information Session	1/28/2022
Distributed Primary RFP Documents to Stakeholders with Signed NDAs for Feedback	1/31/2022
Stakeholder Feedback Deadline	2/14/2022
Issued RFP	2/21/2022
Prequalification Documents Due	3/14/2022
Intermittent Proposals Due	4/18/2022
Non-Intermittent Proposals Due	5/2/2022
Bid Evaluation	May – July 2022
Charles River Associates – Opinion Letter and Ranked Order List	7/20/2022 & 12/14/2022
Additional Due Diligence and Definitive Agreements Signed with Bidders	Started in Q3 2022

Table G-4: 2022 RFP High-Level Results

Resource Types	Total Projects	Total Net Capacity (Installed Capacity)
Intermittent		
Solar	14	2,180 MW
Solar + Storage	2	250 MW
Wind	0	0 MW
Non-Intermittent		
Thermal	2	1,714 MW
Standalone storage	7	1,057

Tranche-Level Data

Charles River Associates provided tranche-level data based on the bid results to Duke Energy Indiana's IRP modeling team, which were used to inform the cost and availability of resources in the IRP modeling as seen in Table G-5 below, which also provides Variable Operations and Maintenance ("VOM") and Fixed Operations and Maintenance ("FOM") costs on a kilowatt ("kW") per year basis.

Table G-5: 2022 RFP Tranche-Level Data

								PPA Information		Asset	Storage		
Tranche Identifier	Technology	Deal Structure	Location	In-Service	MW	VOM ($/MWh)	FOM ($/kW-yr)	$/MWh	Term	$/kW	MW	Duration	$/kW-mo
Solar 1	Solar	Asset	LRZ6	2025-2027	800	–	$16.00	–	–	$1,503	–	–	–
Solar 3	Solar	Asset	LRZ6	2026-2027	500	–	$16.00	–	–	$1,760	–	–	–
Solar 2	Solar	PPA	LRZ6	2025-2027	680	–	–	$54.00	20	–	–	–	–
Solar 4	Solar	PPA	LRZ6	2025-2027	850	–	–	$58.00	20	–	–	–	–
CC 1	Combined Cycle	Asset	LRZ6	2027	1,005	$2.00	$13.75	–	–	–	–	–	–
CC 2	Combined Cycle	Asset	LRZ6	2026	709	$2.00	$13.75	–	–	–	–	–	–
Storage 1	Storage	PPA	LRZ6	2025-2027	700	–	–	–	20	–	700	4	$14.33
Storage 2	Storage	PPA	LRZ6	2026-2027	274	–	–	–	20	–	274	4	$12.49
Storage 3	Storage	Asset	LRZ6	2025-2027	50	–	$26.00	–	–	–	50	4	–
Storage 4	Storage	Asset	LRZ6	2025-2027	33	–	$26.00	–	–	–	33	4	–

Speedway Solar Power Purchase Agreement

The Speedway Solar PPA was identified as part of the 2022 RFP process. The project is being developed in Shelby County, Indiana, and will have an installed capacity of approximately 199 MW. The Speedway Solar PPA provides Duke Energy Indiana with 100% of the electrical output of Speedway Solar over a term of 20 years, beginning at the commercial operation date, which is estimated to be in September 2025. The purchase is a bundled product, consisting of the solar energy project's production, capacity, and environmental attributes.

The Speedway Solar PPA is consistent with Duke Energy Indiana's Preferred Portfolio from the 2021 IRP. That plan included the addition of 150 MW of solar-powered generation in 2023, with another 250 MW being added in 2024 and 200 MW in 2025.

In the spring of 2023, Duke Energy Indiana performed updated modeling to assess the impacts of significantly changed circumstances since December 2021, including MISO's implementation of the Seasonal Accreditation Capacity construct and the passing of the Inflation Reduction Act ("IRA") at the federal level. The updated modeling allowed solar generation that was reflective of the prices of the RFP bids to be selected, and the resulting portfolio included the addition of 320 MW of solar generation each in 2025 and 2026. Duke Energy Indiana also updated data for its 2024 Spring Load Forecast, commodity costs, and technology costs.

The Speedway Solar PPA is consistent with the pricing modeled in the 2021 IRP; the updated modeling specifically included several price tranches of PPA solar based on the results of the RFP. The Speedway Solar PPA price is reflective of the first tranche of PPA solar included in the updated portfolio in 2025.

On June 15, 2023, Duke Energy Indiana filed a Verified Petition with the Commission requesting approval of a solar PPA between Duke Energy Indiana and Ranger Power, LLC for Speedway Solar as a clean energy project under Indiana Code 8-1-8.8-11, associated timely cost recovery for the Speedway Solar PPA, and other accounting and ratemaking authority. On September 11, 2023, the Commission approved Duke Energy Indiana's request.

Continued Due Diligence on Other Projects

There are multiple high-scoring projects bid into the 2022 RFP that Duke Energy Indiana is still considering. These projects are currently in the MISO Generation Interconnection Queue Study process with undetermined final transmission system network costs. The MISO Study process has been delayed several times since the issuance of the RFP and is currently under reform. This factor in turn delays Duke Energy Indiana's due diligence. Duke Energy Indiana will reevaluate the economics of those projects once those costs have been finalized.

2023/2024 All-Source Request for Proposal

In the fall of 2023, Duke Energy Indiana performed updated modeling and engaged with stakeholders to incorporate the Environmental Protection Agency's ("EPA") newly proposed Clean Air Act Section 111 rules in addition to MISO's accreditation construct changes and the IRA. The near-term resource needs identified in the Fall 2023 modeling were used to inform the 2023/2024 All-Source RFP. The time period of MISO 2025/2026 to 2032/2033 Planning Year was selected for the solicitation and included both intermittent and non-intermittent resources. Table G-6 below shows the resulting RFP targets.

Table G-6: Duke Energy Indiana's 2023/2024 RFP Targets

Resource Class	ICAP Target	In-Service Target Date
Intermittent	2,500 MW	12/31/2032
Non-Intermittent	2,500 MW	12/31/2032

Overall Structure

Third-Party Administrator

In the fall of 2023, Duke Energy Indiana again retained Charles River Associates as the third-party administrator, this time for the 2023/2024 All-Source RFP. CRA's role in this RFP was identical to their role in the 2022 RFP. Table G-7 and Table G-8 below introduce the RFP facility parameters and a summary of location preferences.

Facility Parameters

Table G-7: 2023/2024 RFP Facility Parameters

Minimum Installed Capacity (Nameplate)	
Intermittent	
Solar	50 MW
Wind	100 MW
Hybrid Storage Component	25%, 35% or 50% of paired renewable MW (4-hour duration minimum)
Non-Intermittent[1]	
Thermal	25 MW
Standalone storage	25 MW (4-hour duration minimum)

Note 1: Coal resources were not considered.

Location Preferences

Table G-8: 2023/2024 RFP Summary of Location Preferences for Non-Intermittent Resources

Preference	Location	Restrictions
Non-Intermittent		
1st Choice	Inside of Duke Energy Indiana Local Balancing Authority ("LBA")	No additional restrictions
2nd Choice	Inside of MISO Zone 6, Outside Company's LBA	No additional restrictions
3rd Choice	Inside of MISO Zone 4 or 7	No additional restrictions
4th Choice	MISO Zone 2, 3 or 5	Applicable to wind only
5th Choice	Resources that don't fall into the Choice 1-4 categories	No additional restrictions

Intermittent		
1st Choice	Inside Company's LBA	No additional restrictions
2nd Choice	Inside of MISO Zone 6, Outside Company's LBA	No additional restrictions
3rd Choice	Inside of MISO Zone 4 or 7	• PPAs only (no asset sale bids will be accepted): • PPA term length must be between 3-5 years
4th Choice	Resources that do not fall into the Choice 1-3 categories	• Resources may be considered on a project-by-project basis: • All 3rd Choice PPA term restrictions apply to this category as well

Transaction Structures and Deal Types

Transaction structures and deal types include PPA with a minimum term length of three years, asset transfers, build-transfers and self-developed.

Evaluation Criteria and Weighing

Evaluation criteria and weighting is based on a 1000-point scale:

- **Economic Value (300 points)**: The economic value on a NPV basis will be calculated over a fixed planning horizon for all assets. The economic analysis will reflect all expected costs related to the bid. The project-level analysis will be based on data submitted with the bids, standard assumptions for key commodity considerations and may reflect adjustments for material uncertainties associated with a bid.

- **Capacity Asset Reliability and Deliverability (300 points)**: The asset reliability and deliverability evaluation will include an assessment of facility age and performance, fuel risk, and fuel security. Facility performance will be based on the equivalent forced outage rate demand performance. Fuel reliability will consider fuel availability risk and price volatility. Due to uncertainty associated with the proposed rules under EPA's Clean Air Act Section 111 (which were not yet finalized at the time of evaluation), scoring of thermal units reflects a preference for newer generation machines under the reliability metric.

- **Development (200 points)**: Development status considered both interconnection and site control related milestones achieved to date for a project that has not reached its COD. In addition, proposals were scored based on the experience of the developers sponsoring the project's development.

- **Asset-Specific Benefits/Risks (200 points)**: This category will consider individual, unique, project-level risks associated with an individual project or counterparty. CRA will evaluate projects based on community benefits, certain social justice goals, minority- and women-owned business considerations, unique environmental considerations, specific regulatory risks or other considerations.

Stakeholder Process

Charles River Associates conducted an RFP stakeholder information session on November 23, 2023. The high-level structure and scope of the RFP was shared with interested parties. Participants that were interested in detailed information were requested to execute a non-disclosure agreement with the Company.

Schedule

Table G-9 below describes the 2023/2024 RFP Schedule.

Table G-9: 2023/2024 RFP Schedule

2023/2024 RFP Schedule	
Task	**Date**
Submitted 2021 IRP to the Commission	12/15/2021
Sent Notification and Meeting Notice for Stakeholder Information Session	10/20/2023
Conducted Stakeholder Information Session	11/3/2023
Distributed Primary RFP Documents to Stakeholders that have Signed NDAs for Stakeholder Feedback	11/6/2023
Stakeholder Feedback Deadline	11/17/2023
Fall 2023 Modeling Update Informed RFP Need	12/13/2023
Issued RFP	12/14/2023
Prequalification Documents Due	1/16/2024
Intermittent Proposals Due	2/23/2024
Non-Intermittent Proposals Due	2/23/2024
Bid Evaluation	March – June 2024
Informs 2024 IRP Modeling Process	April – May 2024
Charles River Associates – Opinion Letter & Ranked Order List	August 2024
Additional Due Diligence and Definitive Agreements Signed with Bidders	Late Q3 – Q4 2024

High-Level Results

The 2023/2024 RFP Request for Proposal high-level results are shown below in Table G-10.

Table G-10: 2023/2024 RFP High-Level Results

Resource Types	Total Projects	Total Net Capacity (ICAP)
Intermittent		
Solar	22	5,145 MW
Solar Paired with Storage	21	4,612 MW
Wind	8	1,777 MW
Non-Intermittent		
Thermal	4	5,105 MW
Standalone storage	13	2,001 MW

Average Cost Data

Charles River Associates provided averaged cost data based on the bid results to Duke Energy Indiana's IRP modeling team, which were used to inform the resource cost and availability assumptions in the IRP modeling. The average pricing across bids is shown in Table G-11 below.

Table G-11: 2023/2024 RFP Average Weighted Pricing by Technology and Deal Structure

Technology	Asset Sale (Balance to Achieve)		Power Purchase Agreement			
	$/kW	Count	$/MWh	$/kW-mo	$/kW-yr	Count
Solar	$2,100	10	$68	–	–	73
Solar Paired with Storage	$3,360	8	$69	–	–	22
Wind	–	–	$66	–	–	15
Thermal	$1,665	8	–	$12	–	5
Storage	$1,931	7	–	–	$158	20

Note: This table reflects proposals received (not projects). Some proposals are mutually exclusive or have been bid as both Asset Sale and PPA.

Plans for Future Requests for Proposals

Duke Energy Indiana fully expects to issue future RFPs to support the procurement of future resources. RFPs may be issued following an IRP filing or periodic modeling update. The bid information solicited in the RFP not only helps identify resources that Duke Energy Indiana may decide to procure, but also informs the market costs for specific resource types to help confirm modeling assumptions. Lastly, the combined RFP, IRP, and modeling information can support CPCN filings with the Commission.

Appendix H: Demand-Side Resources & Customer Programs

Duke Energy Indiana (or the "Company") recognizes the importance of customer programs in managing reliability on the grid. From load flexibility programs to help manage peaks and intermittency of the grid to energy efficiency ("EE") programs designed to reduce peak capacity, Duke Energy Indiana offers its customers a full suite of programs. Due to trends in the electrification of heating and transportation load as well as the increasing penetration of intermittent generation, the Company is innovating on demand-side capabilities that will contribute to continued reliability for customers. The Company is closely monitoring new policies such as Federal Energy Regulatory Commission ("FERC") Order 2222 ("FERC 2222") and the Inflation Reduction Act of 2022 ("IRA") as well as the adoption of smart home assets that can participate in load management and the technology that reliably controls it. The demand-side resources and customer programs discussed herein fall into the following categories and will be described in more detail throughout this Appendix, including a discussion of their contributions to Duke Energy Indiana's 2024 Integrated Resource Plan ("IRP").

Energy Efficiency

Duke Energy Indiana's portfolio of EE programs encourages customers to reduce energy usage, which, in turn, can help these customers reduce their electricity bills. The Company's EE programs, such as the Smart $aver® programs detailed below, offer proven, cost-effective means for reducing energy consumption from the grid.

Demand Response

Demand response ("DR") programs provide bill credits to participants for reducing their demand during times of peak load on the grid or system emergencies, providing an additional resource to ensure system reliability. All customers benefit from the use of this cost-effective resource because it lowers the capacity the Company must build, contract for, or purchase in the Midcontinent Independent System Operator ("MISO") capacity auction, which then lowers customer rates. Duke Energy Indiana offers demand response programs for all customer classes, from residential to small and large commercial and industrial.

Voltage Optimization

Voltage optimization, performed through a function called Integrated Volt-Var Control ("IVVC"), is the coordinated control of substation and power line equipment to manage voltage and power factor on distribution circuits. Duke Energy Indiana operates IVVC in the form of Conservation Voltage Reduction ("CVR"). CVR functionality is expected to run continuously and facilitate energy reduction on a year-round basis. CVR enables sustained voltage reduction, which ultimately reduces the amount of fuel required to meet customer demand. The devices installed to enable this functionality also serve to modernize the grid and support the growth of distributed energy resources ("DER") by improving voltage management to customers and enhancing the grid's ability to manage two-way power flow and respond to dynamic system conditions, such as variability in DER output.

Rate Design

Contemporary industry trends and evolving customer needs call for innovative rate design and program solutions. The Company is currently taking action to make new time of use ("TOU") rates more widely available, updating pricing signals, and reducing other barriers to TOU participation.

Electric Vehicles

A collection of rates, deployed assets, and customer programs will be needed to support the growth in electric transportation in Indiana. Duke Energy Indiana offers tailored products to simplify electric vehicle ("EV") adoption and manage charging for the unique needs of its residential, commercial and industrial customers. These products benefit customers by mitigating costs and allowing Duke Energy Indiana to ensure grid readiness for electrification.

Behind-the-Meter Generation

Behind-the-meter ("BTM") generation generally refers to customer-sited resources, primarily solar and solar paired with storage (approximately 15% of currently installed solar systems are coupled with storage). The Company currently offers the Excess Distributed Generation tariff that specifies the rate at which exports from distributed resources are valued.

Clean Energy Customer Programs

Clean energy programs provide voluntary options for customers to accelerate their own sustainability journey beyond installing renewable generation on their property. Options include ways for both residential and business customers to gain the rights to renewable energy certificates ("RECs"), which can be used to match a desired percentage of their energy use with renewable, carbon-free energy.

Energy Efficiency

Landscape

For over three decades, Duke Energy Indiana has worked constructively with stakeholders to actively pursue and offer customers innovative and cost-effective EE programs. This long-term commitment to EE has been possible in large part due to constructive regulatory models that appropriately align the Company's incentives with customers' interests and promote achievement of energy savings in as cost-effective a manner as possible. These factors, along with Duke Energy Indiana's position that EE programs are a key component of the electric utility service, led the Company to continue its long-standing commitment to offering robust energy efficiency programs.

The EE program management teams have been optimistic that the EE market would return to pre-pandemic levels. With COVID-19 restrictions and safety concerns of recent years lifted, staff was able to fully engage with customers to help them achieve their energy and sustainability goals. As technologies evolve, allowing for more innovative offerings, customers seeking to control their energy usage, lower peak demand, and ultimately save on electric bills require more support from the Company than before the pandemic. Fundamental changes to the market pose new challenges and opportunities for customers to adopt EE programs. The reality is that inflation and interest rates hinder many customers from seriously considering substantial investment in efficiency upgrades. Customers across all segments are facing more urgent challenges given current macroeconomic conditions. These economic challenges, however, may be mitigated through a combination of opportunities of IRA funds, utility program rebates, increased energy consulting, and robust customer engagement, which will be critical to help move past these challenges and spur EE adoption.

Challenges to Expanding the Energy Efficiency Portfolio

Cost of Capital for Investments

Inflation and the associated increased cost of capital has depressed market activity for EE investment. Higher interest rates make new construction and existing homes less affordable today than in previous years. Families and business owners are delaying investments in hopes of lower interest rates and a reduction in inflation in the future. Business customers, in particular, base these decisions on strategic priorities and a near-daily examination of how to allocate resources. Based on program management teams' experience in the market, the business customer focus has shifted away from operational growth and more toward maintaining earnings and boosting efficiency within their current facilities. These decisions have led to a decrease in EE and clean energy investment.

Standards Advancement

Energy efficiency savings can be realized in two ways: through the implementation of standards in equipment and appliances, or through the Company's proposed EE programs. Advancements in EE equipment and appliance standards have generally paved the way for increased energy savings being realized in Duke Energy Indiana's footprint, but they have also impacted the Company's EE portfolio savings because they have increased the marginal cost of new equipment and confused customers regarding both equipment choices and benefits. Families and businesses at all income levels are being challenged by higher prices for most consumer goods and services needed for daily living or to run a sustainable business. Prioritizing energy upgrades and dedicating more resources to energy saving investment is an option that many families and businesses cannot afford to make when the return on investment is not obvious or immediate. The families and businesses that are delaying investments will look to repair existing older equipment when possible. Situations with an emergency or required equipment replacement present an opportunity to choose a high-efficiency option or go with the lesser efficiency standard option, both of which are likely an efficiency gain over the existing equipment. However, cost and a lack of clarity could steer customers to purchase the lesser efficiency standard option when they lack incentives and information to purchase the higher efficiency standard appliance.

One example of the consequences of higher energy standards on the Company's EE offerings pertains to the changes in lighting standards. In the past, Duke Energy Indiana has offered residential lighting EE programs that gave participating customers the ability to make simple and inexpensive updates to their home by using utility incentives to offset the costs. The Energy Independence and Security Act changed lighting standards, which accelerated non-specialty light-emitting diode ("LED") lighting becoming the baseline standard. Residential EE programs that offer general service bulb technologies have consequently seen decreasing energy savings. In short, those changes in lighting standards have essentially eliminated most residential utility lighting programs that previously were key to generating awareness and education for customers trying to determine the right lighting solution for their home.

Workforce & Trade Ally Shortages

Across the Duke Energy Indiana vendor and trade ally networks, staffing, recruitment, and retention have been a great challenge. With gaps in contractor employment, trade allies are not able to commit to projects, and, therefore, customers may be unable to find contractors to install EE equipment. Fewer qualified workers and higher wages have caused a challenge for businesses to maintain expected profit margins and have caused many companies to sacrifice performance until the right workers can be trained. This is especially challenging when contracts for measure installation were executed before inflationary risks were considered. Employee loyalty has diminished as the tight labor market creates higher wages and more upward mobility for skilled workers. Constant turnover causes disruption in the programs and increases costs as management spends more time and resources training new employees. Additionally, some trade allies do not have the administrative support to complete the back-office paperwork and submit claims for EE rebates.

Availability of Eligible Equipment

Residential heating ventilation and air conditioning ("HVAC"), electrical, windows, doors, and heat pump water heaters are all experiencing significant price increases and/or supply chain delays, which stretches project timelines and complicates worker scheduling efficiency. Due to limited availability of high-end commercial equipment, fewer installations have taken place or opportunities for efficiency are missed because standard efficiency equipment is more readily available to customers. For midstream programs, distributors that are unable to stock high-efficiency equipment resort to selling standard efficiency, particularly in cases of emergency replacements. Commercial equipment distributors have reported lead times ranging from 25 to 50 weeks for direct expansion units and 25 weeks for water source heat pump systems.

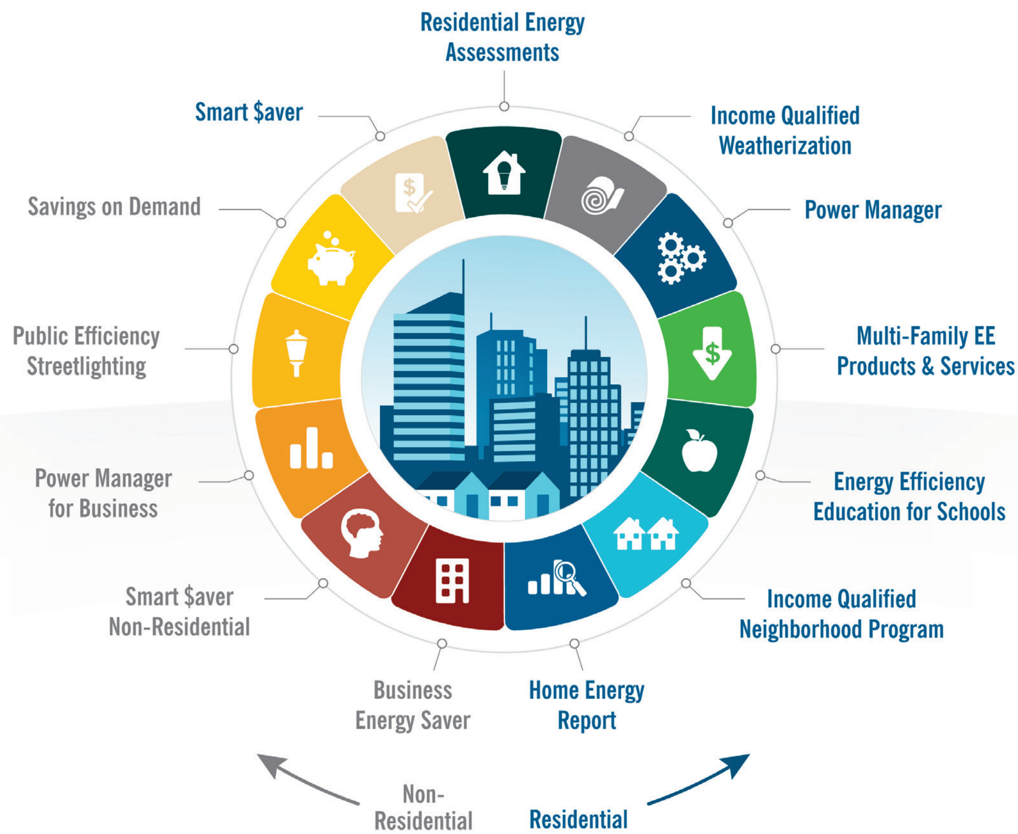
Funding Opportunities & Challenges

The combination of IRA funds and EE utility program incentives will help customers overcome some of the economic barriers, such as inflation and rising interest rates. Duke Energy Indiana is actively reviewing both the IRA and the Infrastructure Investment and Jobs Act ("IIJA") to identify potential funding opportunities to help their customers in this regard. Stacking the incentives from all funding structures will make investing in EE more attractive and understandable for all customers, but the short-term challenge is developing clear, cogent customer guidance on all the IRA and IIJA resources available. Customers themselves may not be knowledgeable about how to access funds or determine the project specifications for which they are eligible. The Company is actively engaging with the pertinent state and federal agencies to define the scope of the opportunities and outline the processes for application, and they intend to provide both digital tools and robust guidance to customers on how to access funds. Customers will benefit from the Company's efforts to coordinate dedicated oversight, program management, and tools that clearly lay out the road map to access the available funding. While Duke Energy Indiana works to develop this road map, the United States Department of Energy ("DOE") and Indiana Office of Energy Development are finalizing eligibility criteria and the process for customers to apply for the incentives.

Contributions to Resource Plan

Duke Energy Indiana has an approved portfolio of energy efficiency and demand response programs that run from 2024-2026, which has been approved by the Indiana Utility Regulatory Commission ("Commission") in Cause No. 45803. These programs, shown in Figure H-1 and described below, are included in the 2024 IRP modeling in all cases. To help inform future EE and DR opportunities within the service territory, Duke Energy Indiana retained Resource Innovations ("RI") to conduct a Market Potential Study ("MPS"). The details of the MPS and how it was used in the 2024 IRP modeling are discussed after the program descriptions below.

Figure H-1: Duke Energy Indiana Energy Efficiency & Demand Response Programs



Residential Energy Efficiency Portfolio

Smart $aver Residential

Duke Energy Indiana's Smart $aver® Residential program is made up of a suite of offerings and incentives on a variety of energy conservation measures designed to increase energy efficiency in new or existing residential dwellings, including HVAC equipment, smart thermostats, insulation and air sealing, water heating, duct sealing, pool pumps, and air quality. The HVAC equipment measures offer customers incentives to help improve the efficiency of the single largest energy user in a typical home. These HVAC measures include a multi-tiered incentive structure, based on the efficiency rating of the new unit installed, along with an optional smart thermostat that customers can choose to combine with the equipment replacement to further improve the efficiency of the HVAC system. Customers can receive incentives for a combination of individual measures within Smart $aver and are provided a referral channel for trusted trade allies which is described below.

Find It Duke Referral Channel

The Find It Duke referral channel program offers a free service to enhance customer awareness and participation in energy efficiency initiatives by connecting them with reliable, qualified contractors. This program supports Duke Energy Indiana's role as an energy efficiency program administrator and fosters partnerships with customers and trade allies, including HVAC contractors, home performance contractors, and home builders. High-performing trade allies can receive referrals, with eligibility based on their engagement and performance in the program. The Company generates leads for these trade allies, who pay a fee for referrals, which is reinvested into the program to improve cost-effectiveness. Customers of both referred and non-referred trade allies continue to receive energy efficiency incentives for eligible measures.

Residential New Construction

The Residential New Construction program offers incentives to builders of new single-family homes and new multi-family properties constructed to higher efficiency standards than existing building codes. Builders may use a combination of construction techniques, equipment, and materials to achieve the higher energy savings.

Online Savings Store

The Duke Energy Online Savings Store is an on-demand ordering platform enabling customers to purchase a variety of energy efficient products for their home, including a wide selection of smart thermostats, smart strips, water savings products, dehumidifiers, air purifiers, lighting and more. Incentive levels vary by product and various promotions are run throughout the year, offering customers reduced prices and free shipping. The Savings Store also provides educational information to help customers with their purchase decisions.

Save Energy & Water Kit

The Save Energy and Water Kit is designed to increase energy efficiency for residential customers by offering water heater pipe insulation wrap and energy efficient water measures to install in high-use fixtures within their homes. These energy-saving devices are shipped directly to customers with an electric water heater, free of charge. Customers receive a kit with either one or two low-flow wide pattern showerheads, as well as two bath aerators, one kitchen aerator, and water heater pipe insulation wrap. Customers can purchase upgraded hand-held showerheads at a discounted price to be included in their kit. The kit also includes directions and items to help with installation.

Home Energy Report

The Home Energy Report ("HER") program provides customers with a comparison of their energy usage to similar single-family and multifamily residences in the same geographical area based upon the age, size, and heating source of the home. Specific energy-saving recommendations are provided to encourage energy-saving behaviors. Beyond monthly reports, the HER web portal provides customers the ability to create a savings plan and see how energy is used in the home by end use (heating, cooling, kitchen, laundry, electronics, and more). The portal also connects customers to an energy expert to respond to questions and delivers weekly email challenges.

The HER program is a foundational part of the existing EE portfolio because it provides customers with an awareness of their usage and delivers insights they can use to reduce their monthly electric bill, including information about EE measures available to them through the Duke Energy Indiana Residential EE Portfolio.

Neighborhood Energy Saver

The Income Qualified Neighborhood program, known as the Neighborhood Energy Saver ("NES") program, assists low-income customers in reducing energy costs through energy education and installation of energy efficient measures. The primary goal of this program is to empower low-income customers to better manage their energy usage. Customers participating in this program will receive a walk-through energy assessment and one-on-one education. Additionally, the customer receives a comprehensive package of energy efficient measures. These measures, shown in Figure H-2 below, are installed or provided based on the opportunities identified in the assessment.

