DUKE ENERGY
INDIANA


# 2021
# DUKE ENERGY INTEGRATED RESOURCE PLAN

**VOLUME I 12.15.21**

# VOLUME I
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2021 DUKE ENERGY INDIANA
INTEGRATED RESOURCE PLAN

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# VOLUME I
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2021 DUKE ENERGY INDIANA
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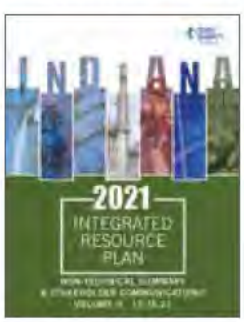

SECTION

# EXECUTIVE SUMMARY

## A. OVERVIEW

Duke Energy is a century-old company with a history of providing safe and reliable service to its customers – and as Duke Energy looks to the future, it has committed to transitioning to cleaner energy. In 2019, Duke Energy announced a corporate commitment to reduce $CO_2$ emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050. This is a shared goal important to the Duke Energy's customers and communities, many of whom have also developed their own clean energy initiatives.

Duke Energy Indiana ("Duke Energy Indiana" or the "Company")[1] serves more than 860,000 customers. Over the next decade, the way in which Duke Energy Indiana serves the state will require an orderly and responsible transition that also balances reliability and affordability for customers. Duke Energy Indiana's 2021 Integrated Resource Plan ("IRP" or the "Plan") outlines an approach that:

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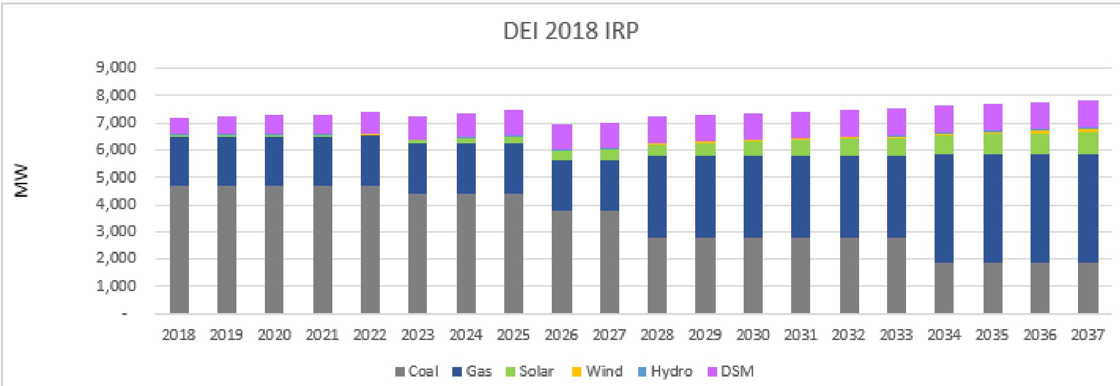
[1] Duke Energy Indiana is Indiana's largest electric utility, serving approximately 860,000 electric customers in 69 of Indiana's 92 counties covering North Central, Central, and Southern Indiana. Its service area spans 23,000 square miles and includes Bloomington, Terre Haute, and Lafayette, and suburban areas near Indianapolis, Louisville, Ky. and Cincinnati, Ohio.

- accelerates carbon reductions by retiring all coal fired power generation by 2035,
- triples renewable energy additions to the system compared to the prior IRP (from 2018),
- harvests more energy efficiency and demand response opportunities, and
- maintains a strong focus on reliability, resiliency and affordability.