Figure H-2: Measures Offered by the Neighborhood Energy Saver Program

Targeted income-qualified neighborhoods qualify for this program if approximately 50% of the households have incomes of <200% of the Federal Poverty Guidelines. Duke Energy Indiana analyzes electric usage data to prioritize neighborhoods that have the greatest need and highest propensity to participate. While the goal is to serve neighborhoods where the majority of residents are low income, this program is available to all Duke Energy Indiana customers in the defined neighborhood. This program is available to both homeowners and renters occupying single-family, manufactured housing and multi-family dwellings.

The community approach offered by Neighborhood Energy Saver offers the following benefits:

- Community involvement raises awareness of energy efficiency opportunities
- Community leaders provide a trusted voice
- Greater acceptance is possible when neighbors and friends go through this program together
- Efficiencies are gained by working in the same close proximity for longer periods of time
- More resources are available to the individual participants to meet their needs
- Enrolling is simple
- Implementation of measures is fast and easy
- Timely tracking and reporting of activity

Income Qualified Weatherization

The Income Qualified Weatherization program is designed to help low-income customers reduce their energy consumption and lower their energy cost. Available to homeowners and renters meeting DOE standards-based income qualification levels, this program provides direct installation of weatherization and energy efficiency measures including refrigerator and furnace replacement. Duke Energy Indiana utilizes the Indiana Housing and Community Development Authority ("IHCDA") to administer the program in partnership with the Indiana Community Action Association weatherization network.

Energy Efficiency Education in Schools

Duke Energy Indiana is proud to promote conservation and energy efficiency education for grades K-8 in its communities. The Energy Efficiency Education in Schools program is available to students enrolled in public and private schools who reside in households served by Duke Energy Indiana. In partnership with the National Theatre for Children, the Company uses professional actors to teach students about energy efficiency through engaging and informative live theater sketches.

The primary goal of this program is to educate students on the importance of energy conservation and teach them how to translate it into practical applications to lower energy bills in their homes. This program includes both an energy-saving curriculum for the school classroom and an Energy Efficiency Starter Kit at no cost to the student's household.

Multifamily Energy Efficiency Products & Services

The Multifamily Energy Efficiency Products & Services program allows Duke Energy Indiana to use an alternative delivery channel, which targets multifamily rental complexes. Often times, neither property managers/owners or tenants are motivated to make energy efficiency improvements because they either don't pay the electric bill, or the residence is considered temporary. This program bridges this gap by educating property managers/owners about benefits and provides a low-cost/no-cost solution for improving the efficiency of the apartments.

Residential Energy Assessments

Residential Energy Assessments is a free in-home assessment designed to help customers reduce energy usage and energy cost. A Building Performance Institute ("BPI")-certified energy specialist completes a 60-to-90-minute walk-through assessment of the home and analyzes energy usage specific to the home to identify energy-saving opportunities. As part of the assessment, the energy specialist reviews and provides a customized report to the customer that identifies actions the customer can take to increase energy efficiency in their home. The recommendations may range from behavioral changes to equipment modifications that can save energy and reduce cost.

Customers receive an Energy Efficiency Kit with a variety of measures that can be directly installed by the energy specialist at the time of the assessment. Customers can also purchase a smart thermostat for $100 and get free installation at the time of the audit and/or purchase a blower door test as part of the audit.

Non-Residential Existing Energy Efficiency Portfolio

Business Energy Saver

The purpose of Duke Energy Indiana's Business Energy Saver program is to reduce energy usage through the direct installation of energy efficiency measures within qualifying small and medium non-residential customer facilities. The program is designed to offer a convenient, turn-key process for non-residential customers to make facility energy efficiency improvements. Many small and medium business owners lack the time, upfront capital, or technical expertise to facilitate the retrofit or replacement of older equipment within their facilities. Business Energy Saver effectively removes these barriers by offering a turn-key energy efficiency offering, which facilitates the direct installation of energy efficiency measures and minimizes financial obstacles with significant upfront incentives from Duke Energy Indiana, which offset the cost of projects. Participants may be in owner-occupied or tenant facilities with owner permission.

The Business Energy Saver program incentive amount is calculated per project, based upon the estimated energy savings of the energy efficiency improvements and the conditions found within the customer's facility. Incentivized measures address major end uses in lighting, refrigeration, and HVAC applications, as well as processes involving ventilation, water, kitchen equipment, refrigeration, pumps, and building controls. In anticipation of technological advancements, Duke Energy Indiana offers the flexibility to incentivize additional cost-effective measures where appropriate within these applications. To encourage participation within this hard-to-reach customer segment, Duke Energy Indiana provides an upfront customer incentive for up to 80% of the total cost of installed measures. Incentives are provided based on cost-effectiveness modeling to ensure cost effectiveness over the life of the measures. The program also offers interest-free extended payment options to the customer, to further minimize any financial barriers to participation.

Smart $aver Non-Residential Incentive

The Smart $aver® Non-Residential Incentive program provides incentives to commercial, industrial, and institutional consumers for installation of energy efficient equipment in applications involving new construction, retrofit, and replacement of failed equipment. This program also uses incentives to encourage maintenance of existing equipment to reduce energy usage. Incentives are provided based on Duke Energy Indiana's cost-effectiveness modeling to assure cost-effectiveness over the life of the measure. All non-residential customers served by Duke Energy Indiana on a non-residential rate to which the Energy Efficiency Revenue Adjustment is applicable are eligible for the Smart $aver® program, except for those customers that choose to opt out of the program.

This program is delivered to customers through three incentive categories described below: Prescriptive, Custom and Performance.

Smart $aver Prescriptive Incentives

Prescriptive Incentives are predetermined, fixed incentives for common energy efficiency equipment. This program promotes prescriptive incentives for the following technologies: lighting, HVAC, pumps, variable frequency drives, foodservices, process equipment, and information technology equipment. Pre-approval is not required, as equipment and incentives are predefined based on current market assumptions and the Company's engineering analysis. The eligible measures, incentives and requirements for both equipment and customer eligibility are listed in the applications available on Duke Energy Indiana's Business and Large Business websites for each technology type.

Duke Energy Indiana is examining providing a limited quantity of low-cost energy efficient equipment directly to eligible non-residential customers, at no cost to the customer, through this program or in partnership with other Duke Energy programs.

Standards continue to change, and new, more efficient technologies continue to emerge in the market. The Company expects that new measures will be added to the program to increase participation and provide customers a broader suite of products.

Smart $aver Custom Incentives

Unlike Prescriptive Incentives program measures, Custom Incentives require approval prior to the customer's decision to implement the project. Proposed energy efficiency measures may be eligible for Custom Incentives if they clearly reduce electrical consumption and/or demand. Customers applying for Custom Incentives under Duke Energy's Smart $aver® program can choose between the Classic Custom and Custom Calculation Tools approaches, which differ in how energy savings are calculated. Applications include energy savings calculations for various technologies such as variable frequency drives, energy management systems, compressed air systems, and lighting, and customers can opt for application or calculation assistance.

The Smart $aver® Custom Incentives team continues to explore additional program enhancements designed to increase program participation. Recently, the software-based Custom-to-Go calculation tools transitioned to a web-based environment and are marketed as the “Smart $aver® Calculation Tools.”

Smart $aver Performance Incentives

Duke Energy Indiana’s Smart $aver® Performance Incentive provides a mechanism to encourage the installation of high efficiency measures not eligible for Prescriptive or Custom Incentive payments. The Performance Incentive has been designed to complement the Company’s Prescriptive and Custom Incentives and would encourage the implementation of energy conservation measures, which are characterized, at the time of conception, by a degree of uncertainty associated with the result. The types of measures that will be covered by Smart $aver® Performance Incentive will include some combination of unknown building conditions or system constraints, coupled with uncertain operating, occupancy, or production schedules.

To receive payment under this program, customers must apply and get approval before implementing their project. Incentives are based on estimated total project savings and may be paid in installments. An initial payment based on high-confidence savings is made upon project completion and approval, while subsequent Final Measured Incentive Payment(s) are based on verified savings and the applicable incentive rate.

Outdoor Lighting Modernization Program

The Outdoor Lighting Modernization Program promotes the transition to efficient LED lighting for street and area lighting. Existing customers, currently on various tariffed rates, typically use mercury vapor (“MV”), metal halide (“MH”), or high-pressure sodium (“HPS”) fixtures. Upon fixture failure, these are typically replaced with HPS, but customers can opt to upgrade to LED service under Rider 42 or Rate OL-E, with incentives based on wattage.

LED lighting is preferred for its significantly reduced energy use, longer life span, mercury-free composition, and better illumination quality. Rider 42 provides clear rates for LEDs, with no upfront costs unless installations exceed company standards. Customers can choose from standard or decorative fixtures, with clear pricing for poles if needed. Eligible customers are provided with an engineering estimate before accepting the contract. After installation verification, customers receive a per-fixture incentive based on the replaced wattage.

Projected Future Energy Efficiency Impacts

Market Potential Study

Duke Energy Indiana, through its Demand-Side Management ("DSM") Oversight Board ("OSB"), hired a third-party consulting firm, Resource Innovations, to conduct an MPS for EE and DR programs over a 25-year time horizon from January 2025 to December 2049. The full MPS report is included as Attachment H-1. Resource Innovations explored technical, economic, and achievable market program potential. The quantification of these three levels of energy efficiency potential reflects assumptions developed from feedback by the Duke Energy Indiana OSB. The analysis defines these levels of energy efficiency potential according to the Environmental Protection Agency's ("EPA") National Action Plan for Energy Efficiency as illustrated in Figure H-3 below.

Figure H-3: Energy Efficiency Potential

Not Technically Feasible	Technical Potential			
Not Technically Feasible	Not Cost-Effective	Economic Potential		
Not Technically Feasible	Not Cost-Effective	Market Barriers	Achievable Potential	
Not Technically Feasible	Not Cost-Effective	Market Barriers	Budget & Planning Constraints	Program Potential

Source: EPA, Guide to Resource Planning with Energy Efficiency (National Action Plan for Energy Efficiency ("NAPEE"))

Technical potential is the theoretical maximum amount of energy and capacity that could be displaced by efficiency, regardless of cost and other barriers that may prevent the installation or adoption of an energy efficiency measure. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Economic potential is the amount of energy and capacity saved by applying efficiency measures that pass a cost-effectiveness test. The utility cost test ("UCT") is used in this study, in keeping with jurisdictional practice. Achievable potential is the energy and capacity savings that can be achieved in a market with cost-effective, utility-sponsored programs; achievable potential is primarily driven by the influence of incentive levels on customer adoption rates and addresses market barriers associated with customer preferences and opportunity costs. Program potential includes the impacts of reasonable budgeting and planning constraints. RI's analysis assumed Duke Energy Indiana will continue to adaptively manage programs, following the EE/DR program life cycle: market assessment, program design, implementation, evaluation, and adaptation.

The estimated technical and economic potential scenarios as prepared by RI for Duke Energy Indiana are summarized in Table H-1 below, which lists cumulative energy in gigawatt hours ("GWh") and demand savings in megawatts ("MW") for each type of potential. "Cumulative" potential includes savings "roll off" for non-equipment measures or EE retrofits. Savings percentages are presented as a share of year-end sales over 25 years. Technical and economic potential includes savings estimates for all Duke Energy Indiana customers, regardless of program eligibility. Technical and economic potential do not include impacts from the IRA since the IRA funding is irrelevant to technical potential and economic potential is based on the utility cost test.

Table H-1: Cumulative Energy Efficiency Technical & Economic Potential (2025-2049)

Cumulative Potential	Energy (GWh)	% of 2025 Sales	Demand (MW)			
			Spring	Summer	Fall	Winter
Technical Potential	5,878	22%	1,456	1,478	1,350	876
Economic Potential	5,255	20%	1,345	1,367	1,247	752

Tables H-2 and H-3 below summarize the short-term (5-year), medium term (10-year) and long-term (25-year) Duke Energy Indiana EE portfolio achievable market potential energy savings in megawatt-hours ("MWh") for the base, high incentive, and high avoided cost scenarios. Achievable market potential estimates adjust the customer base to remove customers that have opted out of EE and include estimate impacts from the IRA funding; these impacts are presented over each stated time horizon (5 years, 10 years, and 25 years). For additional detail on the MPS, see attachment H-1.

Table H-2: Energy Efficiency Achievable Market Potential – Energy Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Energy (MWh)	244,600	214,301	200,437
High Incentive		277,521	251,706	231,005
High Avoided Cost		254,363	216,096	200,812
Base	Cumulative Incremental Energy (MWh)	820,509	1,577,248	1,703,116
High Incentive		963,366	1,874,902	2,188,708
High Avoided Cost		858,177	1,653,518	1,742,073

Table H-3: Energy Efficiency Achievable Market Potential – Demand Savings

Scenario	Metric	2029	2034	2049
Base	Annual Incremental Spring Peak Demand (MW)	48	42	42
High Incentive		58	50	49
High Avoided Cost		49	42	42
Base	Annual Incremental Summer Peak Demand (MW)	47	41	42
High Incentive		58	50	49
High Avoided Cost		49	42	42
Base	Annual Incremental Fall Peak Demand (MW)	44	38	38
High Incentive		53	46	45
High Avoided Cost		45	39	39
Base	Annual Incremental Winter Peak Demand (MW)	55	44	39
High Incentive		58	51	43
High Avoided Cost		57	44	39
Base	Cumulative Spring Peak Demand (MW)	156	307	347
High Incentive		201	401	476
High Avoided Cost		162	319	353
Base	Cumulative Summer Peak Demand (MW)	155	304	344
High Incentive		201	402	475
High Avoided Cost		159	314	349
Base	Cumulative Fall Peak Demand (MW)	144	283	322
High Incentive		185	369	440
High Avoided Cost		149	293	327
Base	Cumulative Winter Peak Demand (MW)	176	335	326
High Incentive		190	367	401
High Avoided Cost		183	350	335

The Market Potential Study formed the basis of the projected impacts from EE and DR programs to be used in the 2024 IRP. Duke Energy Indiana developed 10 sub-portfolios of EE programs (also referred to as “bundles”). These bundles were designed to be treated similarly to supply-side resource options for selection in the 2024 IRP modeling. The EE bundles were modeled based on the currently approved DSM portfolio and two of the three Duke Energy Indiana MPS scenarios: the Base scenario and the High Incentive Cost scenario. The annual energy savings estimates were provided by either the currently approved portfolio (2025-2026) or the Market Potential Study (2027-2049). This process enabled the EE programs to compete for selection against traditional generating resources to serve projected customer load.

Short-Term Action Plan

Duke Energy Indiana will begin working on a 2027-2029 Portfolio plan in early 2025 to be filed later in 2025. Duke Energy Indiana will continue to work with their OSB to expand and improve upon EE and DSM programs and make them more attractive and available for more customers - both residential and non-residential. Duke Energy Indiana will also continue to coordinate with the Indiana Office of Energy Development to become customers' go-to resource to assist them in accessing their IRA funds and the complementary utility incentives to overcome economic barriers they may face in investing in EE measures.

Demand Response

Landscape

Duke Energy Indiana has successfully offered customers demand response programs for decades. Reliability is at the core of DR programs. With growing demand, modernizing the generation fleet within Duke Energy Indiana and MISO and increasing penetration of renewables, demand response takes on additional importance. The Company plans to grow customer-sited resources as grid resources to meet peak needs, maximize renewable and Duke Energy Indiana-owned generation, and minimize fuel cost volatility. Operating demand response as a cost-effective alternative to generation continues to be at the core of the Company's strategy. The Company lowers its capacity need because of the capability provided by participants, benefiting all customers.

The Company offers programs for all rate classes to participate in demand response. Residential customers can earn bill credits through the Power Manager® program that includes air conditioning switches and thermostat control. Power Manager® for Business is available to customers who can curtail 100 kilowatts ("kW") or less and allow the company to curtail their air conditioning through company-owned switches and thermostats. Large customers can participate in PowerShare or Savings on Demand, the latter of which is a recently launched program with higher incentives for customers who can commit to the three-year contracts. In an effort to increase the commitments large customers can make, it also includes access to technical help in developing a curtailment plan.

Historically, customer-sited resources have been reserved only for use at system peak or in emergencies. Many utilities, including Duke Energy Indiana, are looking to customer-sited resources to provide capacity orchestrated with their own generators' capacity in the future. The term virtual power plant ("VPP") has recently received a lot of media attention. The Company believes it has run a VPP for many years. What is changing now, with utility and customer-sited technology improvements, are the tools available and the use cases. For instance, the Company believes that customer-sited resources can be utilized to avoid or defer distribution investments and is piloting multiple methods in other Duke Energy service territories that it will bring to Indiana when ready.

In addition to a changing technology environment, policy changes may have significant impacts on DR capability. At the federal level, the Company is watching how FERC 2222 is being implemented across the country and participating in forums offered by MISO and the Commission on the topic. The peak reduction capability identified in the 2024 IRP assumes no impact from FERC 2222 until 2030, and even then, the Company assumes a slow ramp. The Company expects that in time for the next IRP update, more will be known about MISO implementation of FERC 2222 and will update the forecast in the future. Within MISO, there are also changes impacting peak capability. MISO's change to the seasonal construct and accreditation methodology will impact demand response. For example, with the new market potential study complete, the Company will be evaluating adding winter residential measures. Additionally, MISO's proposed accreditation changes for load modifying resources, which may include shorter notification periods and more testing, could cause some large customers to withdraw from DR programs.

Evolving generation sources, customer-sited technology, and policy all lead to demand response evolving from a focus on peak shaving to load shaping with multiple devices in the home or business able to meet the needs of a non-coincident peak distribution circuit, injecting energy when needed or charging storage when there is excess solar energy being generated on the grid. The 2024 IRP currently includes Commission-approved programs and an adder for forecasted impacts of FERC 2222, as mentioned above. Duke Energy Indiana, when approved by the Commission, plans to increase its DR programs to customers as they become cost-effective to offer. The Company sees strong potential in customer-owned batteries for helping to control peaks. Management of electric vehicle charging is addressed later in this Appendix.

Contributions to Resource Plan

Duke Energy Indiana's DR resources are reserved for peak loads in the 2024 IRP modeling. DR programs are not currently selectable resources because of the limited number of hours they can be activated per program rules and the attrition that is seen in some programs when they are activated. As new programs are introduced, the Company will evaluate whether those programs should be handled in a similar method. Despite being modeled differently from centralized generation, DR programs provide a capacity backstop every day and are an important resource for the Company. The Company's current DR program offerings included in the forecasted DR contributions in the 2024 IRP are described below.

Power Manager

Power Manager® is a residential load control program designed to reduce electricity demand by managing air conditioners, electric water heaters, and thermostats during peak periods. A load control switch is installed on the outdoor air conditioning unit or near the water heater of participating customers, allowing Duke Energy Indiana to cycle these appliances off and on during peak high demand times.

The program offers different participation options based on customer preferences, each achieving varying levels of load reduction. Customers receive an initial enrollment incentive and monthly bill credits during the control season or on an annual basis for Power Manager® participation.

Bring Your Own Thermostat

Bring Your Own Thermostat ("BYOT") is a residential DR program leveraging customers' smart two-way communicating thermostats instead of traditional load control switches that are installed by the utility. It is intended for customers who have already purchased, installed, and registered a smart thermostat in their home, allowing the utility to avoid the hardware and installation costs associated with traditional direct load control programs. The utility can verify how many thermostats are operable and online at any given time and determine which thermostats are participating in DR events as opposed to opting out. Duke Energy Indiana has partnered with a third-party vendor who has contracts with multiple thermostat manufacturers to offer demand response through aggregation of the different thermostat models. After successfully enrolling, participants will receive a one-time $75 incentive. In addition, participants will receive a $25 incentive each year following the anniversary of their enrollment in the program.

Power Manager for Business

Power Manager® for Business is a non-residential program that provides business customers with the opportunity to participate in demand response, earn incentives and realize optional energy efficiency benefits. This program is designed as a flexible offer that provides small-to-medium size business customers with options on device types as well as level of demand response participation. Customers first select the type of device from two available options, thermostat or switch, which are installed at no cost to the customer.

Customers who opt for the thermostat will have the ability to manage their thermostat remotely via computer, tablet or smartphone. The thermostat comes with presets designed to help the business manager/owner set an efficient schedule that works for their business. This realizes additional benefits in the form of EE impacts/savings. Customers then select one of three levels of summer demand response participation and earn both upfront and ongoing annual incentives based upon that selection. Both thermostat and switch customers have the same participation options and receive the same levels of incentives.

Savings On Demand

The Savings on Demand program responds to a need in the market to add additional megawatts of capacity by aggressively and actively supporting customers' pursuit of load reduction. Non-residential customers will be presented with a suite of options to enhance demand response curtailment. These include two emergency options referred to as standard and advantage, in addition to an enhanced demand flexibility add on for energy-based curtailment credits.

Customers committing to a three-year contract receive technical assistance for curtailment planning and real-time load monitoring. In the past, customers expressed feedback that their curtailment commitments were conservative, partly due to concerns about penalties and the absence of real-time visibility. Improving customer confidence in their curtailment ability benefits the customer through larger incentives and helps Duke Energy Indiana to lower its capacity need.

PowerShare

The PowerShare® program is offered under Duke Energy Indiana's Standard Contract Rider No. 23 entitled "Peak Load Management." The program provides financial incentives in the form of bill credits to Duke Energy Indiana industrial and commercial customers to reduce their electric demand during the Company's peak load and/or high marginal price periods. Customers may choose to participate in either CallOption or QuoteOption. CallOption requires customers to commit to a pre-selected load reduction, based on historic or usual demand, at a selected strike price. In return for this commitment to reduce load when called upon by the Company, CallOption customers receive a monthly premium payment from Duke Energy Indiana as a credit to their bill. In addition, when customers are called to reduce load, they receive an energy credit. Duke Energy Indiana may exercise its CallOption products based on economic and/or reliability concerns. For economic-related events, when the next day's market prices are projected to be greater than the strike price, Duke Energy Indiana can call the option by notifying customers by 3:30 p.m. ET the day ahead of the event. For reliability purposes, Duke Energy Indiana can call the option by notifying customers at least two hours ahead of an event. Reliability events would typically be initiated in response to a request by MISO.

The Company offers multiple participation options for the CallOption program with different terms and incentive opportunities. The level of incentive received by the customer depends upon customer-selected parameters including the contracted for option load, the strike price, the selected duration (number of hours), and the maximum number of calls. Each option has built-in limitations on how frequently economic events can be invoked during the applicable term and CallOption is available year-round, in accordance with the Commission's Order in Cause No. 44035.

Demand Response Capabilities in Resource Plan

The 2024 IRP includes programs that are approved by the Commission, at budgets approved by the Commission. To the extent it is cost-effective, the Company intends to grow its demand response capability through both existing programs and new ones. The current and future demand response capabilities reflected in the 2024 IRP are shown in Figure H-4 and Table H-4.

Figure H-4: Current DR Peak Load Capability Identified in Resource Plan by Rate Class

Rate Class	Large Customer	Small & Medium Business	Residential
Summer Capability as of 3/31/24	326 MW	5 MW	101 MW

Table H-4: Future DR Peak Load Capability Identified in Resource Plan by Program

Demand Response Peak Load Capability (MW)				
Year	Power Manager[1]	Power Manager for Business	PowerShare	Savings On Demand
Jul-25	53	4	4	234
Jul-26	56	5	4	246
Jul-27	58	6	4	246
Jul-28	59	6	4	246
Jul-29	61	6	4	246
Jul-30	63	6	4	246

Note 1: Power Manager includes DR MW for air conditioner load control devices, water heater load control devices, and customer-owned thermostats (BYOT).

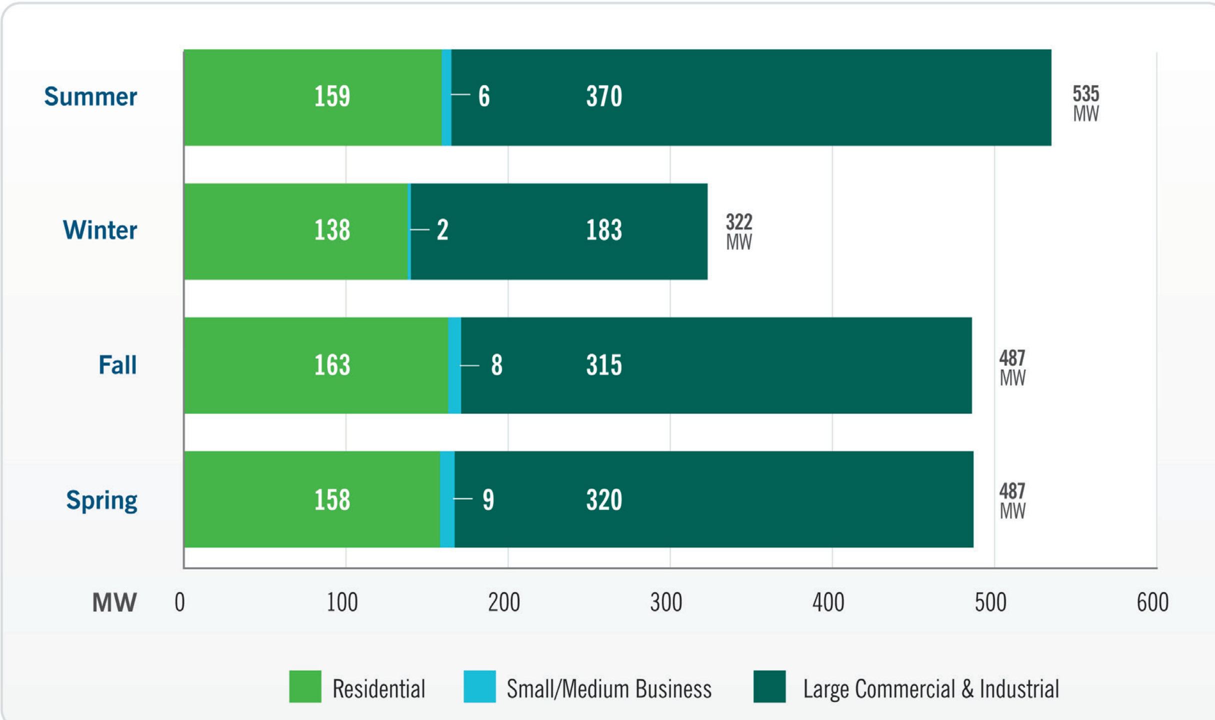
Projected Future Demand Response Impacts

Market Potential Study

In addition to EE potential, the Market Potential Study analyzed DR opportunities for Duke Energy Indiana service territories to determine the amount of seasonal peak capacity that could be reduced through DR initiatives from a technical, economic, and achievable potential perspective. While technical and economic potential are theoretical upper limits, participation rates applied to achievable potential are calculated as a function of the incentives offered to each customer group for utility-enabled DR. For a given incentive level and participation rate, the cost-effectiveness of each DR measure is evaluated to determine whether the aggregate DR potential from that measure should be included in the achievable potential.

Figure H-5 below shows the achievable seasonal peak DR potential estimated for Duke Energy Indiana. These results represent incremental DR potential beyond current Duke Energy program enrollments. The Company will use this information to evaluate additional cost-effective opportunities to develop DR capabilities and customer programs, which may be incorporated in future IRP analyses.

Figure H-5: DR Peak Capacity Achievable Potential by 2049



Enablers

Incentives are the most important factor in a customer's decision to participate in demand response offerings. The Company considers capacity auctions, other utility incentives, and the Market Potential Study prepared for the 2024 IRP in setting compensation levels for participation.

Customers must be aware that programs exist. With an ever-increasing quantity of media channels vying for residential customer attention, this can be difficult. Duke Energy Indiana large account managers and business energy advisors for small and medium business help to keep those customers informed, though the demand response decision-maker may not be their primary contact, adding a layer of challenge to communication.

Increasing adoption levels of smart thermostats will likely lead to more demand response capability from those devices. Other grid-connected customer-sited technologies are also being considered for DR programs, knowing that incentives can drive adoption of those products. Batteries represent a significant potential growth opportunity, depending on the rate at which customers purchase them and allow utility control.

The Company aspires to operate a muti-season, multi-DER, manufacturer-agnostic VPP to be used for peak and normal load conditions. The technology to control this level of complexity is still nascent. With its size, Duke Energy is an attractive client to many software vendors and spends significant time understanding what is available in the market. Reliability of performance is critical to displacement of centralized resources. While it is clear that devices such as batteries, switches and thermostats can be controlled reliably, understanding customer program enrollment rates and solidifying control strategies that provide grid benefit with little customer inconvenience can take time.

Challenges to Expanding Demand Response Capability

Currently, multiple active policy initiatives have the potential to both grow and challenge the growth of demand response. For example, MISO is considering reductions in notification timelines for qualifying load modifying resources, which, if adopted, Duke Energy Indiana believes could significantly reduce large customer participation. Accreditation of resources is also a topic the Company is tracking as it appears that MISO may be considering lower values for load modifying resources, which impacts Duke Energy Indiana's capacity need and affordability for all customers. While not currently known, FERC 2222 implementation rules could have an adverse impact on capability if they are too onerous or confusing. IRA grants are expected to enhance home efficiency, a positive outcome for all. However, as homes become more efficient, their potential for peak capability reduction decreases because a more efficient home has less load to curtail.

Introducing more programs to reduce peak demand and provide load flexibility during other times is positive for the grid, but the interplay with traditional demand response programs is still being studied. TOU rates, voltage optimization and expanding energy efficiency are all intended to reduce peak. As the peak is flattened, there is less opportunity to reduce it. When reviewing demand response capability, it is important to simultaneously consider the growth or reduction in peak. More broadly, the interplay between load modifying programs and demand response is not yet well understood. Time varying rates and voltage optimization are examples of this, as they are likely to be used at the same peak times. If a battery control program is offered in Indiana, for example, the Company will need to consider whether those customers can also participate in other DR programs. Demand response customer programs and grid use cases will continue to grow, but the per home reduction may not, with the exception of those participating in battery programs in which whole home load may be curtailed.

An additional challenge includes macroeconomic cycles, which impact demand response in that large customer loads are higher in strong economies (meaning more peak reduction capability) and lower in weaker economies (meaning less capability).

Duke Energy Indiana is also increasingly reliant on third-party equipment manufacturers in its residential DR programs. Thermostat control, proven popular with customers, is dependent on the manufacturer participating in utility programs. Battery and Electric Vehicle managed charging programs that send signals to control the vehicle's charging will be similar. The Company is closely watching the pricing requested by those manufacturers for the capability to ensure it remains cost-effective as a resource.

As stated above, the Company strives to create a VPP to meet the changing needs of the grid. The Company is optimistic about using customer-sited resources but is also aware of the complexity. The residential loads available to be curtailed today are weather sensitive, and some of the retiring generators across MISO are baseload. Matching curtailable loads to grid conditions when they are available, and the Company's growing load forecast are key drivers for development of the VPP. It is also important to note that PowerShare and Savings on Demand, the Company's large customer DR programs, do have economic options. However, customer utilization is low, so these programs are not yet included in thinking about how customer resources will meet increasing load needs.

Voltage Optimization

Landscape

Voltage Optimization, performed through IVVC, is the coordinated control of substation and power line equipment to manage voltage and power factor on distribution circuits. In Duke Energy Indiana, IVVC is operated in the form of CVR functionality, which is expected to run continuously and facilitate energy reduction on a year-round basis through sustained voltage reduction, which ultimately reduces the amount of fuel required to meet customer demand. The devices installed to enable voltage optimization also help to modernize the grid and improve voltage management to customers, while supporting the growth of DERs such as solar.

Beyond its ability to directly reduce generation needs, the grid will be enhanced to manage two-way power flow. Two-way power flow on a circuit can occur when solar and other DERs generate more power than is needed on the distribution circuit. Implementation of the IVVC program will help transition the grid to manage power flow as DER penetration increases.

Voltage optimization capabilities lead to:

1. Less peak load on the grid, which could result in a reduced need to build additional peaking generation assets.
2. Optimized control of Volt-VAR devices, improving the grid's ability to respond to dynamic system conditions, such as DER (solar) intermittency, while delivering reduced distribution line losses.

Contributions to Resource Plan

A voltage reduction of 2% driven by CVR technology roughly equates to a 1.4% reduction in load for CVR-enabled circuits. The load reduction from IVVC could be handled comparably to demand response mechanisms that focus on reducing customer energy consumption during periods of heightened grid demand. In 2023, Duke Energy Indiana received approval from MISO to register IVVC as a Load Modifying Resource ("LMR"). The implementation of IVVC as an LMR is advantageous for customers and the Company, as it reduces the amount of capacity that the Company would otherwise need to procure to satisfy MISO requirements. In the 2024 IRP modeling, IVVC is included as a supply-side resource that reduces system load.

Enablers

To implement IVVC across the Duke Energy Indiana footprint in a manner consistent with the approaches further detailed in the execution plan section below, regulatory approvals have been and will be required throughout the implementation process to enable the voltage optimization efforts. The following list summarizes ongoing and future regulatory activities to support and enable voltage optimization efforts in Duke Energy Indiana:

- IVVC Phase I – Regulatory approval was received with TDSIC 1.0, completed in 2022
- IVVC Phase II – Regulatory approval was received with TDSIC 2.0, and this project is in-flight

Short-Term Action Plan

The Company is systematically deploying assets to help support current and future voltage optimization. In Duke Energy Indiana, IVVC is currently designed to dynamically support CVR operational mode. CVR is implemented by software within a centralized Distribution Management System ("DMS"). The Duke Energy Indiana CVR plan targets an estimated 2% voltage reduction. Through initial deployments, the Company determined that this voltage reduction target is achieved when operating the system at an average CVR factor of 0.7.

To implement IVVC across the Duke Energy Indiana footprint, the Company is deploying the needed devices in two phases. The Phase I scope accounted for approximately 43% of the total circuits across the footprint. This will enable voltage reduction capabilities for approximately 56% of current baseload. The current plans in-flight for Phase II include equipping another 10% of circuits to enable voltage reduction capabilities for an additional 13% of current baseload. Table H-5 below highlights the percentage of all Duke Energy Indiana circuits equipped with IVVC capabilities compared to the percent of IVVC eligible circuits and the approximate percent of total baseload that the IVVC function will affect.

Table H-5: Duke Energy Indiana IVVC Deployment Phases

IVVC Deployment Phases	% of All Circuits	% of Eligible Circuits	Approx. % of Total Baseload
Phase I	43%	65%	56%
Phase II	10%	15%	13%
Total	**53%**	**76%**	**69%**

The Company is currently working to expand the capabilities of the existing DMS beyond CVR to support peak shaving. To maximize operational flexibility and value, the future DMS can support additional operating modes, such as peak shaving capability and emergency modes of operation. Enhancements to the DMS and field devices will provide flexibility for both capacity and energy-saving capabilities while preserving options for efficient management of the grid.

Rate Design

Landscape

Indiana, like many other states, is facing several broad energy trends that require rate design and pricing to adapt and evolve. Notable trends include the growth of technologies with unique or controllable load characteristics (e.g., EVs), increased customer interest in customer-sited resources (e.g., solar arrays, batteries), and increased interest from the technology industry (e.g., data centers).

Notable Tariff Changes

Duke Energy Indiana is proposing widely available TOU tariffs for residential, commercial and industrial customers to encourage customers to shift energy usage to off-peak hours. The Company is also seeking to close aging rate designs like Low Load Factor ("LLF") Secondary Service that aren't well-structured for today's new challenges and aren't sending optimal price signals to customers. Further, Duke Energy Indiana is seeking to enhance risk-mitigating measures related to large new customer loads such as data centers. To prepare for increasing EV adoption, the Company has proposed a Make-Ready Credit for EV charging with the Commission. The Make-Ready Credit program is discussed further in the Electric Vehicles section of this Appendix.

Resource Plan Coordination

Duke Energy Indiana's new TOU rate structure was informed by the 2024 IRP's load forecast to align peak demand hours to the hours of higher cost.

Figure H-6: Proposed Time of Use Periods

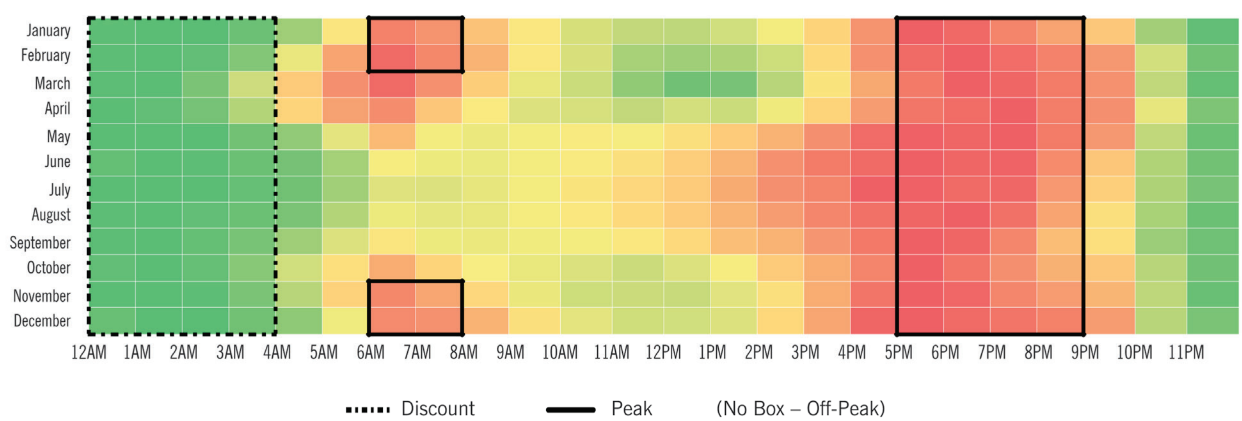


Figure H-6 above depicts demand periods shaded by color: low demand hours are shaded green, and as usage increases, the colors fade to yellow, orange, and then red for the highest demand hours. The Company has proposed TOU rates with on-peak periods of a shorter duration and a consistent evening period running from 5 p.m. to 9 p.m. to complement the traditional morning winter peak periods, which run from 6 a.m. to 8 a.m. The on-peak periods are outlined in the solid black boxes.

The TOU rate structure also includes a proposed “discount” period from 12 a.m. to 4 a.m., which sends more refined price signals and provides an opportunity for new technologies like EVs and batteries to charge during lower cost times. The “discount” period is indicated by the dashed black box.

Enablers

The Company’s ability to implement new rate design constructs like the new proposed TOU rates will be guided by customer interest, stakeholder support and Commission approval. Technological evolution and maturation of existing technologies like batteries, solar arrays and electric vehicles will influence the Company’s future rate proposals. As discussed further in Appendix B (Duke Energy Indiana System Today), Advanced Metering Infrastructure (“AMI”) continues to be a foundational enabler for TOU rates, delivering detailed, near real-time energy usage data. Insights from AMI data further support the Company’s newly proposed TOU rates.

Short-Term Action Plan

Rate design programs such as Green Source Advantage (non-residential), Make-Ready Credit (residential), new TOU rates (residential, commercial and industrial), closing the existing LLF secondary service rate to new participants and replacing it with an improved design, and enhanced new large load financial risk mitigation measures have all been proposed in formal filings before the Commission. Green Source Advantage, which was recently approved, and Make-Ready Credit are described later in this Appendix.

Electric Vehicles

Landscape

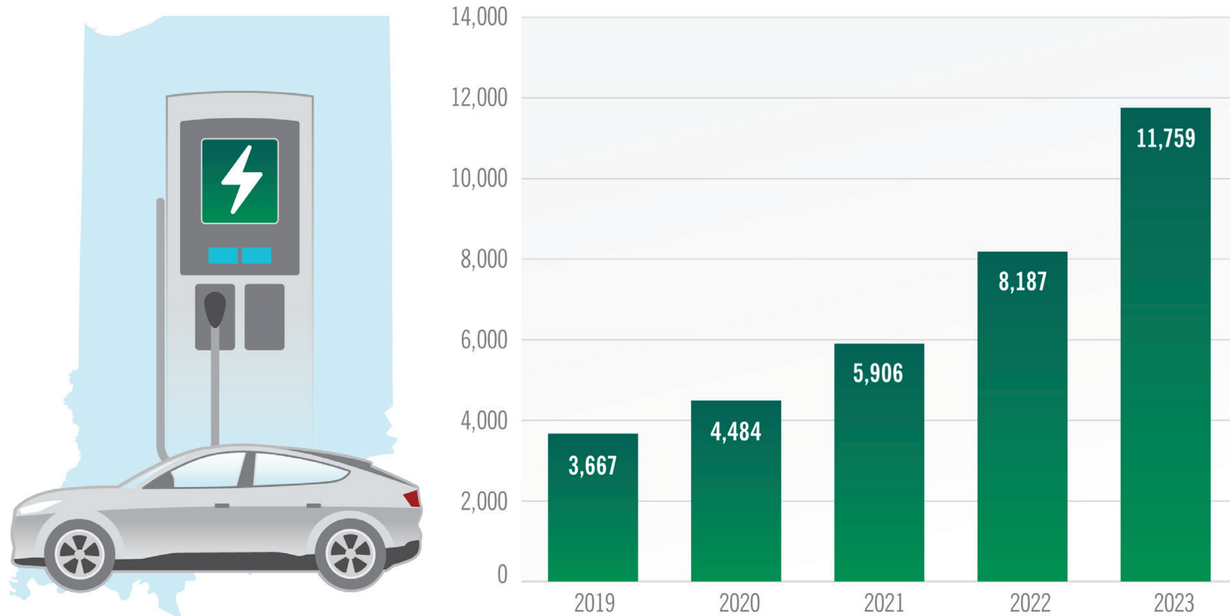
EVs present a set of challenges and opportunities for the utility sector that is both complex and, in some ways, unprecedented. While customers are just beginning to adopt EVs at any scale, federal funding and state policy are increasingly calling for electrified transportation. The Company is and will continue to support the state and its customers as they make the decision to transition to EVs. Programs that simplify adoption and processes that enable the proliferation of EV chargers that will be brought about by state and federal programs will be indispensable.

The load that EVs will add to the system comes with the opportunity to design offers that shape EV charging behavior to increase the cost-effectiveness of the system and to inform effective system planning. To that end, utilities also have an obligation to serve, and the Company is developing programs and new approaches to ensure the grid is ready for electric transportation. Electrification will create unique challenges, especially where localized electric commercial fleet clusters emerge. Moreover, with adoption expected to sharply increase in the coming years, Indiana has an opportunity now to adopt programs that engage the EV-driving community while maintaining the flexibility to adjust as the adoption of a relatively nascent technology occurs at scale.

Historical Adoption Trends

Electric transportation is growing in Indiana. Adoption has increased at least 20% year-on-year since 2019, leading to nearly 12,000 EVs on the road in the Company's footprint as of the end of 2023. Most recently, from 2022 to 2023, EV registrations grew 44%. Figure H-7 below shows the number of EVs registered in Duke Energy Indiana from 2019 to 2023.

Figure H-7: Electric Vehicles in Operation in Duke Energy Indiana



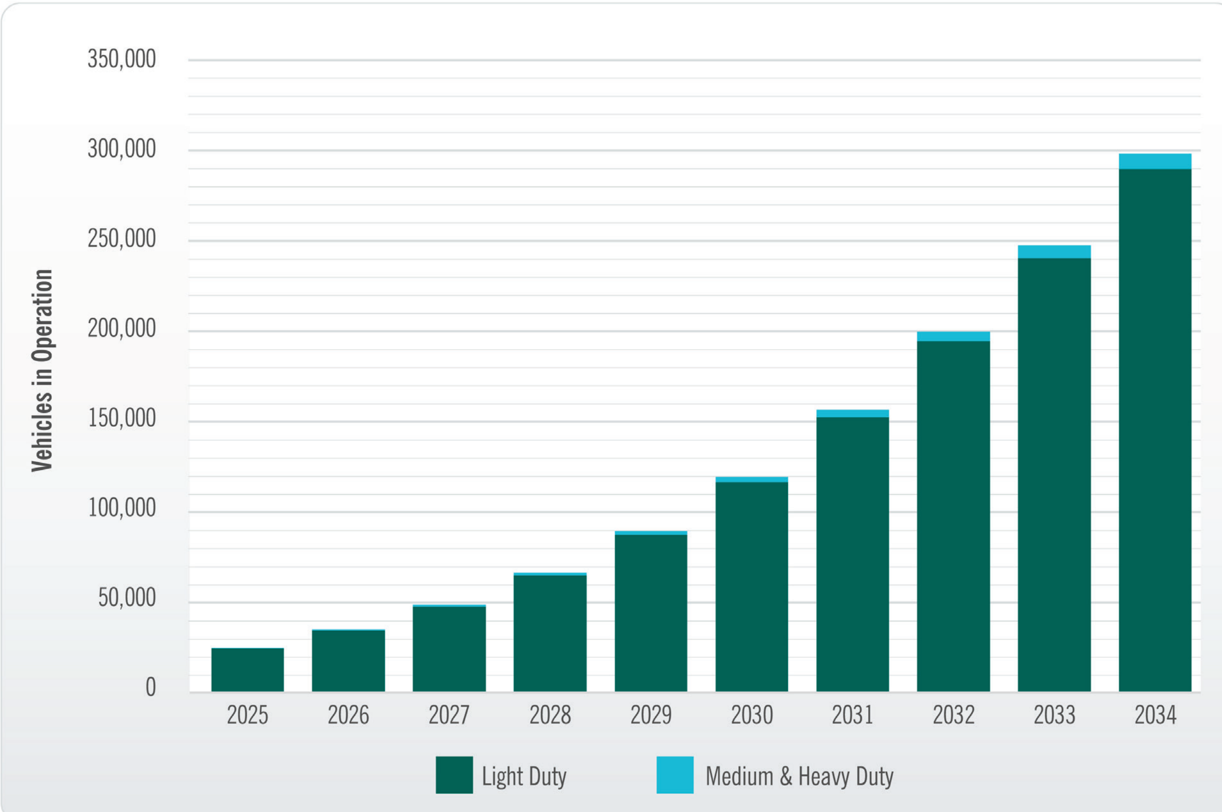
Contributions to Resource Plan

Analysis of Electric Vehicle Adoption & Load Projections

Unsurprisingly, the pace of EV adoption in Indiana is only expected to increase. This is driven not only by growing customer interest in EVs, but also the impact of federal funding and incentives, fleet commitments to and investments in electrification and enabling utility programs.

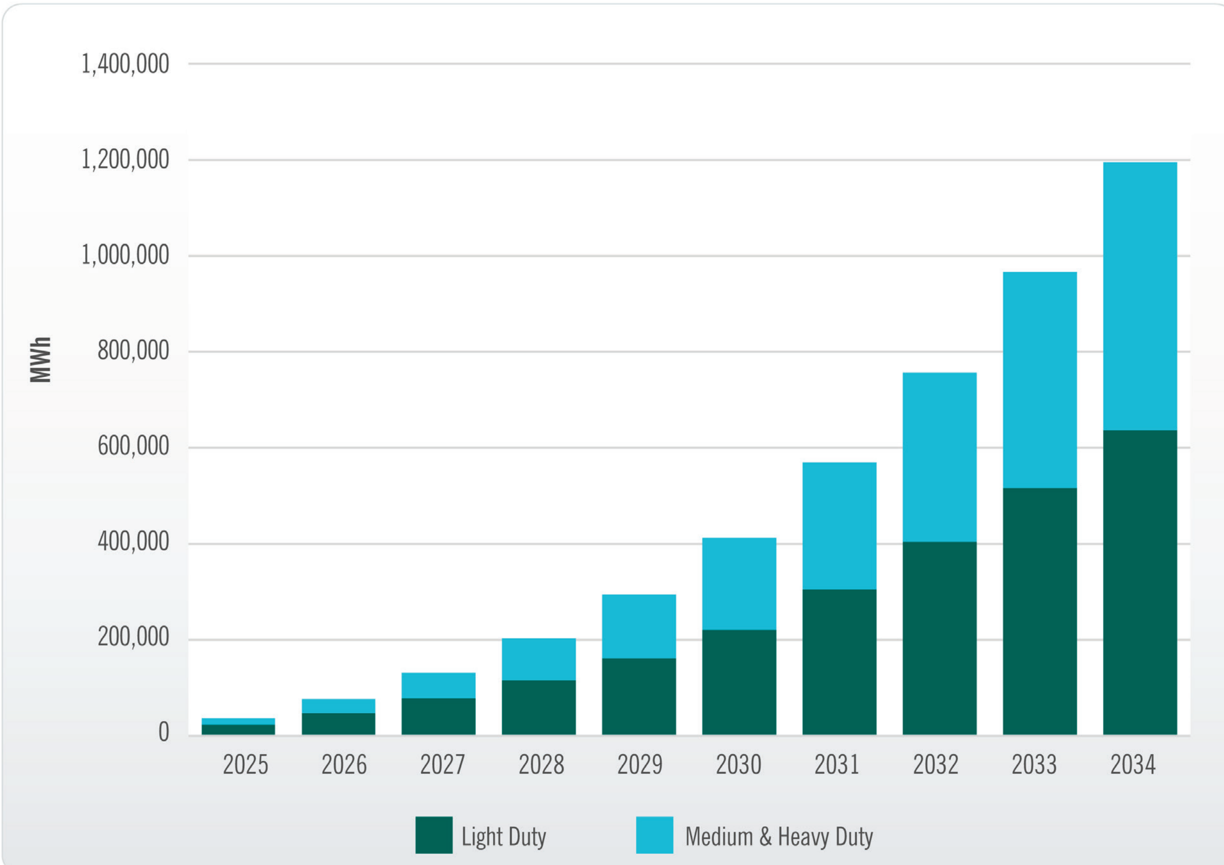
The Spring 2024 EV Forecast from Guidehouse's Vehicle Analytics & Simulation Tool ("VAST") shows that nearly 300,000 EVs are expected on the road in the Duke Energy Indiana jurisdiction by 2034. For this analysis, the Company further breaks down vehicles in operation by light duty as compared to medium and heavy duty. As shown in Figure H-8 below, light duty vehicles consistently dominate adoption forecasts, comprising more than 97% of EVs in operation.

Figure H-8: Forecasted Electric Vehicles in Operation in Duke Energy Indiana



Increased adoption naturally results in increased load projections from EVs. The breakdown between vehicle classes becomes meaningful because while the overall percentage of heavier duty vehicles is low, the load from these vehicles is significant. Generally, medium- and heavy-duty vehicles point to the presence of fleets. And while consumer EV charging might be well-managed with simple programs, fleet EV loads could create localized load clusters that, even if managed, will also present challenges with the Company's provision of electric service. Figure H-9 below shows the forecasted EV load by vehicle class. The methodology to develop the EV forecast and its impact on the 2024 IRP's load forecast is detailed in Appendix D (Load Forecast).

Figure H-9: Forecasted Electric Vehicle Load by Vehicle Class in Duke Energy Indiana



Enablers

This growth in EV adoption necessitates that the Company is engaged with customers as they electrify. In such a developing market that represents unfamiliar territory to most customers, they seek a trusted resource to act as a guide and to solve problems. Adoption-simplifying programs can serve to create connectivity between the Company and EV adopters, helping to ensure that customers are not left to electrify without any participation from their electric utility.

The growth in load likewise warrants that the Company develop capabilities to manage EV charging loads. Effectively managing charging can defer future system investments where possible and harness the potential for EV charging load to put downward pressure on rates by spreading fixed utility costs over more kilowatt-hour ("kWh") sales. A future suite of managed charging approaches and rate design structures, such as the newly proposed TOU designs addressed immediately below, will help the Company to realize the downward rate pressure opportunity associated with EVs.

Consumer Electric Vehicle Load Management

For consumer-owned, light duty vehicles, there are multiple core methods to achieve managed charging. Noting that certain levels of adoption are necessary to make any form of program cost-effective, program options with lower complexity are sufficient at lower levels of adoption, but more sophistication is likely needed as adoption ramps up.

Off-Peak Credit

Perhaps the simplest of managed charging avenues, as described previously, off-peak credit type programs simply ask EV drivers to avoid charging in certain time windows. Likely because of this simplicity, such programs are quite effective, both in recruitment and in shifting load. As discussed below under Current Two-Year Programs, the Company's limited program in Indiana has demonstrated this effectiveness.

Time of Use Rates

TOU rates are an evolutionary step for EV managed charging. Typically, TOU rates have slightly more sophisticated pricing signals than off-peak programs but still manage around system peaks. Importantly, the TOU rate recently proposed by the Company in its pending rate case is meant to be technology agnostic, but still manages EV loads and allows EV customers to save money by charging when the Company has the lowest cost of providing service.

Active Managed Charging

Active charging management represents the most sophisticated means of managed charging. In such an approach, the Company would actively control charging based on system conditions while balancing grid and customer needs (for adequately charged batteries). In practice, this approach - still under development with energy orchestration - is envisioned to work like DR programs, but with the added feature that the Company is turning charging "on" as much as turning it off to achieve the necessary balance of grid and customer needs.

Efficiently Serving Electric Fleet Load

While long-standing rate structures already provide a motivation for commercial operators of electric fleets to leverage times of system availability to charge their vehicles, fleet electrification is not without challenges. Today, fleet operating companies face political and customer – and therefore economic – pressure to decarbonize. As electrification of fleets grows, so does the need for substation and feeder capacity. This gives way to a growing risk for customers and utility operators alike. Most fleets operate medium and heavy-duty vehicles, which consume significantly more energy than light duty vehicles while requiring near perfect reliability to avoid operational disruptions and profit loss. Moreover, fleets are generally located near to one another in warehousing districts and around access to air transport, leading to an inherent localized load clustering effect. The associated risks, however, can be mitigated through strategic planning, funding and early execution. Put simply, a proactive approach.

Many businesses are exploring the electrification opportunity at the same time, and it is probable that many fleets will electrify in the next five years. This may lead to circuits requiring upgrades to satisfy dozens of MW.

Fortunately, not all circuits have significant fleet loads. Many circuits have capacity available for retail and residential requests and/or can achieve upgrades for limited fleet electrification requests in time without delaying fleet customers' goals. The Company’s transportation electrification and system planning experts are surveying the Indiana operating region to determine where opportunities may emerge to serve fleet clusters and therefore meet fleet operators' goals.

The Company’s approach identifies areas in which fleets operate now and determines if those have public electrification goals or significant potential economic benefit through electrification. The most likely candidates are Class 8 and Class 6 operators with shorter and consistent daily routes that include loading periods commensurate with recharging. Logistics fleets serving more localized mail and package delivery or business-to-business delivery are also ripe for electrification in the next two to five years given that vans and medium duty box trucks are becoming increasingly available and can be charged in off-shift (not to mention electric system off-peak) hours.

To convert the presence of fleets to probable, localized electric load growth, the Company’s approach assigns this probability of electrification to sites and couples that data with anticipated charging loads per vehicle. Using those for any given cluster area, blended adoption estimates can be established inclusive of grid impact. Next, clusters are targeted due to their potential to outpace capacity to serve if adoption rates accelerate as anticipated.

The Company plans to continually refine this approach while also building electric fleet analytical tools that integrate well with the time-tested system planning approaches already in use. Today, an opportunity may well exist for Indiana to continue economic growth by considering approaches to system upgrades that reduce barriers to fleet electrification.

Current Electric Vehicle Programs

The Company has deployed programs and continues efforts to support customers as they pursue EV adoption. This support reflects not only the direct link between the provision of electric service and EV charging, but also the Company’s goals to enable customers that choose EVs and to ready the grid. Today, in alignment with the activities that are supported by federal funding, these efforts include foundational infrastructure deployments in conjunction with the state and offering programs and rates that inform, simplify, and increase adoption as well as begin the process of managing EV charging loads at scale.

Park & Plug

The Company has installed 34 direct current (“DC”) fast chargers at 17 locations across Indiana (34 total DC fast chargers). These chargers serve to provide a foundational level of EV infrastructure to support EV adoption. Site hosts include retailers, small businesses, and municipal locations across the state. The program, which the Company refers to as Park & Plug, is a part of a larger statewide network partially funded by the Indiana Volkswagen Beneficiary Mitigation Trust ("VW mitigation funding") to install 61 new EV charging locations. Other major electric utilities involved include AES Indiana, Indiana Michigan Power ("AEP"), CenterPoint Energy, Northern Indiana Public Service Company ("NIPSCO"), Wabash Valley Power Alliance, Hoosier Energy, and Crawfordsville Power & Light.

Figure H-10 below provides a view of the increasing charging sessions across the 17 sites since the first site was brought online in August of 2023. Unsurprisingly, with increasing charging sessions, the amount of energy (in kWh) dispensed by the network of chargers is also increasing, as shown in Figure H-11 below. In total, through the first ten months of operation, the network provided over 144 MWh to travelers in the Hoosier state. Assuming 3.5 miles driven per kWh, this network has enabled more than a half million miles of travel in Indiana.

Figure H-10: Park & Plug Program Charging Sessions Trend

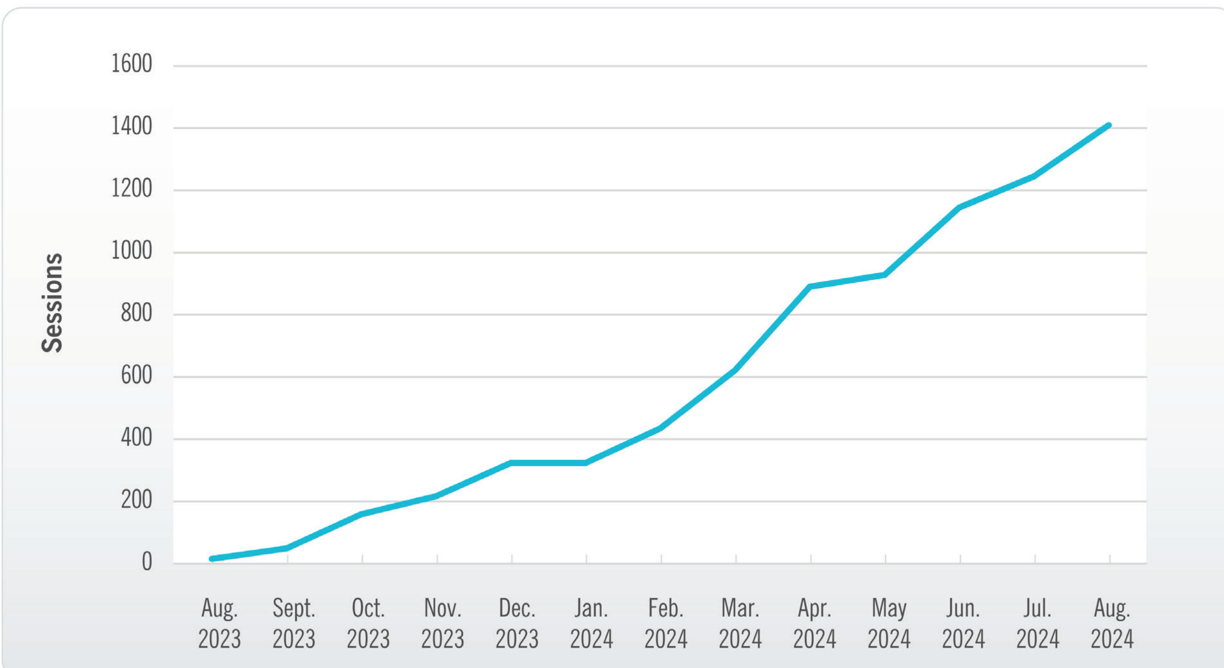
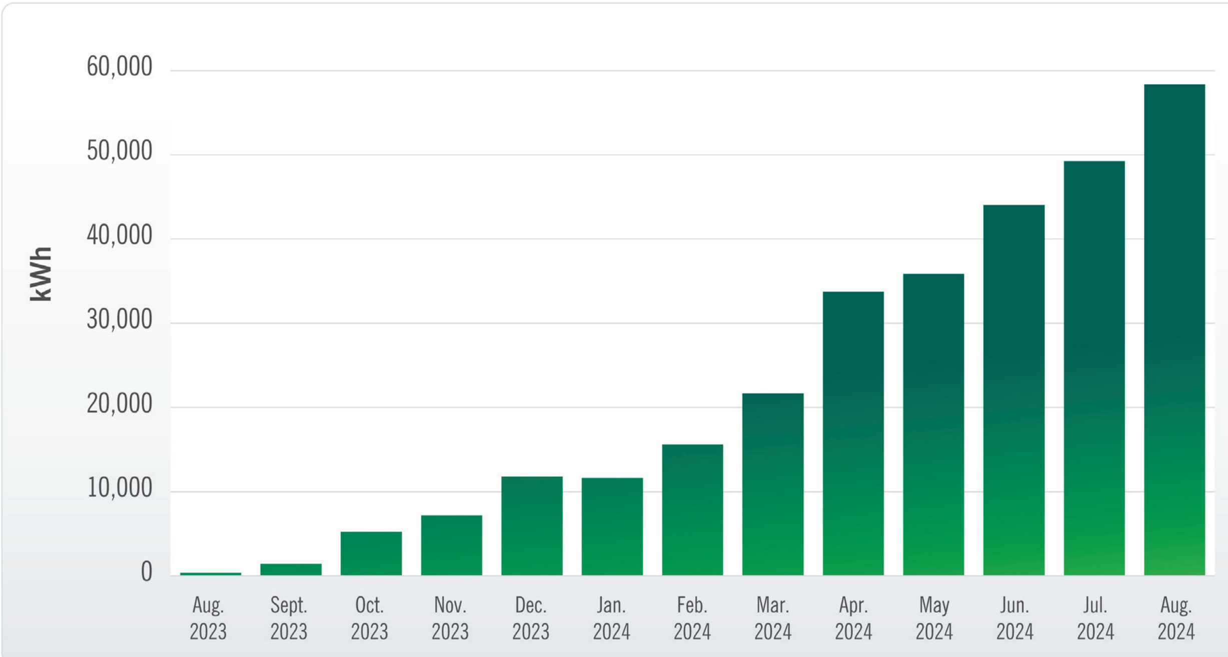


Figure H-11: Park & Plug Program Energy Dispensed



Charger Solution

The Charger Solution program offers both residential and non-residential Duke Energy Indiana customers in Indiana a term rental of various types of charging options for their home or commercial location. The fixed monthly rate, billed on the customer's regular Duke Energy Indiana bill, includes the cost of charger installation, warranty, and maintenance. Throughout the term, the customer will operate the charger and Duke Energy Indiana will retain ownership and responsibility for maintenance. The customer installs and retains ownership of make-ready infrastructure.

The residential segment has 16 participants and 48 withdrawn applications as of September 2024. The primary reason given by withdrawn customers is that they were not prepared to invest in the make-ready infrastructure required for Level 2 charging at their residence. The commercial segment has seen less interest with a single installation to date. For this segment, the Company has observed lengthy sales cycles.

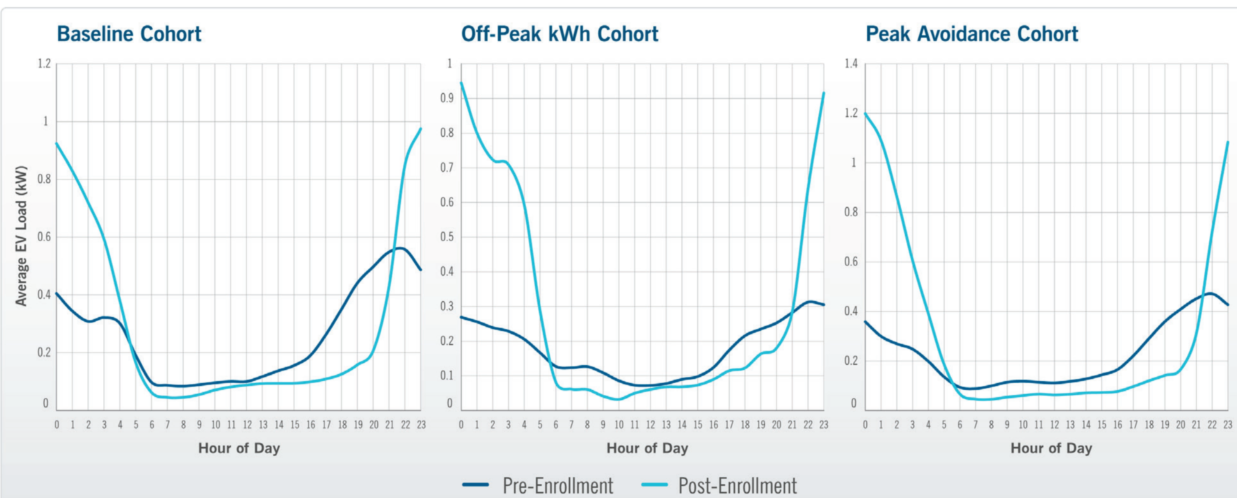
Current Two-Year Programs

The Company is wrapping up deployment of four programs that were approved in Cause No. 45616. In addition to supporting EV adoption in the state and making early inroads into managing EV charging, these limited programs were intended to help gather data about EV charging loads.

Residential Off-Peak Credit

The Off-Peak Credit program rewards customers with a $50 quarterly credit for charging their EV during off-peak hours while avoiding charging on-peak. The program allows for up to 500 residential customers to participate on a first-come, first-served basis. Customers are randomly assigned to one of three method groups to test the customers' willingness to modify their EV charging behavior. This program ran for two consecutive years, from October 2022 to October 2024. Program participation as of August 2024 was 489 customers. While intentionally limited in scale, the program has demonstrated a strong case that simple program structures can effectively shift significant EV charging load, especially in the summer peak. Figure H-12 below charts the load shift results from the three program cohorts. In all cases, a clear movement of EV charging consumption from the peak hours to overnight hours can be observed.

Figure H-12: Off-Peak Credit Program Load Shift by Cohort



Commercial Charger Rebate

The Commercial Charger Rebate program was designed to support the installation of 1,200 electric vehicle chargers for commercial customers across the Company's service territory. Upon acceptance of a customer's application and verification of proper installation of all Electric Vehicle Service Equipment ("EVSE") behind a separate meter, the customer will receive a one-time, $500 rebate incentive per EVSE installed. EVSE incentives are available to any commercial entities, public or private, including apartment dwellings, government fleets, and workplace fleets. EVSE incentives have been allocated to four segments: Public Level 2, Multi-Unit Dwelling Level 2, Workplace Level 2, and

Fleet Level 2. Private fleet customers must own, lease, or otherwise operate on a regular basis one or more plug-in electric vehicle per install.

As of August 2024, there have been 51 applications for the pilot program. Of those, four applications have been approved for 23 chargers – 20 Workplace Level 2 chargers, two Multi-Unit Dwelling chargers, and one Public Level 2 charger totaling $11,500 in rebates paid. Six applications have been pre-approved for 16 additional chargers, totaling $8,000 in rebates. Unfortunately, most applications have been disqualified or withdrawn. The majority of disqualified customers did not meet the four-charger minimum requirement, which has since been removed, or had residential accounts. Customers who withdrew applications primarily cited separate metering costs and insignificant rebate amounts as deterrents.

Vehicle-to-Grid Electric School Bus

The Vehicle-to-Grid Electric School Bus program offers $197,000 in funding per bus to school districts interested in deploying an electric bus and testing bidirectional charging functionality. As such, the program aims to not only validate an advanced technology for managing grid constraints, but also to initially quantify its value to the electric system. The program is authorized to deploy up to six buses. To date, program participation has been delayed as the Company works with districts that are seeking complementary federal funding awards. Sources of funding include the EPA Clean School Bus Program of rebates and competitive grants. Since October 2022, the EPA Clean School Bus Program has awarded $2.9 billion in funding supporting the purchase of 8,100 electric school buses across the nation. Additional rounds of funding are expected to fully disperse the total $5 million allocated for the Clean School Bus Program.

Fleet Advisory

The Fleet Advisory program offers commercial and industrial customers operating fleets a comprehensive study that analyzes potential savings for converting vehicles to electric vehicles. The studies are completed by a third-party vendor at a cost of $12,000 per study, and the Company is approved to offer up to 45 studies. To date, 14 fleets have received a completed study, and an additional four fleets are in the process of receiving a study. Approximately 3,259 on-road vehicles have been evaluated across the 14 completed studies. Of the vehicles evaluated, 1,293 are recommended for EV conversion with potential total cost of ownership savings in excess of $40 million. To power the EVs recommended for conversion, 13.37 MW of charging infrastructure was recommended. The Company engages with the participants to understand what service upgrades may be required to accommodate the added load. This information is also used by system planning experts to evaluate if adequate capacity exists on the system and if there are additional other localized concerns that should be included in distribution capacity planning upgrades.

Proposed Electric Vehicle Programs

Make-Ready Credit ("Charger Prep Credit")

The Company proposed a Make-Ready Credit program, which will be marketed as the "Charger Prep Credit," for approval with the Commission for residential customers. The Make-Ready Credit program simplifies EV adoption for the residential segment. The program provides incentives to customers including funding based on anticipated revenue from future EV charging and, if desired, a Company-directed qualified contractor to install make-ready infrastructure for EV charging in the home. The program also provides incentives to home builders for new homes that are installed with EV make-ready infrastructure. By requiring that all installations comply with local permitting requirements, the program also helps to ensure that EV charging is safely installed in customer homes.

Facilitating Charging Infrastructure

The Company is also analyzing the potential for commercial fleet electrification in Indiana, identifying potential fleet electrification clusters, and performing outreach to both national accounts as well as entities that are historically not large electric consumers. As described in the above section, "Efficiently Serving Electric Fleet Load," how the Company approaches facilitating EV adoption for this customer segment will have significant impact on the amount of grid investment that is ultimately required.

Finally, the Company has been a key partner in the planning and deployment of both IIJA and Volkswagen mitigation funding to advance transportation electrification in Indiana. For example, the Company's expertise in deploying fast charging and in electrical capacity planning within the sourcing processes of other states is being leveraged to bring efficiency to National Electric Vehicle Infrastructure ("NEVI") deployments. The Company does not anticipate seeking NEVI funding directly, but instead views the program as an opportunity for private operators in the EV charging industry to deploy foundational direct current fast charging infrastructure. As such, the Company is doing its part to assist the Indiana Department of Transportation, as well as funding recipients. The Company has also partnered with the Indiana Department of Environmental Management and other utilities to successfully leverage VW mitigation funding to deploy foundational direct current fast charging infrastructure.

Short-Term Action Plan

Programs to Implement

While no programs are currently approved and pending implementation, the Company does have a keen eye to the proposed Charger Prep Credit program. Many customers who have withdrawn from the Company's Charger Solution program have cited a lack of make-ready infrastructure assistance as a reason for not continuing participation. This signals a gap in offers available to customers, and the Company looks forward to implementation of the Make-Ready Credit program, if approved by the Commission.

Programs to Design

As noted, the Company must continue efforts to devise EV load management structures that are suitable for early stage, lower levels of adoption, as well as prepare for more sophisticated orchestration of EV charging as market saturation occurs.

The Company also notes that its proposed Make-Ready Credit program excludes the non-residential customer segment, which comprises important segments such as public DC fast charging and multi-unit dwellings. In tandem, the Commercial Charger Rebate offering has not proven to be highly attractive to customers. It is the Company's intention to develop a program offering for the commercial segment akin to the Make-Ready Credit program that is successful in supporting EVSE installations for non-residential customers in the near future.

Looking Ahead

The Company's ability to deliver load management and to serve growing electric fleets will be enabled by approval of programs as they are proposed to the Commission. As a complement to adoption-simplifying programs, such as the Make-Ready Credit program, the Company anticipates both continuing to monitor adoption levels in Indiana as well as developing EV load management offers that can be deployed cost-effectively. The Company has also filed early efforts to proactively serve fleet clusters in the current rate case and has requested to continue the fleet advisory services program. As the Company's capabilities in meeting electric fleet loads continue to evolve and deepen, support for reconsidering the traditional paradigms to serve new load will be critical.

Behind-the-Meter Generation

Behind-the-meter generation generally refers to customer-sited resources, primarily solar and solar paired with storage (approximately 15% of currently installed solar systems in Duke Energy Indiana are coupled with storage). There are specific tariffs in place applicable to customers with BTM resources that determine the compensation for energy produced from these systems. The Company currently offers the Excess Distributed Generation tariff that specifies the rate at which exports from distributed resources are valued. BTM resources could also include storage not coupled with solar, but without detailed use cases for these resources or projected counts, the modeling excludes any impacts from these resources.

Landscape

Legislative Impacts

There are several market factors and conditions that are expected to have an impact on the adoption of behind-the-meter resources. Of primary importance is the IRA; two primary provisions in the IRA that support BTM adoption include the extension of the investment tax credit ("ITC") for solar and solar paired with storage systems, and the implementation of the ITC for stand-alone storage systems. Prior to the IRA, residential solar systems were eligible for a tax credit for systems installed by the end of

2023. The IRA has extended the tax credit at a 30% rate of installed cost through the end of 2032, with installations in 2033 eligible for a 26% tax credit, and 2034 installations eligible for a 22% tax credit. A new tax credit for residential stand-alone storage has also been codified in the IRA (must be at least 3 kWh). Chapter 3 (Key Assumptions) includes a more detailed discussion of the IRA and associated modeling assumptions.

Headwinds

In contrast to the benefits of the IRA, there are challenges associated with BTM resources, particularly around market factors, as reflected in inflation and supply chain pressures. Long-range forecasts show declining price curves for solar and storage, but the market still seems to be facing inflationary headwinds. Resource availability is also an issue, with the solar supply chain concentrated in China. Even excluding geopolitical issues, the reliance on one area for most of the supply chain will result in higher risk profiles. The IRA as well as the IIJA include many programs designed to help address some of these challenges, with a goal to help reestablish domestic supply chains for both solar and storage resources, and to diversify away from a single, dominant supplier/region. Despite the legislative actions, whose impacts are more likely to be effective in the medium- to long-term, the near-term will still need to navigate around the pressures and risks associated with the market and supply chain. While keeping abreast of challenges in the behind-the-meter space, the growth of solar paired with storage resources will also warrant further analysis to help with modeling these resources. The storage component can function in multiple roles, from maximizing the value of the coupled solar to providing resiliency and outage protection. As more of these systems are installed, a more detailed understanding of their use cases will be beneficial.

One other market variable that is likely having an outsized importance on the adoption of BTM resources is the sustained high-interest rate environment, which increases financing costs, and thus reduces the economic value of these resources.

Contributions to Resource Plan

Historical Adoption Trends

Behind-the-meter resource connections have continued to grow within the Duke Energy Indiana customer base, showing a five-year compound annual growth rate of about 30% since 2019. By year-end 2023, approximately 0.5% of Duke Energy Indiana's residential customers had installed solar and/or solar paired with storage.

Figure H-13 shows the growth in both BTM connections (customer adoption) and the associated capacity in Duke Energy Indiana since 2019. Figure H-14 below shows the total number of BTM customers as of the end of 2023 as well as the projected energy for 2024 to be generated from these systems.

Figure H-13: Historical Behind-the-Meter Customer Connections and Capacity

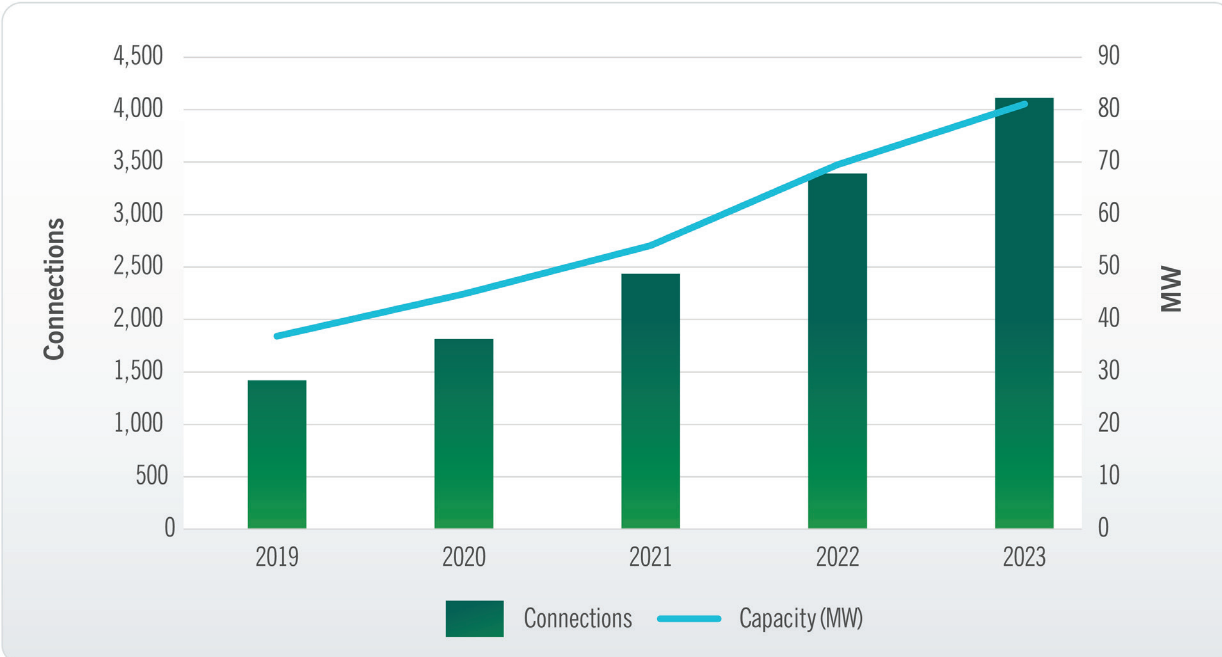
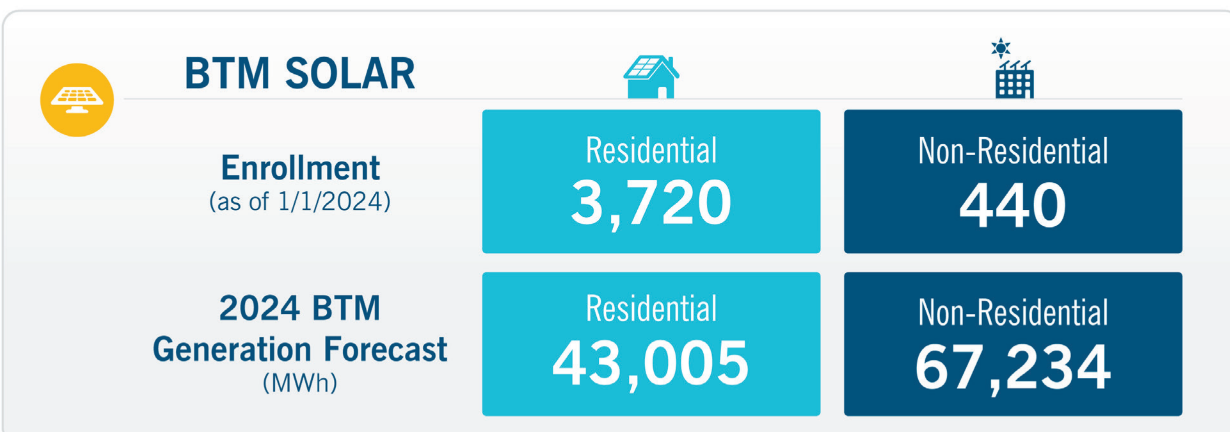


Figure H-14: Duke Energy Indiana Customers Enrolled as of 1/1/2024 & Total Forecasted Behind-the-Meter Generation in 2024



Note: Figure H-14 shows energy (MWh) calculated for existing connections as of January 1, 2024 (does not include the energy from additions during 2024).

Forecasted Behind-the-Meter Adoption

Adoption of behind-the-meter generation is expected to continue to grow throughout the forecast period, with total residential systems projected to reach about 1.5% of customers in 10 years. This reflects an annual growth rate of approximately 10% over this period. Figure H-15 to the right shows the expected additional BTM customer counts by the end of 2034 along with estimates of the energy from these systems.

Forecasted BTM adoption and impacts to the 2024 IRP load forecast are discussed in detail in Appendix D.

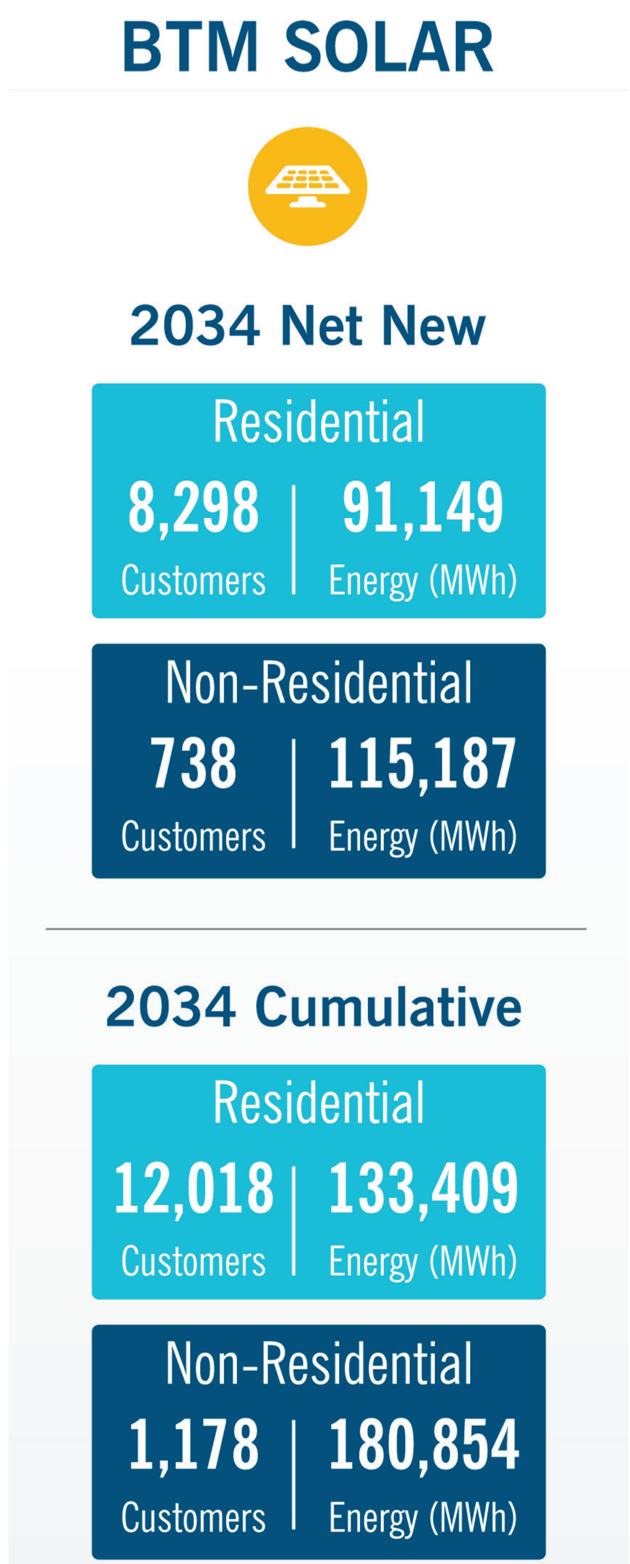


Figure H-15: Forecasted BTM Customers & Generation by 2034 (right)

Note: The "net new" data provided in Figure H-15 represents the forecasted incremental number of customers adopting BTM solar between 1/1/2024 and 12/31/2034, and the associated energy generated by these systems for the year 2034. The cumulative data represents the projected total number of BTM customers and the associated energy for these systems for the year 2034.

Enablers

While not the only variable, economics will have a large impact on BTM adoption rates. Thus, factors that impact the economics of BTM resources will be key enablers, or impediments to adoption. Duke Energy Indiana will continue to monitor system costs, incentives, interest rates, inflation rates, borrowing rates, and other market dynamics that are expected to impact the economic equation associated with BTM resources so that future projections can be adjusted to reflect changing market conditions.

One example of this is the Solar for All program. The EPA announced $7 billion in Solar for All grants in April 2024 to deliver residential solar projects. A coalition of Indiana organizations and cities were chosen to receive approximately $117 million in funding to provide access to solar energy to low-income and disadvantaged households. Program details have not been released, but it is expected that the funding will support both customer-sited and community solar projects. While the Indiana grant is statewide, it is likely that some level of the support will be utilized within the Company's service territory to help promote additional behind-the-meter resources.

Short-Term Action Plan

Duke Energy Indiana continues to look for ways to educate and help make the process of considering and adopting renewable generation easier for customers. There are several resources available on the Company's website. The "Generate Your Own" webpage provides an Interconnection Overview, which includes generation options and details on how to get support.[1] Customers can also get connected with trusted solar installers that have been vetted by the Company at Find It Duke.

Clean Energy Customer Programs

Landscape

Across the U.S., there is increasing demand for and adoption of clean energy programs offered by utilities. According to the National Renewable Energy Laboratory ("NREL"), about 1,252,000 customers in the U.S. procured about 16.6 million MWh of voluntary green power through utility clean energy programs in 2022, which is over a 200% increase in adoption in less than a decade.[2]

Duke Energy Indiana continues to hear from its customers that they are looking for ways to achieve their own sustainability goals, which may include renewable energy and carbon-free targets. For example, customers are looking for access to RECs, a common type of clean energy program which allows the customer to lower their Scope 2 carbon emissions from electricity purchased from the grid while supporting the local renewable sector. A REC represents the environmental attributes of one megawatt-hour of electricity generated from renewable energy sources, such as solar and wind. Customers can purchase RECs to match some or all of their electricity usage with carbon-free energy, allowing them to find the best combination of options to reach their sustainability goals.

Current Programs

While installing solar on-site may be an option for some customers, clean energy programs are designed to offer alternative and/or complimentary options such as RECs. Duke Energy Indiana offers and continues to innovate clean energy programs to provide customers greater accessibility to renewable, carbon-free energy without some of the barriers that may be in place with installing customer-sited solar. For example, a residential customer may be a renter or live in a multi-family dwelling, may be looking for a short-term solution without a long-term contract, or may not be in a position to make a capital investment. For commercial customers, there may be insufficient physical space for a system size to meet their energy needs, or they may be seeking a more cost-effective,

[1] Duke Energy, Generate Your Own Renewable Energy, available at https://www.duke-energy.com/business/products/renewables/generate-your-own.

[2] NREL, Status and Trends in the U.S. Voluntary Green Power Market 2022 Data, April 2024, available at https://www.nrel.gov/docs/fy24osti/88219.pdf.

flexible, and less complex way to participate in renewable energy. Duke Energy Indiana's voluntary clean energy programs allow customers to overcome these barriers to accelerate their sustainability journey, and these programs are designed in a way to ensure non-participants are not impacted by the programs.

Go Green

Program participants can match their electricity usage by purchasing blocks of RECs. This is a month-to-month program that doesn't require a long-term commitment and is flexible on the number of blocks a customer can purchase. Customized options are also available for business customers.

To enhance this program, the Company has filed to begin using locally sourced RECs vs. purchasing them off the market to use for this program. This proposed change is a direct result of feedback from customers that they want to purchase local RECs to support clean energy development in their communities. Revenue from the sale of these locally sourced RECs would also go back to benefit all Duke Energy Indiana customers.

Green Source Advantage

Green Source Advantage ("GSA") allows eligible non-residential customers the option to participate in a green energy program that can match up to 100% of their annual usage. GSA is designed to give customers flexibility and options to directly negotiate long-term contracts with third-party renewable suppliers of their choice, while remaining on the Company's standard rate tariff. GSA introduces new green energy sources to the MISO grid without burdening customers with the requirement to own land or expend their capital budget while also keeping non-participants held harmless. Participating customers will also receive all the RECs for the correlated renewable energy production of the new resource.

Future Concepts Under Consideration

Duke Energy Indiana continues to explore opportunities to expand its clean energy programs. For example, the Company is evaluating a community solar program, which would be modeled after the success of the Clean Energy Connection program in Duke Energy Florida. A community solar program utilizes large-scale solar facility(ies) and offers customers the ability to sign up for a share of the solar capacity. Customers would have a monthly subscription charge on their bill correlated to the amount of kW they sign up for as well as a bill credit for the kWh production. Customers would also have rights to RECs, which allows customers to claim the use of the renewable, carbon-free energy. Program participation carve-outs would be available for all customer types: residential, business, and income qualified. Income qualified customer options would be designed in a way to provide those customers an immediate monthly cost savings. The Company is also open to collaborate with local agencies on Solar for All funding to provide community solar opportunities to customers.

Short-Term Action Plan

In October 2024, the Commission approved the tariff for the GSA program. The Company will work with large customers to help navigate the MISO settlement process and hopefully add additional renewable projects to the MISO Zone 6 footprint. In addition, as Duke Energy Indiana adds more renewable assets to its generation mix, the Company will look to add programs like community solar. The Preferred Portfolio in this report will be the guide on when those renewables will be needed and when such a program would be filed with the Commission. Duke Energy Indiana will also work with individual recipients of Solar for All grants to develop smaller (up to 5 MW) community solar projects in the coming years.

Regarding other clean energy programs, the Company is awaiting Commission approval of the Go Green enhancement to provide locally sourced RECs.

Appendix I: Transmission Planning

Highlights

- The transmission system of Duke Energy Indiana (the "Company") is adequate to support load growth, resource plan retirements and integration of new resources, and the expected power transfers over the next 10 years if the planned transmission system expansions are completed as currently scheduled.
- Long Range Transmission Plan projects are expected to bring diverse benefits to Duke Energy Indiana customers such as congestion relief and fuel savings, avoided capital cost of local resource investment, avoided transmission investment, resource adequacy savings, and avoided risk of load loss based on analyses conducted by the Midcontinent Independent System Operator ("MISO").
- The MISO Definitive Planning Phase interconnection queue process takes four to five years to go from submitting an interconnection request for a resource to executing a Large Generator Interconnection Agreement. This delayed process can have material impacts on the execution of the Company's resource plan.

Transmission System

The Duke Energy Indiana bulk transmission system is comprised of 345 kilovolt ("kV"), 230 kV, and 138 kV systems. The 345 kV system serves primarily to deliver bulk power from Duke Energy Indiana's large generating units into and/or across the service area and interconnects the Duke Energy Indiana system with other neighboring systems. The 345 kV system distributes bulk power to numerous substations across the system, where large transformers connect the bulk system to the 230 kV and 138 kV lower voltage sub-transmission systems and distribution circuits, or directly to large customer loads. These 138 kV and 230 kV systems distribute power received through the transformers and from several smaller generating units, which are connected directly at these voltage levels.

Because of the numerous interconnections Duke Energy Indiana has with neighboring local balancing areas, the Company's transmission system increases electric system reliability and decreases costs to customers by permitting the exchange of power and energy with other utilities on an emergency or economic basis.

Duke Energy Indiana, Wabash Valley Power Alliance ("WVPA") and Indiana Municipal Power Agency ("IMPA") together own the Joint Transmission System ("JTS") in Indiana. It consists of 727 circuit miles of 345 kV, 654 circuit miles of 230 kV, 1,393 circuit miles of 138 kV, and 2,502 circuit miles of 69 kV owned by Duke Energy Indiana. The three owners have rights to use the JTS. Duke Energy Indiana is directly interconnected with seven other local balancing authorities (American Electric Power, Louisville Gas and Electric Energy, Ameren, Hoosier Energy, Indianapolis Power and Light, Northern Indiana Public Service Company, and CenterPoint Energy), plus Duke Energy Ohio.

As a member of the MISO, Duke Energy Indiana participates in the MISO planning processes and is subject to MISO overview and coordination mechanisms. All of Duke Energy Indiana's transmission facilities, including those transmission facilities owned by WVPA and IMPA, but operated and maintained by Duke Energy Indiana, are included in these MISO planning processes. Additional coordination occurs through a variety of mechanisms, including Reliability First Corporation ("RFC") and joint meetings with the other entities held as necessary.

Transmission & Distribution Planning Process

Transmission and distribution ("T&D") planning is a complex process that requires the evaluation of numerous factors to provide meaningful insights into the performance of the system. Duke Energy Indiana's distribution system planners gather information concerning actual distribution substation transformer and line loadings. The loading trend for each transformer is examined, and a projection of future transformer bank loading is made based on the historic load growth combined with the distribution planners' knowledge of load additions within the area. The load growth in a distribution planning area tends to be somewhat more uncertain and difficult to predict than the load forecasts made for Duke Energy Indiana as a whole.

Customers' decisions can dramatically impact the location and timing of future distribution capacity and system improvement projects. Because of this uncertainty, distribution development plans are under continual review to confirm proposed projects remain appropriate for the area's needs.

T&D planning generally depends on the specific location of the loads; therefore, the effects of co-generation capacity on T&D planning are location specific. To the extent that fewer new T&D resources are required to serve these customers or the local areas in which they reside, Duke Energy Indiana's T&D planning will reflect this change.

Adding new distribution substation capacity to an area typically takes 36 to 48 months. Factors related to the future customer load, such as local knowledge of growth potential based on zoning, highway access, and surrounding development, can help forecast ultimate distribution system needs.

Transmission system planners utilize the historical distribution substation transformer bank loading and trends, combined with the Duke Energy Indiana load forecast and resource plan and firm service schedules, to develop models of the transmission system. These models are used to simulate the transmission system performance under a range of credible conditions to ensure that expected performance meets both North American Electric Reliability Corporation ("NERC") and Duke Energy Indiana planning criteria. Should these simulations indicate that a violation of the planning criteria occurs, more detailed studies are conducted to determine the severity of the problem and possible measures to alleviate it.

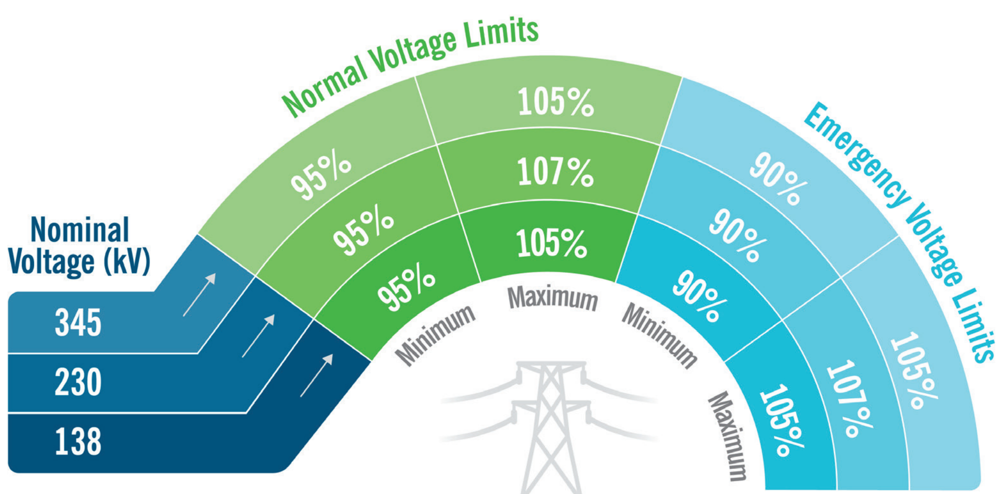
Duke Energy Indiana's planning criteria are filed under the Federal Energy Regulatory Commission ("FERC") Form 715 Part 4. The Company adheres to any applicable NERC and RFC Reliability Standards and to its own detailed planning criteria described below. Violations of these criteria would require expansion of the transmission system and/or new or revised operating procedures. Acceptance of operating procedures is based on engineering judgment with the consideration of the probability of violation weighed against its consequences and other factors.

Transmission Planning Criteria

Voltage

Bus voltages are screened using the transmission system voltage limits in Figure I-1 below. These limits specify minimum and maximum voltage levels during both normal and contingency conditions. Emergency Voltage Limits are defined as the upper and lower operating limits of each bus on the system. Voltage limits are expressed as a percent of nominal voltage. All voltages should be maintained within the appropriate emergency voltage limits.

Figure I-1: Transmission System Voltage Limits



Thermal

The following guidelines shall be used to ensure acceptable thermal loadings:

- In normal conditions, no facility should exceed its continuous thermal loading capability.
- For a single contingency, no facility should exceed its emergency loading capability.

Stability

The stability of the Duke Energy Indiana system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC and RFC Reliability Standards. Generating units must maintain angular, voltage, and frequency stability under various contingency situations. Many different contingencies are considered, and the selection is dependent on the location within the transmission system.

Fault Duty

All circuit breakers should be able to interrupt the maximum fault current duty imposed on them.

Single Contingencies

The thermal and voltage limits should not be violated for either normal operations or under the loss of:

- A single transmission circuit
- A single transformer
- A single generating unit
- A single reactive power source or sink

Severe Contingencies

NERC Reliability Standards include evaluation of extreme (highly improbable) contingency events causing multiple elements to be removed or cascade out of service. Severe contingencies are evaluated to determine the impact on the Duke Energy Indiana and interconnected transmission systems. These evaluations are not intended to be absolute or applied without exception. Other factors, such as severity of consequences, availability of emergency switching procedures, probability of occurrence and the cost of remedial action are also considered in the evaluation of the transmission system.

New Generation Resource Interconnection Studies

Duke Energy Indiana participates in regional generation interconnection studies for proposed generation interconnections inside the MISO footprint. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the

Duke Energy Indiana system to maintain system reliability. Power flow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions. New generation resources within the MISO footprint seeking to connect to the transmission system will be subject to the interconnection requirements described in the MISO Tariff and applicable MISO Business Practice Manuals. In order to interconnect to the transmission system, the resource owner must provide project details including location, resource size, type of service requested, when it wants to connect, and any other relevant details. After this information has been received, the impacted Transmission Owner and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably interconnect the generation resource to the transmission system.

Evaluation of Adequacy for Load Growth

The transmission system of Duke Energy Indiana is adequate to support load growth and the expected power transfers over the next 10 years if the planned transmission system expansions are completed as currently scheduled. The latter half of this Appendix includes details on the major planned transmission projects. Duke Energy Indiana’s transmission system can be significantly affected by the actions of others. In an attempt to evaluate these effects, MISO develops a series of power flow simulation base cases that reflect the expected transmission system configuration and expected power transfers. Should actual conditions differ significantly from those assumed in the base cases, a re-evaluation of the adequacy of the Duke Energy Indiana transmission system would be required.

Economic Loss Evaluation

As a member of MISO, Duke Energy Indiana actively participates in the MISO Transmission Expansion Planning (“MTEP”) assessment and study processes, which include economic analysis. MISO utilizes Promod, a commercial production cost model, to evaluate potential economic benefits of transmission projects or portfolios. Production cost model simulations are performed with and without each developed transmission project or portfolio. Taking the difference between these two cases provides the economic benefits associated with each project or portfolio. The economic benefits include adjusted production cost savings, reduced energy and capacity losses, and reduced congestion cost. Projects that meet initial qualification criteria will be further evaluated under the appropriate MISO or interregional planning process.

Transmission Expansion

The transmission system expansion plans for the Duke Energy Indiana system are developed to meet the projected future requirements of the transmission system using power flow analysis. Power flow representations of the Duke Energy Indiana electric transmission system, which allow computer simulations to determine megawatt (“MW”) and megavolt-ampere reactive power flows and the voltages across the system, are maintained for the peak periods of the current and future years. These power flow base cases simulate the system under normal conditions with typical generation and no transmission outages. They are used to determine the general performance of the existing and planned transmission system under normal conditions.

Contingency cases based on the peak load base cases are studied to determine system performance for planned and unplanned transmission and generation outages. The results of these studies are used to determine the need for and timing of additions to the transmission system. As indicated earlier, Duke Energy Indiana, as a member of the MISO, actively participates in the MISO MTEP assessment and study processes by reviewing the modeling data, providing simulation scenarios, and reviewing and providing feedback on the results of MTEP assessments and studies. All of Duke Energy Indiana's transmission facilities, including those transmission facilities owned by WVPA and IMPA, but operated and maintained by Duke Energy Indiana, are included in these MISO processes. In addition, MISO reviews Duke Energy Indiana's proposed plans and makes comments and suggestions. Ultimately, MISO has responsibility for the development of the regional transmission plan. MTEP 24 assessed the Duke Energy Indiana transmission system for the period 2024 through 2034 with simulations for years 2024, 2025, 2026, 2029 and 2034. These models were utilized to simulate both steady state and dynamic performance under a wide variety of credible conditions, such as Summer Peak, Shoulder Peak and Light Load, to ensure that expected performance meets both NERC and Duke Energy Indiana planning criteria. The MTEP studies provide an indication of system performance under a variety of conditions to guide the development of a comprehensive expansion plan that meets both reliability and economic expansion needs. The planning process identifies solutions to reliability issues that arise from the expected dispatch of network resources. These solutions include evaluating alternative costs between capital expenditures for transmission expansion projects, nontraditional transmission solutions such as Dynamic Line Ratings, batteries and increased operating expenses from re-dispatching network resources or other operational actions.

Transmission Expansion Plans

Major Planned Transmission Projects

There is a comprehensive list of Duke Energy Indiana planned transmission projects contained in MISO's MTEP 2024, including new substation transformers, transmission capacitors, transmission circuits, and upgrades of existing circuits and substations. A subset of the major planned transmission projects are described below.

Clark County Logistics

The Clark County Logistics project provides a networked feed to a new large economic development customer. The substation will be built out to include five 138 kV breaker-and-a-half rungs to loop in the 13898, provide four feeds to the customer, provide three positions for three 345/138 kV 450 megavolt-ampere ("MVA") transformers and one future position.

Surefire Solar

The Surefire Solar project consists of a new three breaker ring bus to connect a new 200 MW solar farm to the power system. The ring bus will connect to the Cayuga to Sugar Creek line. The new ring bus will connect approximately 18 miles south of the Cayuga generating station. In addition to connecting the solar farm, this project will reduce 345 kV line exposure.

Locomotive Solar

The Locomotive Solar project consists of expanding the Greentown 230 substation to connect a new 152.23 MW solar farm to the power system. The project will expand the 230 kV ring bus to include an additional ring bus position for the solar farm's interconnection.

Greentown Solar

The J1481 Greentown Solar project consists of expanding the Greentown 230 substation to connect a new 200 MW solar farm to the power system. The project will expand the existing 230 kV ring bus to include an additional ring bus position for the solar farm's interconnection.

Kokomo Industrial Substation

The Kokomo Industrial Substation project provides a networked feed to a new economic development customer. The networked feed will consist of a new 230 kV ring bus and 69 kV breaker-and-a-half. The 230 kV ring bus will connect to the Kokomo East to Kokomo Chrysler line.

Economic Projects

Duke Energy Indiana continues to stay abreast of MISO expansion criteria and participate in MISO studies and evaluate transmission projects that provide economic value to Duke Energy Indiana customers.

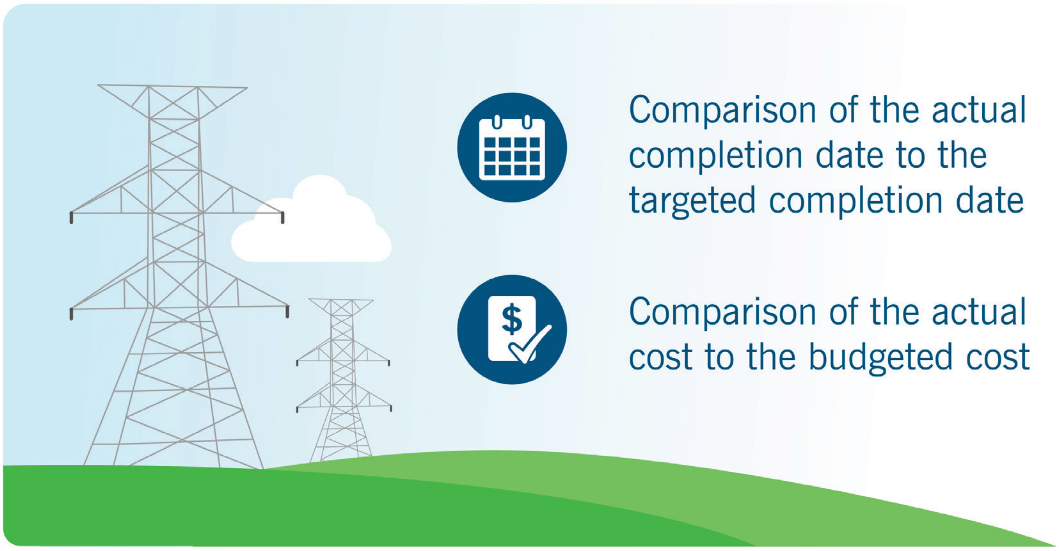
Planning analyses performed by MISO test the transmission system under a wide variety of conditions using standard industry applications to model steady state power flow, angular and voltage stability, short-circuit, and economic parameters, as determined appropriate by MISO to be compliant with applicable criteria and the MISO Tariff.

Short-Term Implementation Plan for Planned New Transmission Facilities

Criteria & Objectives for Monitoring Success

Milestones and criteria used to monitor the transmission facilities projects are typical of construction projects and are measured on factors shown in Figure I-2 below.

Figure I-2: Criteria and Objectives for Monitoring Success



Anticipated Time Frame & Estimated Costs

The status and cash flows associated with the planned major transmission facility projects are shown in Tables I-1 and I-2 below.

Table I-1: Status Updates and Changes from Previous Reports

				Cash Flow ($000)		
Project Name	**Miles or MVA**	**kV**	**Completion**	**2024**	**2025**	**2026**
Mitchell Lehigh[1]	8	138	12/27/2021	$0	$0	$0
Switching Station[2]	345	345	11/28/2023	$(204)	$0	$0
Hardy Hills Switching Station[3]	–	230	2/9/2024	$2	$0	$0
NW Tap to Lafayette Cincinnati St. Rebuild	11.2	138	6/1/2023	$1,835	$0	$0
Lafayette South to Shadeland Rebuild	3.4	138	12/27/2024	$6,466	$0	$0

Note 1: Project is partially funded by IMPA as part of their obligations as joint owner of the Duke Energy Indiana transmission system.

Note 2: Project to be reimbursed by developer.

Note 3: Project is to be self-built by interconnection customer. Along with transmission line work costs, costs include oversight of customer construction. Project to be reimbursed by developer.

Table I-2: Current Planned Duke Energy Indiana Transmission Projects

				Cash Flow ($000)		
Project Name	**Miles or MVA**	**kV**	**Completion**	**2024**	**2025**	**2026**
Clark County Logistics	–	138	8/19/2026	$1,970	$45,195	$13,009
Surefire Solar Switching Station[1,2]	–	345	9/1/2026	$286	$108	$4,100
Locomotive Solar[2]	–	230	6/15/2026	$81	$205	$3,459
Greentown Solar[2]	11.2	230	6/15/2026	$167	$295	$5,219
Kokomo Industrial	3.4	230	12/7/2026	$8,840	$58,073	$18,836

Note: All costs exclude allowance for funds used during construction.

Note 1: Project is partially funded by IMPA as part of their obligations as joint owner of the Duke Energy Indiana transmission system.

Note 2: Project to be reimbursed by developer.

Anticipated Project Milestones

The completion of these projects, by their planned in-service dates and costs, are the project milestones.

Transmission Upgrades Needed for Interconnection of Incremental Resources Identified in the Preferred Resource Plan

Midcontinent Independent System Operator Generator Interconnection Process

MISO's generator interconnection process vets and approves the addition of new energy sources into the MISO-controlled transmission network. It also manages generation retirement decisions to ensure that there's enough incoming energy to replace what is phased out. It's a non-discriminatory access system, open to generators within the MISO territory. A successful application will result in an interconnection agreement that allows a connection to the MISO grid.[1]

MISO studies resources requesting interconnection to the MISO grid through its Definitive Planning Phases ("DPP") study process. Each DPP cycle has three phases:

> **Phase 1**: Provides the interconnection customer with a preliminary detailed analysis of their interconnection request's impact on the reliability of the transmission system.

[1] Midcontinent Independent System Operator, Inc., Generator Interconnection and Retirement, available at https://www.misoenergy.org/planning/resource-utilization/generator-interconnection/.

Phase 2: Provides the interconnection customer a revised and detailed analysis of their interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions resulting from the withdrawal of interconnection requests during DPP 1.

Phase 3: Provides the interconnection customer a final, detailed analysis of their interconnection project's impact on the reliability of the transmission system after incorporating updated generation assumptions due to potential withdrawal of interconnection requests during DPP 2.

Upon completion of the DPP, the parties enter into final negotiations to create the Generator Interconnection Agreement ("GIA"). Once an agreement is reached, MISO files the agreement with FERC.[2]

The current MISO DPP Study Schedule (as of September 1, 2024) for MISO-Central is provided in Table I-3 below.

Table I-3: MISO-Central DPP Study Schedule Update – Central Region

DPP-Study Cycle	No. of Projects	MW	DPP Start	DPP 1 Completion	DPP 2 Completion	DPP 3 Completion	GIA Execution	Current Stage/ Status
2018-APR	34	7,344	4/22/2019	1/7/2020	3/10/2021	1/8/2024	6/6/2024	GIA in Progress
2019-Cycle	81	13,216	6/23/2020	8/5/2021	5/20/2022	1/26/2024	5/13/2024	GIA in Progress
2020-Cycle	43	7,035	3/15/2021	7/14/2023	8/30/2024	11/2/2024	3/17/2025	DPP 2
2021-Cycle	119	17,586	12/8/2021	10/4/2024	1/14/2025	3/11/2025	7/24/2025	DPP 1
2022-Cycle	283	51,762	3/27/2023	1/31/2025	5/13/2025	7/8/2025	11/20/2025	DPP 1
2023-Cycle	207	37,035	2/28/2025	6/8/2025	9/18/2025	11/13/2025	3/28/2026	Application

To allow for interconnection of each incremental generator reflected in the Duke Energy Indiana's 2024 Integrated Resource Plan ("IRP") to serve customer demand in the Duke Energy Indiana service territory, one of the following must occur:

- Duke Energy Indiana must enter into a purchase power agreement with a generator that has, or is receiving, a GIA through MISO's generator interconnection process.
- Duke Energy Indiana must purchase a generator that has, or is in the process of receiving, a GIA through MISO's generator interconnection process.

[2] Midcontinent Independent System Operator, Inc., Generator Interconnection and Retirement – Application Process, available at https://www.misoenergy.org/planning/resource-utilization/generator-interconnection/.

- Duke Energy Indiana must submit a GIA and enter MISO's DPP study determining the necessary transmission network upgrades needed to facilitate interconnection and move forward in the process to a GIA.
- If applicable where a replacement generator is replacing retired generation at the similar point of interconnection, Duke Energy Indiana must enter MISO's Generator Replacement Process for study and receipt of a GIA for the replacement generation. This process is used in lieu of the DPP Study process if the replacement generation capacity is the same or lower.

Generator interconnection and transmission service request impacts to the Duke Energy Indiana transmission system are studied in accordance with these MISO study processes. Through Duke Energy Indiana's participation in these processes, it can ensure the studies are performed in a manner such that the requested interconnections are incorporated into the Duke Energy Indiana system and stability and reliability are maintained. In studying the interconnection requests and transmission service requests, MISO performs power flow, short-circuit, and stability analyses to evaluate the transmission system impacts. If transmission system needs are identified in the system impact studies, additional studies are performed to develop proposed solutions that are needed to reliably interconnect the resources. Furthermore, generation resources seeking to interconnect to the transmission system within MISO footprint must adhere to interconnection requirements in the MISO Tariff and MISO Business Practice Manuals.

MISO's generator interconnection process and associated DPP study will determine the shared transmission network upgrades and associated cost estimates for each generator interconnection request. Generators entering this process proceeding on to a Generator Interconnection Agreement will receive more refined, updated transmission network upgrade costs and timeline associated with the generator interconnection as the studies progress. As reflected in Table I-3 above, the MISO interconnection queue process has been taking four-to-five years to go from submitting an interconnection request for a resource to executing a Large Generator Interconnection Agreement ("LGIA"). This process is designed to take just over one and a half years to transition from a generator interconnection request to an executed LGIA. With increasing volumes of resources requesting interconnection through the requests made in the 2023 DPP cycle, there is little reason to believe the current four-to-five-year duration from submitting an interconnection request to signing an executed interconnection agreement will improve. MISO has proposed queue reform efforts and adjusted penalties for early withdrawal and site control provisions to attempt to reduce the queue going forward. However, more reform is needed in the near-term to get current projects through the queue, as it is becoming a long lead time constraint in bringing new resources online.

Transmission Network Upgrade Cost Determinants Associated with Interconnection of Incremental Generation in Duke Energy Indiana

The results of the 2020 MISO DPP study Phase One reflected an average cost of $0.275/W for network upgrades needed to facilitate interconnection of the generators in Indiana (Zone 6) requesting interconnection. Duke Energy Indiana used this average cost in Encompass IRP modeling for units that did not include a specific transmission network upgrade cost or an assumption that the project would use the generator replacement interconnection process. Although the MISO 2020 DPP Phase Two results were produced too late for use in Duke Energy Indiana's capacity expansion plan modeling, an analysis of the 2020 MISO DPP study Phase Two average cost for network upgrades needed to facilitate interconnection of the generators in Indiana (Zone 6) revealed a less than 1% change from the $0.275/W average cost used in the capacity expansion plan modeling.

Location, MW of interconnection requested, resource/load characteristics, and number of queued requests for the given study, in aggregate can have wide ranging impacts on transmission network upgrades and associated costs required to approve the interconnection request for a new resource. Also, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Escalation of labor, materials, environmental, siting, and permitting costs have recently been significant, and this inflation of costs could be sustained into future years. In addition to risks associated with costs, the duration of constructing and placing network upgrades in service is likely to extend as more competing upgrades and associated line outages become difficult to coordinate in a given window of time. Also, to facilitate meeting necessary deadlines for placing new transmission lines and substations in service, policies and approvals for siting and permitting will need to allow for expediting and streamlining associated processes. The timing and nature of these future projects could also be dependent on any affected system network upgrades that are required.

Long-Term Transmission Planning

Duke Energy Indiana participates in MISO reviews and studies regarding long-term transmission planning. As MISO has explained:

> MISO has a Reliability Imperative, which is the term MISO uses to describe the shared responsibility that MISO, its members, and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's response to the Reliability Imperative consists of a host of interconnected initiatives that aim to address the region's challenges in a comprehensive and prioritized fashion. These initiatives are organized into four primary pillars and the long-range transmission plan ("LRTP") process is a key component of the Transmission Evolution pillar. LRTP is needed to determine how transmission can help ensure a reliable future system as the resource portfolio shifts, extreme weather events become more frequent, and demand for power increases. The need for LRTP is urgent, given the resource changes already happening, the speed of portfolio change desired by many of MISO's members, and the length of time it takes a transmission project to go from concept to reality. Not only is there an increased urgency to identify future transmission solutions, but these

> solutions must also holistically address the needs of the MISO region. Tackling these future energy needs requires a larger regional approach. LRTP looks comprehensively at MISO's region and is very much a collaborative effort with stakeholders.[3]

MISO follows a 7-Step process to perform its top-down transmission planning process, including LRTP.

1. Develop scenario-based Futures with load forecast, generation forecast, and siting results.
2. Develop models utilizing Futures and test system performance.
3. Identify potential transmission issues.
4. Propose solutions to issues.
5. Develop models with proposed solutions and evaluate the effectiveness of various solutions.
6. Recommend preferred solutions for MTEP implementation.
7. Apply appropriate cost allocation.

MISO has conducted LRTP studies to produce a Tranche 1 portfolio of transmission projects that have been approved and are proceeding toward construction. MISO continues to perform LRTP studies using results of the analysis to inform additional tranches of this plan. MISO is currently developing the LRTP Tranche 2.1 transmission project portfolio. A map of the approved Tranche 1 transmission projects and the Tranche 2.1 projects under development as of July 12, 2024, are provided in Figures I-3 and I-4 below.

[3] Midcontinent Independent System Operator, Inc, Long Range Transmission Planning Tranche 2 – Frequently Asked Questions, July 10, 2024 available at https://cdn.misoenergy.org/MISO+Long-Range+Transmission+Planning+LRTP+Tranche+2+FAQs631005.pdf.

Figure I-3: Approved LRTP Tranche 1 Transmission Projects

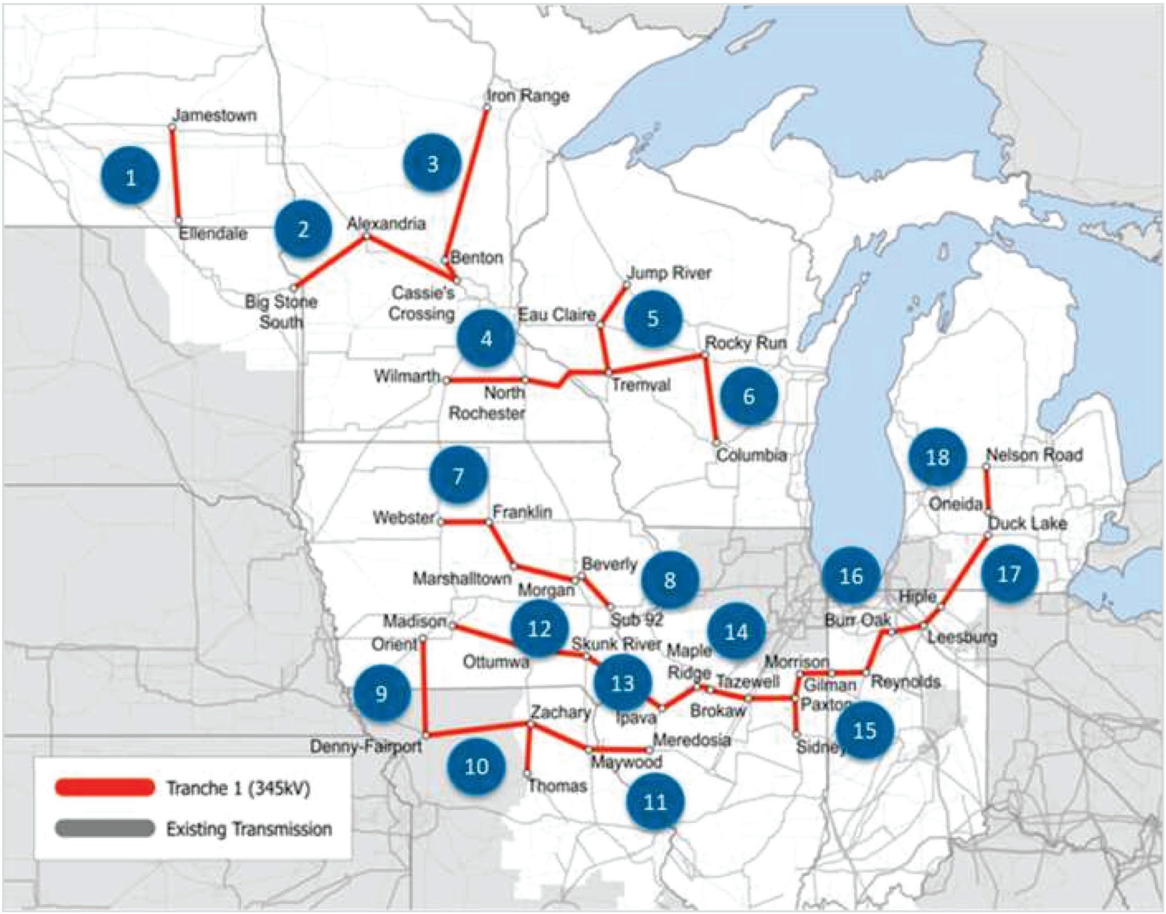
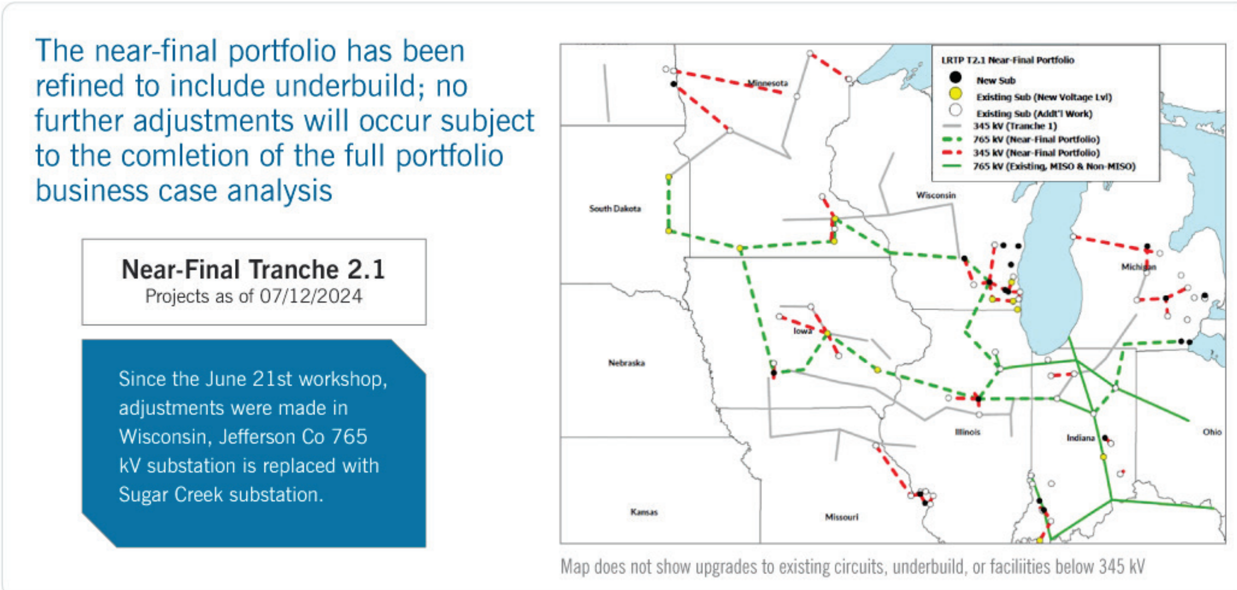


Figure I-4: Tranche 2.1 Draft Anticipated Portfolio as of July 12, 2024



MISO, through its project evaluation process, analyzes and quantifies multiple benefits associated with the LRTP transmission projects to ensure the benefit-to-cost ratios reflect material value for customers. MISO's Business Case Analysis process contains detailed business case assumptions (i.e., inflation, discount rate etc.) as well as detailed calculations on individual benefits, net present value of benefits and cost allocation. The benefits detailed in the project evaluation include congestion and fuel savings, avoided capital cost of local resource investment, avoided transmission investment, resource adequacy savings, avoided risk of load loss, decarbonization.[4] Figure I-5 below reflects the range benefit-to-cost ratios for Tranche 1 transmission projects determined for Cost Allocation Zones within MISO.

[4] Midcontinent Independent System Operator, Inc., LRTP Tranche 1 Detailed Business Case Analysis, available at https://cdn.misoenergy.org/LRTP+Tranche1+Detailed+Business+Case+Analysis625787.xlsx

Figure I-5: Benefit-to-Cost Ratios for MISO LRTP Tranche 1 Projects

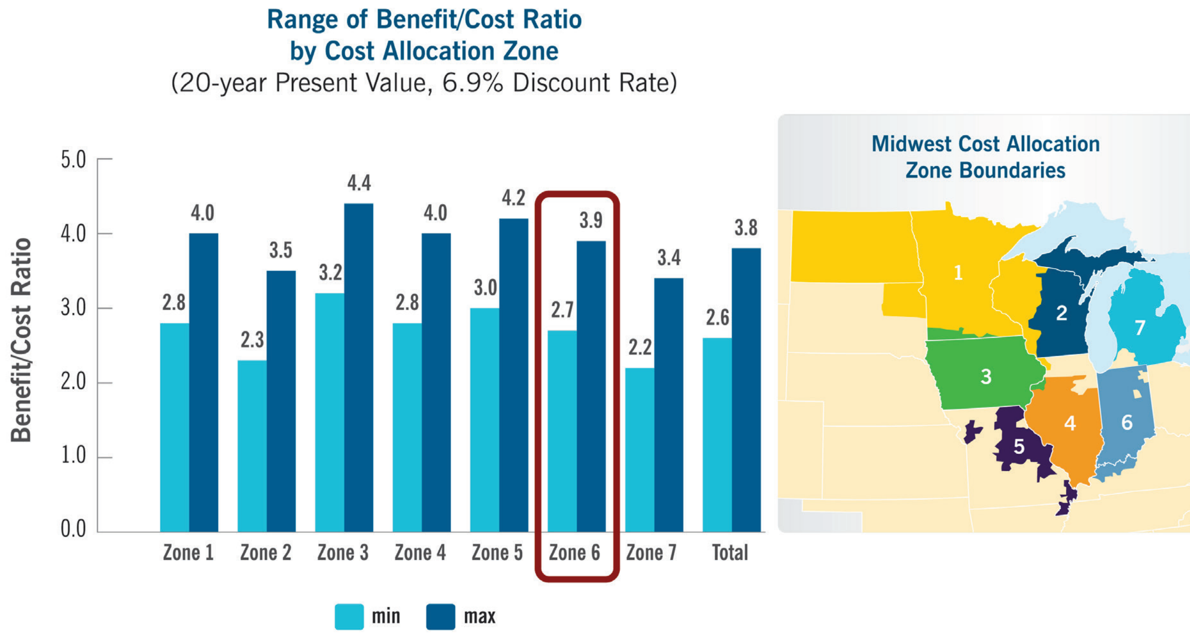


Table I-4 is a list of the LRTP Tranche 1 Projects, including their expected in-service dates ("ISD") and cost estimates.

Table I-4: LRTP Tranche 1 Projects and Project Cost

ID	Description	Expected ISD	Est. Cost ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South - Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range - Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth - North Rochester – Tremval	6/1/2028	$689
5	Tremval - Eau Claire – Jump River	6/2/2028	$505
6	Tremval - Rocky Run – Columbia	6/3/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/3/2029	$673

13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/3/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/3/2029	$261
17	Hiple – Duck Lake	6/3/2030	$696
18	Oneida – Nelson Road	12/29/2029	$403
		Total Project Portfolio Cost	$10,324

The projected cost allocation for Duke Energy Indiana LRTP Tranche 1 projects is provided in Table I-5 below.

Table I-5: Projected Duke Energy Indiana MISO LRTP Tranche 1 Cost Allocation of $10.3B Estimated Gross Plan Additions

Year	Annual Revenue Requirement ($ Millions)	CIN Zone %	CIN Zone Allocation	Duke Energy Indiana %	Duke Energy Indiana Projected Annual Allocation
2025	$44.34	7.81%	$3.46	75.0%	$2.60
2026	$110.85	7.81%	$8.66	75.0%	$6.49
2027	$293.34	7.81%	$22.91	75.0%	$17.19
2028	$525.49	7.81%	$41.05	75.0%	$30.79
2029	$801.94	7.81%	$62.64	75.0%	$46.98
2030	$1,152.14	7.81%	$90.00	75.0%	$67.50
2031	$1,285.75	7.81%	$100.44	75.0%	$75.33
2032	$1,278.27	7.81%	$99.85	75.0%	$74.89
2033	$1,270.78	7.81%	$99.27	75.0%	$74.45
2034	$1,263.27	7.81%	$98.68	75.0%	$74.01

MISO complies with any applicable laws and regulations granting a right of first refusal to a Transmission Owner. The Transmission Owner will be assigned any transmission project within the scope, and in accordance with the terms, of any applicable laws and regulations granting such a right of first refusal. Indiana Code § 8-1-38-9 applies to transmission facilities approved for construction through MISO's planning process. The incumbent Transmission Owner must exercise the right of first refusal to construct and own such transmission facilities within 90 days of the transmission facilities being approved for construction. Thus, Duke Energy Indiana and other Indiana utilities will have this right of first refusal to construct and own some of the LRTP Tranche 2.1 projects.

The ongoing LRTP studies and analysis will provide guidance on additional long-term transmission planning needed to ensure a reliable system as MISO and the Duke Energy Indiana systems experience increased penetration of renewable generation and decline in traditional dispatchable generating resources. Duke Energy Indiana remains fully engaged in MISO stakeholder processes on these critical issues.

J

Appendix J: Environmental Compliance

Environmental regulations are changing at a rapid pace as the country undertakes an energy transition. Duke Energy Indiana's 2024 Integrated Resource Plan ("IRP" or the "Plan") has considered compliance costs with existing rules and regulations as part of the planning process, as well as potential future regulatory actions that should also be considered when making long-term decisions regarding the generation portfolio. Looking at the actual and potential impacts holistically will ensure Duke Energy Indiana (the "Company") can meet future resource needs and environmental requirements in a reliable and economic manner.

Environmental regulations that are not likely to impact decisions regarding future generation strategies have not been included in this summary. Compliance with these regulations is generally considered to be a "cost of conducting business." This primarily includes regulations related to natural resources. Duke Energy Indiana tracks developments in these regulations and implements procedural changes as necessary to ensure compliance.

This Appendix is organized first with a discussion of existing laws and regulations followed by risks associated with anticipated and potential changes to environmental regulations, and how the environmental regulations were included in IRP modeling.

Existing Laws & Regulations - Air

Ozone National Ambient Air Quality Standards

Background

The Clean Air Act ("CAA") directs the U.S. Environmental Protection Agency ("EPA") to develop National Ambient Air Quality Standards ("NAAQS") for six criteria compounds. The criteria compounds include carbon monoxide (CO), particulate matter (PM), nitrogen dioxide (NO_2), lead (Pb), Ozone (O_3), and sulfur dioxide (SO_2). There are two NAAQS standards for each compound, primary standards, which protect human health, including sensitive populations such as children and asthmatics, and secondary standards, which protect public welfare, such as visibility and agriculture. The standards are periodically reviewed to ensure they reflect the latest science and are adequately protective. They include both a numerical limit, as well as applicable averaging periods. Areas that meet the NAAQS are termed "attainment" areas, and those not meeting the standards are "nonattainment" areas. States are required to submit State Implementation Plans (“SIPs”) that outline measures to be implemented that will allow nonattainment areas to come into compliance.

Regulatory History

The ozone standard has been reviewed periodically, and the existing primary and secondary standards, established in 2015, are 0.070 parts per million (“ppm”), as the fourth-highest daily maximum eight-hour concentration, averaged across three consecutive years. The EPA finalized Indiana attainment designations in 2017, based on actual 2014-2016 ozone air quality data. The EPA designated two Indiana counties as nonattainment, Lake and Porter counties (Chicago area). Areas in these counties are classified as “moderate” nonattainment, which requires Indiana to adopt additional emission controls at facilities in the affected townships. An attainment demonstration will be submitted by Indiana at the end of 2024 for these areas. There are no active Duke Energy Indiana generating facilities in the affected areas.

On December 31, 2020, the EPA completed its mandatory five-year NAAQS review and announced that it would retain the current 0.070 ppm standard. However, pursuant to Executive Order 13990 issued on October 29, 2021, the EPA was directed to reconsider the 2020 decision. In April 2022, the EPA published a draft Policy Assessment that recommended retaining the current ozone NAAQS. The Clean Air Scientific Advisory Committee (“CASAC”) provided extensive comments (June 9, 2023) to the EPA on the Policy Assessment. In response to CASAC, the EPA Administrator published a letter (August 18, 2023) responding to the CASAC comments and announcing that the EPA will begin its next statutory review of the ozone NAAQS and include the reconsideration process for the 2020 ozone NAAQS as part of this review. The Administrator stated that the updated review would be completed “as expeditiously as possible.”

On August 25, 2023, the EPA published a Call for Information in the Federal Register to initiate the new review. After the EPA’s August 2023 announcement that they would begin the five-year review process and reconsider the standard in accordance with the feedback from CASAC, the EPA filed an unopposed motion for voluntary remand of the 2020 actions. Therefore, the 2015 primary and secondary ozone standards remain in effect at 0.070 ppm.

Impacts to Duke Energy Indiana

At this time, it is not possible to predict the outcome of the ongoing ozone NAAQS review efforts and any resulting implications to Duke Energy Indiana operations. Duke Energy Indiana has open dialogue with regulators at both the state and federal levels to stay abreast of the latest developments. Once a final standard is promulgated, Duke Energy Indiana will actively engage with State regulators to support the development of the SIP.

Interstate Transport of Ozone

Background

In addition to requiring states to develop regulations to assure attainment of the NAAQS within their own statistical borders, the CAA also requires that the states develop plans to identify and reduce any significant impact that they may have on nonattainment areas in downwind states.

It is important to note that ground-level ozone is considered a "secondary pollutant," because it is not emitted directly from mobile or point sources of emissions. Ozone forms when there are precursor emissions, such as oxides of nitrogen ("NOx") and volatile organic compounds ("VOCs") that combine in the presence of heat and sunlight.

In February 2022, the EPA proposed the Good Neighbor Plan for the 2015 Ozone NAAQS to reduce NOx emissions during ozone season. These ozone season requirements were proposed as a Federal Implementation Plan ("FIP") by the EPA in response to findings that states within a 23-State region had not adopted adequate SIPs to address significant impacts on downwind nonattainment areas. Indiana filed a Good Neighbor SIP in 2018, which concluded that emission sources (including electric generating units ("EGUs")) within Indiana do not have a significant impact on downwind nonattainment areas.

In February 2023, the EPA disapproved 19 states' SIPs, including Indiana's submittal, and imposed a final FIP (the "Good Neighbor" Plan). The FIP places restrictions on banking and usage of allowances and establishes additional requirements that will reduce allowance allocations over time. These restrictions on allowance banking started with the 2023 ozone season. The 2024 ozone season has a new set of requirements, including a 0.14 lb NOx/MMBtu back-stop limit for units with a selective catalytic reduction ("SCR") system for control of NOx emissions. The EPA will also implement Dynamic State Emission Budgets for allowance distribution in 2026.

Impacts to Duke Energy

The NOx emission allowance program, along with the additional FIP restrictions, can impact compliance strategies and ultimately how generating units are dispatched. The projected allowance market price is a basis against which the costs of compliance are compared to determine the most economic options. The ozone season NOx allowance market can be a significant driver in compliance planning due to the additional limitations on NOx budgets resulting from the Good Neighbor Plan (refer to allowance prices from 2022). Table J-1 below shows the base number of seasonal NOx allowances allotted by the EPA for affected units on the Duke Energy Indiana system for the Cross State Air Pollution Rule 2022 - 2025 control periods.

Table J-1: Seasonal NOx Allowances

Station	Unit	% Ownership	2022	2023	2024	2025
Cayuga	1	100	541	422	415	415
	2	100	558	415	409	409
Edwardsport	1	100	171	187	185	185
	2	100	184	188	185	185
R Gallagher	2	100	56	0	0	0
	4	100	53	0	0	0
Gibson	1	100	635	465	458	458
	2	100	596	448	441	441
	3	100	666	478	471	471
	4	100	588	453	447	447
	5	50.05	558	414	408	408
Henry County Gen Station	1	100	19	15	15	15
	2	100	20	16	16	16
	3	100	20	16	16	16
Noblesville Repowering	1-3	100	33	37	37	37
Duke Energy Vermillion, II LLC	1	62.5	5	5	5	5
	2	62.5	4	4	4	4
	3	62.5	4	4	4	4
	4	62.5	4	4	4	4
	5	62.5	4	4	4	4
	6	62.5	5	5	5	5
	7	62.5	4	4	4	4
	8	62.5	3	4	4	4
Wheatland Gen Facility LLC	1	100	18	14	14	14
	2	100	17	14	13	13
	3	100	13	12	11	11
	4	100	13	11	11	11

The cost of NOx ozone season allowances in addition to the variable cost of control is an important factor that can impact short-term decisions relative to dispatch, operating, and maintenance costs. Forecast allowance prices will also impact longer-term dispatch strategies. Duke Energy Indiana manages emissions risk by utilizing a mixture of purchasing and selling allowances, installing equipment, and, when applicable, purchasing power. The most economic decision is dependent upon the current and forecasted market price of allowances, the cost and lead time to install control equipment, and the current and forecasted market price of power. These factors are reviewed as markets change, and the most economic emission compliance strategy is employed.

Duke Energy Indiana has ensured compliance with the allowance-based requirements of the Good Neighbor Plan by maintaining an interdepartmental group to perform NOx emission allowance management. This group monitors the emissions reductions achieved through enhanced performance of the SCR systems installed at Edwardsport, Cayuga, and Gibson stations. Similar approaches are applied for the management of all emission allowances under other regulatory programs (i.e., acid rain).

Legal Challenges

As mentioned previously, many of the recent regulatory changes have the potential to alter the operation of the electric grid. As such, multiple groups have initiated legal challenges to many of the regulations that will be discussed in this document.

Challenges to the disapproval of the SIP submittals have been filed in the Fourth, Fifth, Sixth, Eighth, Ninth, Tenth, and Eleventh D.C. Circuits. Petitioners include both states and industry groups. There are open questions as to whether these challenges should be heard by the regional circuit courts or consolidated and heard by the D.C. Circuit. Some regional circuit courts have granted stays with respect to the final SIP disapprovals (does not include Indiana) while the courts decide the proper venue for the various cases.

Challenges to the EPA's Final FIP have been filed in the Fifth, Sixth, Seventh, Eighth, Ninth, Tenth, Eleventh, and D.C. Circuits. Petitioners include both states and industry groups, challenging the Final FIP more generally, as well as application of the FIP to specific states, including Indiana. On June 27, 2024, the U.S. Supreme Court, in a 5-4 decision, issued an order granting emergency applications filed by state and industry petitioners to stay the EPA's Final FIP. The Supreme Court's order stays enforcement of the Final FIP pending the D.C. Circuit's review and any petition for writ of certiorari. It is expected that a decision on the pending actions is likely in 2025.

On August 5, 2024, the EPA filed in the D.C. Circuit a motion for partial voluntary remand of its FIP. The EPA is requesting that the D.C. Circuit partially remand the Good Neighbor FIP so that the Agency can take "supplemental final action" to address the "record deficiency" identified by the Supreme Court in its stay decision. According to the EPA, the Supreme Court found that the Good Neighbor FIP may be "procedurally defective" due to the EPA's failure to adequately respond to certain comments. The EPA explains that it intends to supplement its response to comments on the severability of the Good Neighbor FIP, and anticipates completing this review by November 30, 2024, without soliciting further notice and comment on its supplemental action. State and industry petitioners oppose the EPA's request and argue that rather than remand the rule as the EPA is seeking, the D.C. Circuit should vacate it. On September 12, 2024, the D.C. Circuit granted this motion, remanding the administrative record to the EPA for further consideration of comments related to severability.

Given multiple legal challenges to the regulation, it is difficult to predict where and when these actions may ultimately conclude. Duke Energy Indiana continues to track developments and ensure that the latest information is communicated to internal groups managing daily operations, as well as those forecasting operations longer-term.

Particulate National Ambient Air Quality Standards

Background

As described earlier in this document, the EPA is directed to establish NAAQS for criteria compounds, including particulate matter. Particulates are regulated based on the size of the particle. Specifically, fine particulate matter is defined as particles that are 2.5 microns or less in diameter ($PM_{2.5}$) or particulates that are 10 microns or less in diameter (PM_{10}).

Regulatory History

Section 109(d) of the CAA requires the EPA to review and, if necessary, revise the NAAQS every five years. Prior to the 2024 changes discussed below, the EPA last revised the PM NAAQS in January 2013. Table J-2 below outlines the particulate NAAQS that were established in 2013.

Table J-2: Current Particulate National Ambient Air Quality Standards

Compound	Primary or Secondary Standard	Averaging Period	Standard	Form of the Standard
PM_{10}	Primary and Secondary	24 hour	150 mg/m^3	Not to be exceeded more than once per year on average over three years
$PM_{2.5}$	Primary	1 year	12 mg/m^3	Annual mean, averaged over three years
	Secondary	1 year	15 mg/m^3	
	Primary and Secondary	24 hour	35 mg/m^3	98th percentile, averaged over three years

Note: ("PM") represents Particulate Matter, measured in milligrams per cubic meter ("mg/m^3").

In December 2020, the EPA published a final rule that retained the 2013 particulate NAAQS without revision. However, the EPA announced in June 2021 that the Agency would reconsider the December 2020 decision "because available scientific evidence and technical information indicate that the current standards may not be adequate to protect public health and welfare, as required by the Clean Air Act." To support the reconsideration review, the EPA released a Supplemental Integrated Science Assessment and updated its Policy Assessment from the 2020 PM NAAQS review in May 2022.

On February 7, 2024, the EPA published a final rule resulting from the reconsideration of the particulate NAAQS. The final rule lowered the primary annual $PM_{2.5}$ NAAQS from 12.0 μg/m^3 to 9.0 μg/m^3 to reflect new science regarding particulate pollution. The final rule retains the remaining particulate standards at their current levels. Within two years after setting a new NAAQS or revising an existing standard, the EPA must designate (using information submitted in the SIP), based on the most recent set of air monitoring or modeling data, areas as meeting (attainment areas) or not meeting (nonattainment areas), the standards. For an area in moderate nonattainment, the SIP must provide for attainment as expeditiously as practicable but no later than the end of the sixth calendar year after nonattainment designations. Thus, according to the EPA, 2032 is "likely the earliest possible year that states would need to demonstrate attainment of the standards."

Impacts to Duke Energy Indiana

The promulgation of a NAAQS does not automatically result in emission limits or other control measures applicable to an emission source. Instead, the NAAQS create an obligation for states and the EPA to develop lists of "nonattainment" areas where the $PM_{2.5}$ concentration in the air exceeds the new standards, then states develop (and the EPA approves) a SIP that contains requirements necessary to achieve and maintain the NAAQS.

For Duke Energy Indiana, the most likely impact of the more stringent PM NAAQS would be increased permitting requirements for projects that are located in a nonattainment area. Under the CAA, a new major source of air pollutants or a major modification to an existing source must obtain preconstruction permits that demonstrate through air quality modeling that the source will not cause or contribute to a NAAQS violation.

Legal Challenges

A coalition of 24 states immediately filed a challenge to the final rule in the D.C. Circuit. Four petitions for review of the final rule were ultimately filed prior to the procedural deadlines. On April 5, 2024, a second coalition of states filed a motion to intervene on behalf of the EPA, other motions in support of the EPA were also filed by various environmental and health organizations. As of the date of this document, the potential outcome from the legal challenges is unknown. As mentioned earlier, Duke Energy Indiana tracks legal and regulatory developments closely and will continue to monitor the status of this regulation.

Mercury & Air Toxics Standards

Background

One of the most extensive revisions in the Clean Air Act Amendments of 1990 addressed the Air Toxics Program. Specifically, the EPA was directed to identify categories of major sources that emit any of the 188 hazardous air pollutants ("HAP") and then develop regulations to minimize emissions (National Emission Standards for Hazardous Air Pollutants ("NESHAP")). A major source of air toxics is one that emits more than 10 tons per year of a single HAP compound or 25 tons per year of any combination of compounds.

Hazardous air pollutant emissions from coal-fired electric utility steam generating units are regulated under the Mercury and Air Toxics Standards (“MATS”) published at 40 CFR part 63, subpart UUUUU. The MATS rule was promulgated on February 16, 2012, and became effective April 16, 2012. Compliance with the regulation was required by April 16, 2015 (unless a facility requested a one-year extension). In general, the regulation outlines numerical emission limits and work practice standard requirements for affected units. All existing and new coal-fired EGUs must achieve numerical emission limits for mercury (Hg), filterable PM (a surrogate for non-mercury HAP metals), and hydrochloric acid or sulfur dioxide (HCl or SO_2, a surrogate for acid gases). Work Practice Standards are used to ensure reductions in organic HAP emissions.

Regulatory History

Since the 2015 compliance date, the MATS regulation has been modified multiple times to incorporate minor revisions, mostly related to electronic reporting obligations and to correct typographical errors.

Under Section 112 of the CAA, the EPA must evaluate NESHAP standards after eight years to address any residual risks posed by the source category (called the “residual risk review”). Additionally, Section 112 requires the EPA, at least every eight years on an ongoing basis, to review and revise as necessary the NESHAP standard taking into account developments in practices, processes and control technologies (called the “technology review”).

In 2020, the EPA conducted the eight-year residual risk and technology review and determined that the standard was protective of human health and technology had not advanced to warrant updates to the standard. With the change in administration in 2020, the EPA was directed to review this decision through Executive Order 13990. The EPA issued a proposed rule to revise the MATS regulation on April 24, 2023.

On April 25, 2024, the EPA released a final regulation that details the EPA’s conclusions regarding the reconsideration of the risk and technology review for the MATS standard. The EPA determined that the 2020 technology review was flawed and that developments in control technologies require changes to the filterable particulate matter standard (along with other revisions that are not applicable to Duke Energy Indiana). However, the EPA concluded that the residual risk review appropriately concluded that the existing NESHAP provides an ample margin of safety to protect public health.

Existing coal-fired EGUs can demonstrate compliance with the emission limits for non-Hg metal HAP by complying with compound-specific standards, or by using filterable PM as a surrogate. All Duke Energy Indiana facilities comply with the regulation by using the filterable PM surrogate. The final rule retains these compliance options for EGUs but lowers each of the associated emission limits. The EPA finalized a filterable PM emission standard of 0.010 lb/MMBtu, averaged on a 30-day rolling basis (lowered from 0.030 lb/MMBtu). Affected EGUs must demonstrate compliance with these updated limits within three years of the effective date of the final rule. The rule was published in the Federal Register on May 7, 2024; therefore, compliance with the reduced filterable PM standard is required by July 8, 2027.

Impacts to Duke Energy Indiana

Duke Energy Indiana will ensure compliance with the revised standard prior to July 8, 2027. To ensure the affected generating units (Cayuga and Gibson) can reliably meet the lower filterable particulate standard, the Company is evaluating capital projects that will be required on the electrostatic precipitators and flue gas desulfurization ("FGD") units. The projects will be scoped according to existing processes and integrated into outages prior to the compliance date. Alternative compliance strategies, such as facility wide emissions averaging, will also be considered. Any ancillary changes (alarms, control room graphics, etc.) will also be identified and completed prior to July 2027.

Initial cost estimates for control equipment upgrades have been included in the IRP modeling efforts to ensure that compliance with the MATS regulation is factored into long-term planning decisions.

Legal Challenges

The deadline for filing petitions for review of the final rule was July 8, 2024. Several parties have filed petitions for review in the D.C. Circuit, including 23 states (including Indiana), various power companies, and industry groups. In addition, several states and environmental groups have intervened in support of the EPA. Briefings and oral arguments would likely occur in 2025 with a potential decision in late 2025 or early 2026.

Additionally, multiple groups of petitioners filed motions to stay the final rule, which were denied by the D.C. Circuit on August 6, 2024. On August 16, 2024, a coalition of state petitioners and an industry petitioner filed emergency stay applications in the U.S. Supreme Court after the D.C. Circuit denied their motions to stay the EPA's final rule revising the MATS. On September 13, 2024, the EPA filed its consolidated response to the emergency stay applications filed with the Supreme Court. On October 4, 2024, the U.S. Supreme Court denied emergency applications to stay the final MATS rule.

As described in this Appendix, 2024 has been an active year for new regulatory developments from the EPA and in most cases, intervenors have submitted legal challenges to each regulation. This Appendix outlines the latest status of the legal challenges, it is difficult to predict the timeline for additional court decisions and what those outcomes may be.

Greenhouse Gas Regulations

Background

In 2007, the U.S. Supreme Court ruled in Massachusetts v. EPA[1] that greenhouse gases (e.g., carbon dioxide (CO_2)) are a pollutant subject to regulation under the CAA. Subsequently, the EPA has undertaken a number of rulemakings targeting greenhouse gas emissions from EGUs.

[1] Massachusetts v. Environmental Protection Agency, 549 U.S. 497 (2007).

Regulatory History

Most recently, on May 11, 2023, the EPA issued proposed CAA emission limits and guidelines for CO_2 emissions from new and existing fossil fuel-fired power plants based on what the EPA considered to be cost-effective and available control technologies. The Environmental Protection Agency Clean Air Act Section 111 May 2024 Final Rule ("EPA CAA Section 111 Rule") directs the EPA to use different approaches for new and existing sources of GHG emissions. For new sources of GHG emissions, CAA 111(b) requires the EPA to set federal standards for new, modified, and reconstructed sources. For existing sources, under CAA 111(d), states submit plans for existing sources containing standards consistent with federal emission guidelines.

On May 9, 2024, the EPA published New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; and Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units as final rules, which include requirements under Section 111(b) for new combustion turbines, and under Section 111(d) for existing coal-fired EGUs.

Impacts to Duke Energy Indiana

In its final Section 111(d) rule, the EPA established two subcategories for coal-fired units and a retirement option. Table J-3 below summarizes these subcategories.

Table J-3: Summary of Clean Air Act 111 Subcategories

Coal			New Natural Gas		
Option 1 Retire by December 31, 2031	**Option 2 (Medium-Term Units)** 40% natural gas co-fire by 12/31/30; retire by 12/31/38[1]	**Option 3 (Long-Term Units)** Install carbon capture and sequestration by 1/1/32; continue operations indefinitely	**Baseload** (>40% capacity factor) 90% CCS operation by 2032	**Intermediate load** (20-40% capacity factor) CO_2 intensity restrictions	**Low load natural gas** (<20% capacity factor) Low intensity natural gas

Note 1: If coal is converting to 100% natural gas and intends to run past 2039, it must be converted to natural gas steam unit and be off coal by January 1, 2030.

- **For Long-Term Coal-Fired Steam Generating Units**: Units must install and operate a carbon capture and sequestration ("CCS") system beginning in 2032 with 88.4% reduction from baseline emissions. Units meeting the 88.4% reduction in emissions may continue to operate indefinitely.

- **Medium-Term Coal-Fired Steam Generating Units**: These are units that elect to cease operations before January 1, 2039, and by January 1, 2030, co-fire 40% natural gas that results in a 16% reduction in emission rate compared to their baseline emissions.

- **Applicability Exemption**: Units that elect to cease operations prior to January 1, 2032, have no further obligations to comply with the regulations.

In addition, if a coal unit converts to firing 100% natural gas and intends to run past 2039, it must convert prior to January 1, 2030. These new requirements will impact generating units in Indiana, and compliance with the standards detailed above will be implemented as part of a state plan submitted to the EPA for approval.

Duke Energy Indiana continues to evaluate the impacts of this regulation and evaluate the compliance options that are available to the utility as part of this 2024 IRP. Concurrent with internal evaluations, personnel are engaging with state regulators to participate in the state rulemaking process as the Indiana Department of Environmental Management ("IDEM") develops its state plan.

Legal Challenges

Ongoing and anticipated court actions will be important as plans are developed (both internal to Duke Energy Indiana and state plans). As of the writing of this document, the final regulation is subject to multiple challenges pending in the D.C. Circuit. The lead case is West Virginia v. EPA, No. 24-1120. The deadline for filing petitions for review of the final rules was July 8, 2024. Several parties, including 27 states (including Indiana), various power companies, and industry groups filed petitions in the D.C. Circuit. In addition, several states, environmental groups, and power companies intervened in support of the EPA. On September 6, 2024, petitioners filed their opening merits brief that focused on six key challenges of the regulation.

In May 2024, multiple petitioners filed motions to stay the final rules, which were consolidated and subsequently denied by the D.C. Circuit on July 19, 2024, which found that the petitioners had not satisfied the "stringent requirements" for a stay. Following this action, on July 23, 2024, eight state and industry petitioners filed emergency stay applications in the U.S. Supreme Court. The petitioners requested that the Supreme Court stay the final rules as a whole, pending resolution of the underlying litigation in the D.C. Circuit. On October 16, 2024, the U.S. Supreme Court denied the emergency stay applications. The rules will remain in place as the D.C. Circuit considers the case on the merits.

Existing Laws & Regulations - Land

Coal Combustion Residuals

Background

The EPA signed the Disposal of Coal Combustion Residuals ("CCR") from Electric Utilities final rule on December 19, 2014, which was published in the *Federal Register* on April 17, 2015. The 2015 CCR rule established national minimum criteria consisting of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements, and post-closure care, and recordkeeping, notification, and internet posting requirements for existing and new CCR landfills and CCR surface impoundments under subtitle D of the Resource Conservation and Recovery Act.

Regulatory Changes

The recent Legacy CCR Surface Impoundments rule was published in the *Federal Register* on May 8, 2024, regulating CCR surface impoundments at retired facilities (legacy CCR surface impoundments) as well as previously unregulated areas of CCR on the land at regulated facilities, called CCR management units. These revisions to the 2015 CCR rule were in response to a D.C. Circuit court decision, which held that it was incorrect for the EPA to have excluded legacy CCR surface impoundments from the scope of the 2015 CCR rule. Accordingly, with the exception of the 2015 CCR rule's location standards and liner design requirements, the legacy CCR surface impoundments rule subjects legacy impoundments to a full suite of regulatory requirements currently applicable to inactive CCR surface impoundments at active power plants, including the rule's groundwater monitoring, corrective action, closure, and post-closure care requirements. In addition, the Legacy CCR surface impoundments rule imposes a subset of the 2015 CCR rule's requirements on any area of land on which any noncontainerized accumulation of CCR is received, is placed, or is otherwise managed, that is not a regulated CCR unit. Owners/operators of all active facilities and any inactive facilities with a legacy impoundment are required to undertake a facility evaluation to identify CCR management units containing 1 ton or more of CCR. Any CCR management units that contain CCR in amounts equal to or greater than 1,000 tons are subject to the CCR rule's groundwater monitoring, corrective action, closure, and post-closure care requirements.

The EPA also finalized changes to the closure-in-place performance standard, adding a new definition of "infiltration" to include horizontal movement of groundwater through the unit and revising the closure performance standard to require the elimination of free liquids before placement of the final cover system.

Impacts to Duke Energy Indiana

Duke Energy Indiana has made significant progress closing CCR impoundments at its generating facilities in compliance with the federal CCR rule and Indiana solid waste regulations. IDEM has approved closure plans for each of Duke Energy Indiana's CCR impoundments, with the plan for two impoundments at Gallagher Station being revised based on input from the EPA. Closure work has been completed at nine of 22 impoundments, with closure work underway at almost all of the remaining 13 impoundments.

Duke Energy Indiana does not have any legacy CCR surface impoundments as defined by the new rule and so is not affected by this portion of the Legacy CCR Surface Impoundments rule. However, the Company will be required to conduct facility evaluations at all active facilities to identify any accumulations of CCR on the land greater than 1 ton (i.e., CCR management units).

The full impact of these changes has not yet been determined, but it is not expected to affect the impacted facilities' electric generating operations and, therefore, has not influenced modeling forecasting future generation mix. However, additional investigation work, groundwater monitoring and potential remediation, closure work, and coordination with state regulators to potentially modify closure plans will be required.

Legal Challenges

On June 13, 2024, the first challenge to the Legacy CCR Surface Impoundments rule was filed by City Utilities of Springfield in the D.C. Circuit. Subsequently, on August 6, 2024, Duke Energy Carolinas, Inc., Duke Energy Progress, Inc., and Duke Energy Indiana, LLC filed a petition for review as part of a group of similarly affected electric utilities. In addition, Duke Energy Indiana, LLC is challenging the rule as a member of a utility trade group, which also filed a petition for review. A group of 17 states also filed a challenge to the rule prior to the August 6, 2024, deadline. These cases have been consolidated, with the lead case being City Utilities of Springfield v. EPA, No. 24-1200.

Existing Laws & Regulations - Water

Section 316(a) & 316(b) of the Clean Water Act

Background – 316(a)

Section 316(a) of the Clean Water Act ("CWA") applies to point sources that discharge heat in their effluent. The permitting authority is authorized to impose alternative limitations to control the thermal discharge in lieu of the limits that would otherwise be applied under sections 301 or 306 of the CWA. The regulations that implement section 316(a) are codified at 40 CFR part 125, subpart H.

These regulations outline the criteria and process for evaluating if an alternative effluent temperature limit (i.e., a thermal variance from the otherwise applicable effluent limit) can be included in a permit. Prior to a thermal variance being approved, 40 CFR sections 125.72 and 125.73 require the facility to demonstrate that the otherwise applicable temperature limit is more stringent than necessary to assure the protection and propagation of the waterbody's balanced, indigenous population of shellfish, fish, and wildlife.

Thermal discharges from facilities are regulated by Indiana Water Quality Standards with any compliance requirements provided in the facility National Pollutant Discharge Elimination System ("NPDES") operating permit issued by IDEM.

Impacts to Duke Energy Indiana – Section 316(a)

- **Cayuga**: Cooling towers are utilized as necessary to attenuate the thermal discharge at this facility. This facility also has a thermal variance, which must be justified with each NPDES operating permit renewal. Routine maintenance of the cooling towers is necessary to ensure operability for compliance with the NPDES permit. At this time, the Cayuga cooling towers are approaching the end of their expected life, and extensive refurbishment or replacement will potentially be necessary within the next five years. The models included an option to replace the cooling towers, which would address end-of-life concerns for the existing equipment and would also ensure compliance with 316(b) provisions discussed below. New generation to replace existing coal-fired units would also be considered as part of the refurbishment or replacement evaluation.

Justification to continue the facility thermal variance was submitted to IDEM with the NPDES operating permit renewal application. IDEM is evaluating the thermal variance information; however, the outcome of this review is currently undetermined.

- **Gibson**: Closed-cycle cooling (using a cooling pond) is utilized at this facility; therefore, there are no thermal discharge compliance concerns, and none are foreseen for the site.

- **Noblesville**: Closed-cycle cooling (using mechanical draft cooling towers) is employed at this combined-cycle facility; therefore, there are no thermal discharge compliance concerns, and none are foreseen for the remaining life of the facility. Note that maintenance is periodically performed to ensure proper operation of the cooling towers. During the most recent maintenance evolution, a high-level review of the structure was conducted, and no significant findings were identified. For modeling purposes, it has been assumed that significant upgrades or rebuilds are not required for the Noblesville cooling towers through the current planned retirement date.

Background – Section 316(b)

Cooling water intake structures may contribute to environmental impacts by entraining fish and shellfish or their eggs in the cooling system. These organisms may be impacted by heat, physical stress, or other processes within the cooling system. Larger organisms can be impacted if they are trapped against screens at the front of an intake structure. Section 316(b) of the CWA directs the EPA to assure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

The EPA issued regulations to address cooling water intake structure compliance during 2014 (the “316(b) rule”). A cooling water intake structure is subject to the 316(b) rule if the design flow is at least 2 million gallons per day (MGD) and 25% or more of the water withdrawn is used for cooling purposes.

The 316(b) rule requires IDEM and other agencies to determine if any modifications to the existing cooling water intake structure are necessary to address compliance with entrainment and impingement of organisms in the source water body. This determination occurs with each NPDES operating permit renewal.

Impacts to Duke Energy Indiana – Section 316(b)

- **Cayuga**: Comprehensive study reports were submitted in 2020 to IDEM as required by the facility NPDES operating permit. IDEM and other agencies are reviewing the study reports; however, the outcome of this review is currently undetermined. New generation to replace the existing units would also be a consideration for the IDEM review process. As mentioned above, the models included an option to replace the current cooling towers, which would ensure that the Cayuga facility is compliant with 316(a) and 316(b) requirements.

- **Gibson**: Study reports were submitted in 2024 to IDEM as required by the 316(b) rule. IDEM and other agencies will review the study reports; however, as the facility already minimizes surface water withdrawal for the closed-cycle cooling pond, no compliance costs are foreseen.

- **Noblesville**: Study reports were submitted in 2022 to IDEM as required by the 316(b) rule. Closed-cycle cooling using mechanical draft cooling towers are used at this facility to minimize any entrainment or impingement of organisms in the source waterbody. IDEM and other agencies determined in the latest NPDES operating permit that the facility currently maintains is compliant with the 316(b) rule, and no additional technologies or operational measures are necessary.

Steam Effluent Guidelines

Background

The CWA authorizes the EPA to establish nationally applicable, technology-based Effluent Limitation Guidelines ("ELGs") for discharges from different categories of point sources, such as industrial, commercial, and public sources, for wastewater discharged to surface waters and municipal sewage treatment plants. The EPA issues these regulations for industrial categories based on the performance of treatment and control technologies. The limitations are incorporated into a station's NPDES permit issuance or renewal.

Regulatory History

On September 30, 2015, the EPA promulgated a rule revising the ELGs for the Steam Electric Power Generating point source category (the "2015 rule"). The 2015 rule addressed effluent limitations and standards for multiple waste streams generated by new and existing steam electric facilities: bottom ash transport water ("BATW"), combustion residual leachate ("CRL"), FGD wastewater, flue gas mercury control (FGMC) wastewater, fly ash transport water, gasification wastewater, and legacy wastewater. Challenges to the 2015 rule were filed and ultimately consolidated in the Fifth Circuit Court of Appeals. At the request of the EPA, the Fifth Circuit granted the request to sever and hold in abeyance claims related to 2015 rule limitations for FGD wastewater and BATW. With respect to claims related to limitations applicable to legacy wastewater and CRL, the Fifth Circuit issued a decision on April 12, 2019, vacating those limitations.

On August 31, 2020, the EPA promulgated the Steam Electric Reconsideration Rule (the "2020 rule"). The 2020 rule revised the 2015 rule requirements related to FGD wastewater and BATW at existing sources. The 2020 rule also established a subcategory for units that cease combustion of coal and for units that voluntarily meet more stringent limits under a voluntary incentives program (VIP) by December 31, 2028.

On May 9, 2024, the EPA published the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (the "2024 rule"). The rule establishes a no discharge limit for FGD wastewater, BATW, and CRL at sites combusting coal to be met by a date that is as soon as possible beginning July 8, 2024, but no later than December 31, 2029. Numeric limits for CRL at sites that no longer combust coal were included in the rule to be met no sooner than 120 days after combustion of coal ceases and no later than April 30, 2035. The rule also establishes numeric limits for unmanaged CRL – defined as discharges via groundwater to surface water that are functionally equivalent to a surface water discharge or CRL that mixes with groundwater and is pumped to the surface for discharge – that must be met by a date that is as soon as possible beginning July 8, 2024, but no later than December 31, 2029.

The 2024 rule retained the subcategory in the 2020 rule for units that cease combustion of coal by December 31, 2028, and retained the provision allowing these units to transfer from the cease combustion of coal subcategory to the VIP with a notice to be submitted by December 31, 2025. The 2024 rule established a new subcategory for units that cease combustion of coal by December 31, 2034. Under this new subcategory, units must submit a "Notice of Planned Participation" and meet the limitations in the 2020 rule by December 31, 2025.

Impacts to Duke Energy Indiana

- **Cayuga**: Duke Energy Indiana submitted the "Notice of Planned Participation" to opt in to the cease combustion of coal by December 31, 2028, subcategory under the 2020 rule. The station can transfer to the VIP and meet those limits by December 31, 2028. The decision to transfer into the VIP must be made by December 31, 2025, by submitting an updated NOPP to IDEM. Prior to making such an update to the compliance approach, Duke Energy Indiana would engage with IDEM to discuss the drivers impacting the station's ability to retire the units by December 31, 2028, and planned projects to ensure that the station meets the VIP limits.

- **Gibson**: The Gibson Generating Station does not discharge FGD wastewater, BATW, CRL, or unmanaged CRL to surface waters subject to the CWA. As such, the station is not impacted by this rule.

- **Gallagher**: Gallagher Generating Station has ceased the combustion of coal; therefore, the station is not subject to the no discharge limitations for FGD wastewater, BATW, and CRL at stations combusting coal. CRL and possibly unmanaged CRL are generated and discharged at the station, and the numeric limits established under the 2024 rule for these waste streams will apply. Evaluations are being conducted to determine if additional treatment will be needed.

- **Noblesville**: The Noblesville Generating Station has ceased the combustion of coal; therefore, the station is not subject to the no discharge limitations for FGD wastewater, BATW, and CRL at stations combusting coal. Unmanaged CRL may be generated and discharged at the station, and the numeric limits established under the 2024 rule for this waste stream will apply. Evaluations are being conducted to determine if additional treatment will be needed.

Legal Challenges

Multiple challenges to the 2024 Rule have been filed by industry, states, and environmental groups. On June 14, 2024, the petitions were consolidated in the U.S. Court of Appeals for the Eighth Circuit. On July 26, 2024, various power industry and state petitioners (including Indiana) filed a motion for a stay of the final rule. In the July 26 motion for a stay, various power industry and state Petitioners argue that they are likely to succeed on the merits because the EPA (1) “arbitrarily sidestepped demonstrated errors in its cost-estimation methodology” and (2) “failed to adequately account for the substantial costs incurred in reliance on the 2020 Rule.” Similar to the updates provided previously, Duke Energy Indiana cannot predict the outcome of the pending court challenges, but monitors updates closely to ensure internal stakeholders have the latest information available to inform planning decisions.

Environmental Compliance Planning: Potential Laws & Regulations

Combustion Turbine Air Quality Rules

Background

The EPA has identified stationary combustion turbines as major sources of HAP emissions. The NESHAP for combustion turbines was promulgated at 40 CFR part 63, subpart YYYY in 2004. The regulation set emission standards for new turbines and provided for a number of subcategories. Shortly after promulgation, the EPA received a petition to “delist” several subcategories based on an assertion of limited risk from the sources. This included the lean premix combustion turbines firing natural gas with limited oil backup subcategory. Note that no standards were proposed for existing combustion turbines in the 2004 rule.

On April 7, 2004, the EPA proposed to delist lean premix natural gas-fired turbines as well as three additional subcategories of turbines. At the same time, the EPA proposed to stay the effectiveness of the NESHAP for the affected subcategories to ‘‘avoid wasteful and unwarranted expenditures on installation of emission controls, which will not be required if the subcategories are delisted.’’ The stay was finalized on August 18, 2004.

The proposal to delist the subcategories was never finalized in light of court decisions, which addressed limits on the EPA’s ability to delist subcategories. In the 2019 proposed Residual Risk and Technology review (“RTR”) for the Stationary Combustion Turbine NESHAP, the residual risk analysis did not support a conclusion that the entire Stationary Combustion Turbines source category met the criteria for delisting. Consequently, the EPA proposed to remove the stay of the standards for new lean premix and diffusion flame natural gas-fired turbines. However, when the RTR was finalized on March 9, 2020, the EPA did not finalize the removal of the stay to allow for additional time to review the public comments.

Concurrently, in August 2019, the EPA received a petition to delist the entire Stationary Combustion Turbines source category. While previous the EPA actions determined that leaving the stay in place while the delisting petitions were reviewed, the EPA concluded in 2022 that the new petition to delist the source category does not warrant any further delay in lifting the stay; additionally, the Agency questioned the basis for issuing the stay in 2004. On March 9, 2022, the stay was lifted.

On April 16, 2024, the EPA published a final action denying the August 2019 petition requesting the removal of the stationary combustion turbines source category.

While the emission standards are now in place for new or reconstructed lean premix natural gas-fired turbines, there are no Duke Energy Indiana generating units that meet this criterion.

Expected Next Steps

The RTR was completed in March 2020 and determined acceptable risk and no new technologies were identified. In May 2020, the EPA received a petition for reconsideration that addressed two aspects of the regulation.

- Failure to remove the stay on applicability to new units, which has been resolved as described above; and
- No standards for unregulated HAP in accordance with the Louisiana Environmental Action Network case.

The petition was granted in August 2020 but is currently held in abeyance. The EPA has reached out to industry to collect emissions data and is currently in the process of analyzing the limited data set and how it can inform a future rulemaking process.

Along with the development of a NESHAP that will encompass existing combustion turbines, it is expected that the EPA will promulgate a suite of regulations focused on existing combustion turbines that includes limitations on greenhouse gas emissions from existing turbines. On March 26, 2024, the EPA opened a non-regulatory docket and issued framing questions to gather input regarding regulation of the entire fleet of existing natural gas combustion turbines in the power sector.

Environmental Compliance Assumptions & Results

Environmental Modeling Assumptions

As discussed, 2024 has resulted in significant new regulatory requirements that were evaluated in the modeling analyses to ultimately select the Preferred Portfolio. Some regulatory developments (generally related to natural resource regulations) will not have significant costs to compliance and have not been included explicitly in this analysis. Other regulations, such as the MATS provisions, have a compliance date (2027) prior to the effective date of any retirement decisions. Therefore, these costs were included in the model, but they do not substantially impact the output.

Another environmental compliance cost that ultimately does not impact the future generation mix is any cost that is the result of complying with the recent Legacy CCR Surface Impoundments rule, as these are costs related to historical operational practices.

The current IRP modeling analysis has a particular focus on compliance with the 316(b) rule, ELG revisions and the new CAA 111 rule. Table J-4 below outlines the combination of station and compliance approaches that were considered in the model.

Table J-4: Summary of Modeled Compliance Approaches

Station/Unit	CAA 111	ELG	316(b)
Gibson	Retire Coal by 1/1/2032	N/A	N/A
	Natural Gas Co-firing by 1/1/2030		
	Natural Gas Conversion by 1/1/2030		
	Combined-Cycle Generation by 1/1/2032		
	Combination of Approaches		
Cayuga	Retire Coal by 1/1/2031	Wastewater Treatment Improvements for Coal Operations past 12/31/2028	N/A
	Retire Coal by 1/1/2032		Closed-Cycle Cooling
	Natural Gas Co-firing by 1/1/2030		
	Natural Gas Conversion by 1/1/2030		
	Combined-Cycle Generation by 1/1/2031	N/A	N/A
	Combined-Cycle Generation by 1/1/2032		
Edwardsport	Natural Gas Co-firing by 1/1/2030	N/A	N/A
	Natural Gas Conversion by 1/1/2030		
	Carbon Capture & Sequestration by 1/1/2032		
Noblesville	N/A (existing natural gas)	N/A	N/A

In addition to retrofit costs for existing assets, any new generation considered in the model included the following operating constraints (from Table J-3 above) for large baseload natural gas turbine units (defined by 40% or greater capacify factor and heat input of 2,000 MMBtu/hr):

- Install advanced class combined-cycle units to meet the requirements of Phase 1 of the CAA 111 rule:
  - Phase one emission limitation, effective upon initial operation, of 800 lb. CO_2/MWh (on a 12-month calendar year basis)

- Install CCS by January 1, 2032 to be able to operate at a capacity factor >40% to meet the requirements of Phase two of the CAA 111 rule:
    - Phase 2 emission limitation of 100 lb. CO_2/MWh (on a 12-month calendar year basis) based on 90% capture CCS technology.

Remaining modeling assumptions for the compliance analysis were reviewed and updated where necessary to coincide with the other assumptions used for the development of this 2024 IRP.

For this analysis, Duke Energy Indiana utilized a similar analytical modeling process to past compliance planning activities. Refer to Appendix C (Quantitative Analysis) for details on modeling. Forecasts used in planning included fuel price forecasts, the EnCompass model for forecasting future MISO power prices, and observable market curves and extrapolation for emission allowance prices. Given the limited number of environmental compliance projects remaining in the modeling, costs for those projects were entered by hand. The historically used in-house Engineering Environmental Compliance Planning and Screening Model has been retired.

Environmental Related Encompass Results

In addition to compliance with CAA Section 111 final rule, the modeled costs associated with the ELG revisions, and 316(a and b) rules were incorporated into the EnCompass model (refer to Appendix C). The costs associated with operations utilizing these emission controls were reflected in unit operating costs and considered in the integration step of this 2024 IRP in conjunction with energy efficiency and various supply-side alternatives. Modeling results can be found in Chapter 4 (Candidate Resource Portfolios) and Appendix C.

Appendix K: Community Impact

Highlights

- Duke Energy Indiana (the “Company”) is deeply committed to community engagement, demonstrated through its dedicated Government and Community Relations team and newly formed Infrastructure Engagement team. These teams work closely with local stakeholders, emphasizing transparency, feedback, and collaboration, particularly during significant projects and weather events.
- Duke Energy Indiana plays a significant role in fostering economic growth through initiatives such as the Site Readiness Program and workforce development grants. These programs have led to substantial job creation, capital investment, and the development of a skilled workforce, enhancing the state's economic vitality.
- Duke Energy Indiana supports low-income customers through various initiatives, including the Share the Light Fund, the Neighborhood Energy Saver Program, and partnerships with local nonprofits. These efforts provide financial assistance as well as energy efficiency and home safety upgrades to help vulnerable customers manage their energy needs more effectively.

Community Engagement & Partnerships

Duke Energy Indiana's commitment to community engagement spans over a century and is characterized by a strong tradition of giving back to the communities it serves. As part of this commitment, the Company supports local organizations with financial resources and employee time, helps attract economic growth and investment to the state, engages local and diverse suppliers, and considers how its operations affect communities.

The Company’s outreach to communities on infrastructure projects builds stronger relationships and understanding for key initiatives. The Company is committed to seeking feedback and input on its projects and adjusting and aligning efforts where possible to achieve the best outcomes for the communities it serves.

Community Ambassadors

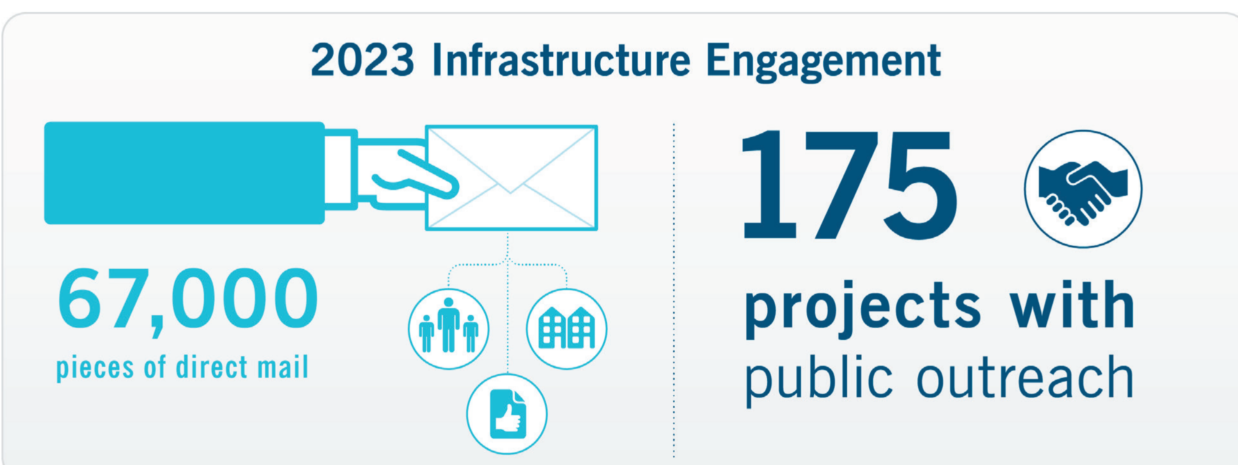
At the center of Duke Energy Indiana's community engagement is a dedicated and highly respected team of nine government and community relations managers in regions throughout the state. These managers work closely with customers, local officials, and community leaders in their areas, acting as local points of contact for communities. Never is that more important than during major storms when local managers are often the liaisons with community leaders and emergency responders. They are critical information sources for both the Company's response as well as the community's needs.

These individuals also address Company issues, concerns, and opportunities and coordinate local philanthropy and volunteer efforts that align with community objectives. In 2024, they served on 50 local boards, building long-term local relationships and serving as ambassadors for the Company and its customers.

Infrastructure Engagement Outreach

Duke Energy Indiana has a newly formed Infrastructure Engagement team focused on public engagement as the Company constructs new power generation, makes electric grid upgrades, and performs ongoing system maintenance with a goal of constructive outcomes for all stakeholders. The team connects with communities well before infrastructure project execution to solicit input and foster understanding of system needs. As seen in Figure K-1 below, in 2023, the Infrastructure Engagement team engaged in more than 175 projects. Thoughtful consideration of how significant projects, decisions, or transactions affect communities and stakeholders is a cornerstone of the Company's approach.

Figure K-1: 2023 Engagement by the Numbers



When siting new generation and infrastructure, the Infrastructure Engagement team interacts with communities during siting, construction, and early operations, employing a "listen, learn, and adjust" approach. This approach may include consultations with project site neighbors, phone and email surveys, project-specific webpages, direct mail communications, community open houses, and the creation of community advisory boards. In 2023, the team sent more than 67,000 pieces of direct mail communications to customers and project neighbors. The Duke Energy Indiana transmission team also held more than 25 meetings with stakeholders through open houses and homeowners' association, local government, and property owner meetings.

Duke Energy Indiana believes that being transparent about what it is trying to accomplish, seeking feedback and input, and adjusting plans where possible, will bring about the best outcomes for both the Company and the communities it serves.

Philanthropic Impact

Duke Energy Indiana is committed to creating a meaningful impact in its communities through corporate citizenship and community giving. Central to this effort is the Duke Energy Foundation, which provides shareholder-funded grants aimed at strengthening and uplifting communities throughout Indiana.

In 2023, the Duke Energy Foundation contributed $2.8 million in shareholder-funded grants to Indiana civic and community organizations. This philanthropic giving is centered on creating vibrant communities, furthering environmental initiatives, and assisting low-income residents. In one particularly successful program, the Duke Energy Foundation awarded $115,000 in statewide grants to assess and address childcare gaps in Indiana communities. Duke Energy Indiana joined with the Indiana Economic Development Association to launch a first-of-its-kind childcare innovation grants program to provide financial support to communities willing to approach this issue in new and innovative ways. Today, the grants are helping to address childcare gaps, a key workforce issue for Indiana working parents and their employers.

The Duke Energy Foundation also serves a unique role following natural disasters. In the spring of 2023, in response to severe storms and tornadoes that ripped across the Company's service territory, the Duke Energy Foundation targeted $145,000 in grants to local non-profit organizations that responded to severe damage across Sullivan, Johnson, Morgan, and Monroe counties. The grants were allocated to organizations such as the Red Cross, Salvation Army, and local community centers to support relief efforts including providing shelter, meals, basic supplies, and emergency management to those in need. With the Duke Energy Foundation's support, these organizations helped provide 12,879 meals and snacks and 876 cleanup kits for 680 individuals affected by the storms. Nearly 250 Hoosiers also received additional financial assistance to help with relocation expenses.

Duke Energy Indiana employees, as well as retirees, also give their time and personal resources to Hoosier communities. In 2023, they contributed nearly 13,600 volunteer hours and $416,000 to charitable organizations. The Company recognized their commitment in 2023 with matching funds of just over $474,000 to their chosen charities.

Economic & Workforce Development

Duke Energy Indiana's economic development efforts help to create jobs and attract capital investments that foster economic growth and community development. A dedicated team works with state and local leaders to attract new businesses to the state and help existing ones expand. Over the years, notable project accomplishments have included Meta in Jeffersonville, Ford Meter Box in Wabash, NOVAChem in Connersville, StarPlus Energy in Kokomo, and ENTEK in Terre Haute. As seen in Figure K-2 below, in 2023, the Company's cooperative efforts with state and local leaders helped attract more than 4,500 new jobs and over $6.4 billion in new capital investments to the state.

Figure K-2: 2023 Development and Investment

The Site Readiness Program is a strategic initiative that identifies, assesses, improves, and increases awareness of industrial sites within Duke Energy Indiana's service territory. The goal is to increase the competitiveness of industrial sites, attract new businesses, create jobs, and boost community tax revenue. Since the Site Readiness Program was launched in 2013, the Company has invested more than $1.3 million into 45 sites across its Indiana service territory. Stellantis and Samsung SDI selected one of those sites in Howard County for a new battery manufacturing facility, which they announced will create 2,800 jobs and $5.7 billion in capital investments.

Duke Energy Indiana also provides community partnership grants – including more than $126,000 to 23 communities in 2024 – that assist local and regional organizations with funding to market and promote their areas. These grants focus on what communities most need, whether it is marketing materials, website development, conference and tradeshow registrations, or continuing economic development education.

Workforce Readiness

The Duke Energy Foundation's Workforce Development Program aims to meet local employers' needs while providing resources and education to the workforce of the future. Some recent investments through this program, which are helping strengthen Indiana's talent pipeline, include:

- **Ivy Tech**: In 2023, the Duke Energy Foundation awarded Ivy Tech's Franklin campus a $30,000 grant to support its Johnson County Advanced Manufacturing Program. A year later, the program successfully opened an advanced manufacturing lab, and 26 students have now participated in the program, with 24 earning industry-recognized certificates, and five already securing manufacturing jobs.

- **Vincennes University**: The Duke Energy Foundation awarded Vincennes University a $50,000 grant in 2023 for its Battery Technical Training Course, which resulted in trained technicians who are now employed by top regional employers in battery technology. The university collaborated with the Battery Innovation Center and industry leaders such as Cummins, Toyota, and others to develop a comprehensive seven-week training program, offering full-tuition scholarships to students who secured employment with partner companies.

- **HIRE**: The Indiana Department of Corrections' Hoosier Initiative for Re-Entry ("HIRE") program received a $250,000 Duke Energy Foundation grant to provide educational opportunities for formerly incarcerated citizens. To alleviate barriers to successful employment and develop new partnerships with Indiana businesses, the grant funded scholarships through Ivy Tech Community College for 141 individuals across 16 counties, with 136 enrollees completing training. The program offered customized energy technology and solar panel installation training to help fill the state's need for qualified solar panel installation workers. The grant also funded education for employers to aid them in hiring this population.

Collaboration with Purdue University

Duke Energy Indiana partnered with Purdue University to study the feasibility of using small modular nuclear reactors to meet the future long-term energy needs of Purdue University's West Lafayette campus with the excess energy exported to the electric grid. The research sought to identify opportunities and recommendations for producing cleaner energy for the community and Indiana and economic opportunities such as job creation, local investment, and tax revenue. The study also explored challenges such as public acceptance, regulatory conditions, cost competitiveness, technology development, used fuel management, and skilled workforce availability.

One of the positive outcomes of the collaboration was public education. A co-sponsored, six-part lecture series, "Understanding Tomorrow's Nuclear Energy," featured professors, national industry leaders, and policy experts who helped advance public understanding of nuclear energy and recent advances in the field. More than 4,900 individuals participated in the series, either online or in person, demonstrating a high level of interest in the technology and its possibilities for the state.

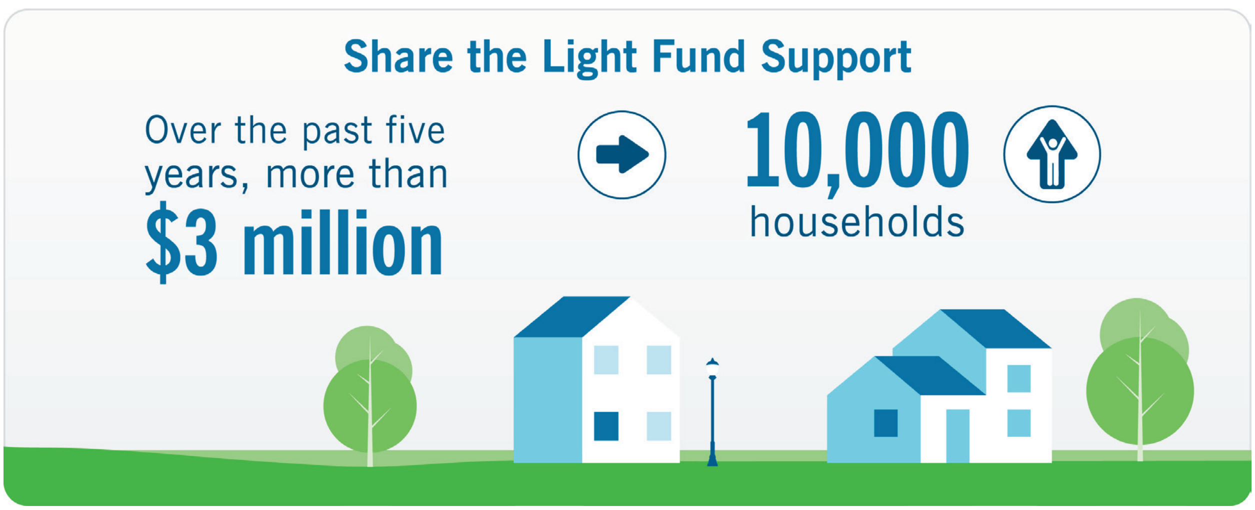
It is important to note that the process to site, permit, receive regulatory approval, build, and bring online advanced reactor generation is a lengthy process. If Duke Energy Indiana and Purdue University at any point in the future decide to pursue small modular reactors near campus or elsewhere in Indiana, public and stakeholder input will be an important part of the process.

Support for Underserved Populations

Low-Income Customer Assistance

Duke Energy Indiana knows that utility costs can be a significant part of any household budget and can be especially impactful to low-income customers. To help address these challenges, the Company has collaborated with state agencies, nonprofits, and stakeholders representing consumers to explore avenues for assisting vulnerable customers. This collaboration has resulted in reduced security deposits for Energy Assistance Program customers, automatic enrollment in payment plans for customers in arrears, and an opportunity for customers to round-up their electric bill payments to support the Company's Share the Light Fund for energy assistance as seen in Figure K-3 below.

Figure K-3: An Example of Low-Income Customer Support



From 2023 to 2024, Duke Energy Indiana also expanded its outreach to low-income customers by partnering with local nonprofits and social service agencies through resource fairs, food pantry openings, and community dinners. These events provided Hoosiers with opportunities to learn about a variety of local services, including those of Duke Energy Indiana, whose customer service representatives attended to assist with billing inquiries and enroll customers in state and federal energy assistance programs as well as the Company's energy efficiency offerings. The Company has reached approximately 11,500 customers in need through approximately 30 events, with more planned for the remainder of 2024.

Additional efforts to support low-income customers include:

- Duke Energy Indiana established the Centralized Agency Team as a single point of contact for utility assistance agencies and created a digital self-service portal. This portal allows agencies to process energy assistance commitments and payments, track past assistance, and receive notifications for new assistance deadlines. The improvements have streamlined the assistance process for agencies and customers. In 2023, Energy Assistance Program funding for Duke Energy's Indiana customers surpassed $15.5 million. The Share the Light Fund, supported by Duke Energy shareholders and voluntary contributions from customers, helps Duke Energy's low-income Indiana customers struggling with energy bills. Over the past five years, more than $3 million in bill assistance has been distributed through the fund to more than 10,000 Indiana households. The program collaborates with statewide community action agencies to identify customers who may be struggling financially and provide winter and summer bill relief.

- Duke Energy Indiana's Neighborhood Energy Saver Program offers free home energy assessments and energy efficiency upgrades to customers in low-income neighborhoods. In 2023, the program helped more than 1,200 Duke Energy Indiana customers make energy efficiency upgrades to their homes. Since the Neighborhood Energy Saver Program was launched in March 2015, nearly 12,000 Duke Energy Indiana households have received free home energy makeovers.

- Duke Energy Indiana partners with the Indiana Housing and Community Development Authority ("IHCDA") to support the Weatherization Assistance Program, which helps qualifying customers save energy and reduce expenses by making their homes more energy efficient. But before a home can be energy efficient, it must be safe. Over the last two years, Duke Energy Indiana has contributed $300,000 to support the IHCDA's Healthy Homes Production Program, which provides health and safety measures in homes eligible for weatherization under its program. In 2024, Duke Energy Indiana has pledged an additional $100,000 for the program, reinforcing its commitment to collaborating with IHCDA to benefit customers in need.

Supplier Diversity

Duke Energy Indiana looks for ways to expand its choices of suppliers to secure quality products and services at competitive prices. That includes looking at suppliers that are Indiana-based or that utilize local manufacturing and services. It also means ensuring that minority suppliers and veteran-owned operations know about opportunities to bid on the Company's products and services. This involves extensive outreach to groups such as the Mid-States Minority Supplier Development Council, the Indianapolis chapter of the National Association of Women Business Owners, and the Indiana Department of Administration's Division of Supplier Diversity. Additionally, Duke Energy Indiana serves as a member of the Indiana Energy Association's Supplier Diversity and Development Committee, which encourages collaboration among Indiana's utilities on opportunities to encourage the development and utilization of minority, women, and veteran-owned small businesses. The results have been productive. In 2023, Duke Energy Indiana invested more than $65 million with diverse businesses.

Aligned Interests

Duke Energy Indiana is working alongside its customers, communities, and stakeholders to deliver value and create lasting impact. This means providing accessible, reliable, and affordable energy to customers. It also means supporting community organizations with financial resources and employee time, attracting economic growth and investment to the state, engaging local and diverse suppliers, and considering how its operations affect communities in all its decisions. Duke Energy Indiana knows that its success depends on the vitality of the customers and communities it serves.

Cross Reference

Rule	Location in 2024 IRP Document
170 IAC 4-7-2 Integrated Resource Plan Submission	
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:	www.duke-energy.com/IndianaIRP
(1) The IRP.	2024 Integrated Resource Plan
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following:	2024 IRP Appendices
(A) The utility's energy and demand forecasts and input data used to develop the forecasts.	Appendix D
(B) The characteristics and costs per unit of resources examined in the IRP;	Chapter 3; Appendix F; Appendix C
(C) Input and output files from capacity planning models, in electronic format.	Attachment C-1
(D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file.	Attachment C-2
If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.	Appendix C, Confidential Technical Attachments
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual	Executive Summary

elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director. (B) A simplified discussion of the utility's resource types and load characteristics.	
The utility shall make the IRP summary readily accessible on its website.	www.duke-energy.com/IndianaIRP
170 IAC 4-7-2.6 Public Advisory Process	
(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	*Provided timely response to data requests throughout process*
(c) The utility shall solicit, consider, and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.	Appendix A
(d) The utility retains full responsibility for the content of its IRP.	No response required
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty.	Appendix A; Attachment A-1

(H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection. (2) The utility may hold additional meetings. (3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	
170 IAC 4-7-4 Integrated Resource Plan Contents	
An IRP must include the following: (1) At least a twenty (20) year future period for predicted or forecasted analyses.	Chapter 3; Appendix C; Appendix D
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Appendix D, Forecast Results & Commentary
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	Appendix D, Forecast Results & Commentary (Alternate Load Forecasts)
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	Appendix B; Appendix C
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Chapter 2, Analytical Process & Tools; Appendix C; Appendix H; Attachment H-1
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	Chapter 3, Supply-Side Resources and Demand-Side Resources; Chapter 4, Appendix C; Appendix F; Appendix H; Appendix I; Attachment H-1
(7) The resource screening analysis and resource summary table required by section 7 of this rule.	Appendix C; Appendix F; Appendix H; Attachment H-1

(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	Chapter 2, Analytical Framework and Analytical Process & Tools; Chapter 4; Appendix C
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Chapter 5
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Chapter 6
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	Chapter 2; Chapter 3
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	Attachment D-2
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	Appendix D
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	Appendix D

(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	Appendix D
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	Appendix B, Current Demand-Side Resources (Advanced Metering Infrastructure); Appendix D, Load Forecast Process & Enhancements
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).	Chapter 1
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	Appendix C; Appendix D; Appendix H
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Chapter 2, Analytical Process & Tools; Appendix C, Modeling Software & Development of Modeling Assumptions
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	Chapter 3
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	Appendix J
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Chapter 2, Resource Planning Objectives and Scorecard Evaluation Metrics
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Chapter 3; Chapter 4; Appendix C; Appendix J
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and	Chapter 5; Chapter 4, Portfolio Comparison & Evaluation

(D) uncertainty; were balanced in selecting its preferred resource portfolio.	
(25) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	Chapter 3
(26) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Chapter 2, Analytical Framework (Scenarios); Chapter 3
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC).	Appendix I

(C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.	
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast; (ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	(A) Chapter 2, Analytical Process & Tools and Advancements in Analytical Process; Appendix D, Load Forecast Process & Enhancements; Appendix C, Modeling Software & Development of Modeling Assumptions
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.	Appendix C
(30) A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.	Chapter 2, Stakeholder Engagement; Appendix A

(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Chapter 3; Appendix C; Appendix F; Appendix H; Attachment H-1
170 IAC 4-7-5 Energy and Demand Forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following:	Appendix D
(1) Historical load shapes, including the following: (A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	Appendix D, Forecast Results & Commentary (Historical Load Shapes); Attachment D-1 (Additional Load Shapes)
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	Appendix D, Forecast Results & Commentary; Appendix B, Load & Customer Characteristics; Appendix C, Forecasted Demand-Side Management (Demand Response); Appendix D, Forecast Results & Commentary (End-Use History and Forecast, Summary of History by Major Class
(3) Actual and weather normalized energy and demand levels.	Appendix D, Forecast Results & Commentary; Appendix B, Load & Customer Characteristics
(4) A discussion of methods and processes used to weather normalize.	Appendix D, Overview of Load Forecasting
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	Appendix D
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or, rate classes, or both. (C) Firm wholesale power sales.	Appendix D; Appendix B
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	Appendix D; Chapter 3, Load Forecast; Appendix C;

(8) Justification for the selected forecasting methodology.	Appendix D
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	Appendix D
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	Appendix D
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.	Appendix D
(c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	Appendix D
170 IAC 4-7-6 Description of Available Resources	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	Appendix B
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment.	Chapter 4; Appendix C
(3) A fuel price forecast by generating unit.	Chapter 3; Appendix C; Attachment C-1

(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and (D) subsequent disposal; (C) hazardous waste; and (D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units.	Chapter 4; Appendix C; Appendix J
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	Chapter 3; Appendix C; Appendix I
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy.	Chapter 3, Load Forecast; Appendix C, Electric Load Forecast and Forecasted Demand-Side Resources; Appendix D; Appendix H
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	Appendix H
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics, and parameters. (B) The method by which the costs, characteristics, and other parameters of the demand-side resource are determined. (C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings. (E) The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	Appendix C, Forecasted Demand-Side Resources; Appendix H; Attachment H-1

(3) Supply-side resources. For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of nondispatchable resources. (iv) Additional transmission facilities necessitated by the resource.	Chapter 3, Supply-Side Resources; Appendix C, Selectable Supply-Side Resources; Appendix F; Appendix I
(B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Chapter 3, Supply-Side Resources
(C) A description of significant environmental effects, including the following: (i) Air emissions. (ii) Solid waste disposal. (iii) Hazardous waste and subsequent disposal. (iv) Water consumption and discharge.	Chapter 4; Appendix C; Appendix J
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology (B) A description of the timing, types of expansion, and alternative options considered.	Appendix I
(C) The approximate cost of expected expansion and alteration of the transmission network.	Appendix C; Appendix I; Chapter 3;
(D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Appendix I; Chapter 6
(E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	Appendix I; Chapter 6
170 IAC 4-7-7 Selection of Resources	
(a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of	Appendix F

this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	
170 IAC 4-7-8 Resource Portfolios	
(a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	Chapter 2, Analytical Framework and Analytical Process & Tools; Chapter 4
(b) With regard to candidate resource portfolios, the IRP must include the following: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(25) of this rule.	Chapter 4, Portfolio Comparison & Evaluation; Appendix C
(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	Chapter 4, Portfolio Comparison & Evaluation
(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	Appendix C, Results of Production Cost Modeling
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio.	Chapter 5
(2) Identification of the standards of reliability.	Chapter 3, Reliability Requirements
(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	Chapter 3; Chapter 5
(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability;	Chapter 3; Appendix C

(C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	
(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost-effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	Chapter 5
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	Appendix H; Attachment H-1
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	Appendix C
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress.	Chapter 5
(B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Chapter 5
(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Chapter 2, Advancements in Analytical Process

(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Chapter 5; Chapter 6
170 IAC 4-7-9 Short Term Action Plan	
(a) A utility shall prepare a short term action plan as part of its IRP, and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	Chapter 6
(b) The short term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(9) of this rule, where the utility must take action or incur expenses during the three (3) year period.	Chapter 6
(c) The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.	Chapter 6; Chapter 5; Appendix I
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives.	Appendix H; Chapter 6, Demand-Side Resources
(3) The implementation schedule for the preferred resource portfolio.	Chapter 6, Overview of Short-Term Actions
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	Appendix C, Results of Production Cost Modeling
(5) A description and explanation of differences between what was stated in the utility's last filed short-term action plan and what actually occurred.	Chapter 6, Activities Since Submitting the 2021 Integrated Resource Plan

Indiana Code § 8-1-2-0.6	
1) Indiana Code § 8-1-2-0.6 Sec. 0.6. The general assembly declares that it is the continuing policy of the state that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the following attributes of electric utility service: (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.	Chapter 2; Chapter 4; Chapter 5

Glossary of Terms	
1898	1898 & Company
AC	Alternating Current
AEO	Annual Energy Outlook
AEP	American Electric Power
AMI	Advanced Metering Infrastructure
AR	Advanced Reactor
ARDP	Advanced Reactor Demonstration Project
BATW	Bottom Ash Transport Water
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
BOY	Beginning-of-Year
BPI	Building Performance Institute
BTM	Behind-the-Meter
BYOT	Bring Your Own Thermostat
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CASAC	Clean Air Scientific Advisory Committee
CC	Combined Cycle
CCS	Carbon Capture and Sequestration
CF	Capacity Factor
CHIPS	Creating Helpful Incentives to Produce Semiconductors and Science Act
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CONE	Cost of New Entry
COS	Cost of Service
CPCN	Certificate of Public Convenience and Necessity
CRA	Charles River Associates
CRL	Combustion Residual Leachate
CT	Combustion Turbine

CVR	Conservation Voltage Reduction
CWA	Clean Water Act
DART	Days Away, Restricted, or Transferred
DC	Direct Current
DDRE	Deep Decarbonization and Rapid Electrification
DEI	Duke Energy Indiana
DER	Distributed Energy Resources
DLOL	Direct Loss-of-Load
DMS	Distribution Management System
DOE	Department of Energy
DPP	Definitive Planning Phase
DR	Demand Response
DSM	Demand Side Management
ECC	Economic Carrying Charge
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EGUs	Electric Generating Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERA5	European Center for Medium-Range Weather Forecasting's Reanalysis v5
ESIG	Energy Systems Integration Group
ESP	Early Site Permit
EUE	Expected Unserved Energy
EV	Electric Vehicles
EVA	Energy Ventures Analysis
EVSE	Electric Vehicles Service Equipment
FEED	Front-End Engineering and Design
FERC	Federal Energy Regulatory Commission

FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FOM	Fixed Operations & Maintenance
FT	Firm Transportation
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIA	Generator Interconnection Agreement
GRR	Generator Replacement Request
GSA	Green Source Advantage
GW	Gigawatt(s)
GWh	Gigawatt Hour(s)
HAP	Hazardous Air Pollutants
HER	Home Energy Report
HHI	Herfindahl-Hirschman Index
HIRE	Hoosier Initiative for Re-Entry
HPS	High Pressure Sodium
HVAC	Heating Ventilation and Air Conditioning
IAC	Indiana Administrative Code
IBR	Inverter-Based Resource
ICAP	Installed Capacity
ICCT	International Council on Clean Transportation
ICE	Internal Combustion Engine
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
IHCDA	Indiana Housing and Community Development Authority
IIJA	Infrastructure Investment and Jobs Act
IMPA	Indiana Municipal Power Agency
IRA	Inflation Reduction Act of 2022
IRP	Integrated Resource Plan
ISD	In-Service Date
ITC	Investment Tax Credit

IURC	Indiana Utility Regulatory Commission
IVVC	Integrated Voltage-VAR Control
JTS	Joint Transmission System
kV	Kilovolt(s)
kW	Kilowatt(s)
kWh	Kilowatt-Hour(s)
LBA	Local Balancing Authority
LCOE	Levelized Cost of Energy
LDES	Long-Duration Energy Storage
LED	Light-Emitting Diode
LGIA	Larger Generator Interconnection Agreement
Li-on	Lithium Ion
LLF	Low Load Factor
LMR	Load Modifying Resource
LOLE	Loss of Load Expectation
LRTP	Long Range Transmission Plan
LRZ	Local Resource Zone
LSE	Load Serving Entity
LWR	Light-Water Reactor
MACRS	Modified Accelerated Cost Recovery System
MATS	Mercury and Air Toxic Standards
MED	Major Event Day
MH	Metal Halide
MISO	Midcontinent Independent System Operator
MMBtu	Million British Thermal Units
MPS	Market Potential Study
MSRP	Manufacturer’s Suggested Retail Price
MTEP	MISO Transmission Expansion Planning
MV	Mercury Vapor
MVA	Megavolt-Ampere
MW	Megawatt(s)

MWe	Megawatt-Electric
MWh	Megawatt-Hour(s)
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NAPEE	National Action Plan for Energy Efficiency
NDA	Non-Disclosure Agreement
NERC	North American Electric Reliability Corporation
NES	Neighborhood Energy Saver
NESHAP	National Emission Standards for Hazardous Air Pollutants
NEVI	National Electric Vehicle Infrastructure
NG	Natural Gas
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
NSRDB	National Renewable Energy Laboratory’s National Solar Radiation Database
OPA	Other Public Authorities
OSB	Oversight Board
OSHA	Occupational Safety and Health Administration
PHEV	Plug-In Hybrid Electric Vehicle
PJM	Pennsylvania – New Jersey – Maryland Interconnection
PM	Particulate Matter
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PSH	Pumped Storage Hydropower
PTC	Production Tax Credit
PV	Photovoltaic

PVRR	Present Value of Revenue Requirements
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Certificate
RFC	Reliability First Corporation
RFP	Request for Proposals
RI	Resource Innovations
RTC	‘Round-the-Clock
RTO	Regional Transmission Organization
RTR	Residual Risk and Technology Review
SAC	Seasonal Accredited Capacity
SAE	Statistically Adjusted End-Use
SAIDI	System Average Interruption Duration Index
SAT	Single-Axis Tracker
sCO_2	Supercritical Carbon Dioxide
SCR	Selective Catalytic Reduction
SERVM	Strategic Energy and Risk Valuation Model
SIP	State Implementation Plan
SME	Subject Matter Expert
SMR	Small Modular Reactor
SPS	Solar Paired with Storage
ST	Steam Turbine
T&D	Transmission and Distribution
TDSIC	Transmission Distribution and Storage System Improvement Changes
TICR	Total Incident Case Rate
TOU	Time-of-Use
TTF	Time-to-Failure
TTR	Time-to-Repair
TWh	Terawatt-Hour(s)
UCAP	Unforced Capacity
UCT	Utility Cost Test
UEE	Utility Energy Efficiency

VAST	Vehicle Analytics and Simulation Tool
VOM	Variable Operations and Maintenance
VPP	Virtual Power Plant
W&A	Wage and Apprenticeship
WACC	Weighted Average Cost of Capital
WVPA	Wabash Valley Power Alliance