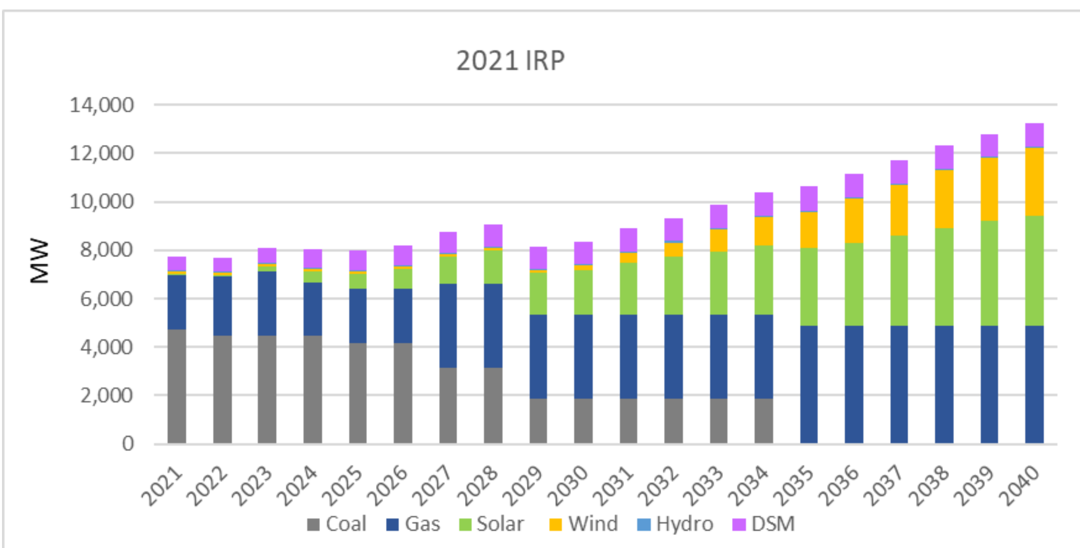
Additionally, Duke Energy Indiana uses the MISO energy market strategically, to supplement its generation with the result being a low cost, balanced, diverse mix that is not overly dependent on the market.

As Duke Energy Indiana began to develop various scenarios, the Company considered the input of more than 100 stakeholders in a year-long process, including eight public stakeholder meetings and two evening sessions for customers. This aligns with the Company's broader approach to engage stakeholders and consider their input and perspectives  as Duke Energy Indiana develops and executes on the Company's climate strategy. Because the IRP covers such a long time period, it is revaluated every three years based on changing factors such as energy demand, environmental regulations, and fuel and power prices.

In its last IRP in 2018, Duke Energy Indiana outlined intentional steps toward a clean energy transition by accelerating retirement dates of its coal plants by an average of nine years and adding renewable resources to its system, while ensuring reliability and customer affordability.




This 2021 IRP advances the work of the 2018 IRP, reflecting updates in load, technology, the cost of resources and fuels etc. The result is the further acceleration of coal plant retirements an average of an additional four years, tripling renewable solar and wind energy resources, adding other clean resources (including storage, energy efficiency and demand response), and a future that takes advantage of new and emerging technologies that meet customers' energy and capacity needs.




**Energy Diversity, Reliability, and Flexibility.** Duke Energy Indiana developed this IRP with a keen focus on diversity of fuel sources, reliability and flexibility of the system. Some generation sources have fewer environmental emissions; some are more economic; and some are required for meeting our customers' energy needs – 24/7/365. A balanced mix is necessary to serve customers in the most reliable and economical way possible while using increasingly clean forms of energy. The IRP includes a diverse set of resources, including strategic purchases from the energy market, resulting in a fleet that is not over-reliant on one particular resource type and maintains fleet flexibility and optionality. The Plan includes resources such as a natural gas combined cycle plant and continued operations of the Edwardsport IGCC plant on coal until 2035, providing reliable baseload generation. This approach ensures Duke Energy Indiana can meet its customers' needs with its own generation and appropriately uses the energy market to lower costs for customers without being overly-dependent on the market.

**Cleaner Energy.** Our focus on leading the industry's energy transition has extended well beyond the last few years. We have been committed to protecting the environment and investing in new technology for decades. Since 2005, Duke Energy Indiana has decreased its sulfur dioxide emissions by 96 percent, nitrogen oxide emissions by 73 percent and carbon emissions by 42 percent. Duke Energy Indiana's objective is to serve customers with reliable, predictable service at affordable rates. The Company's 20-year plan aligns with that intent and includes the following:

- 4,525 megawatts of solar power, including 400 megawatts of energy storage paired with solar,
- 2,800 megawatts of wind energy, and
- 2,381 megawatts of cleaner-burning natural gas turbine generation that is also capable of utilizing hydrogen to reduce or eliminate carbon dioxide emissions, pending

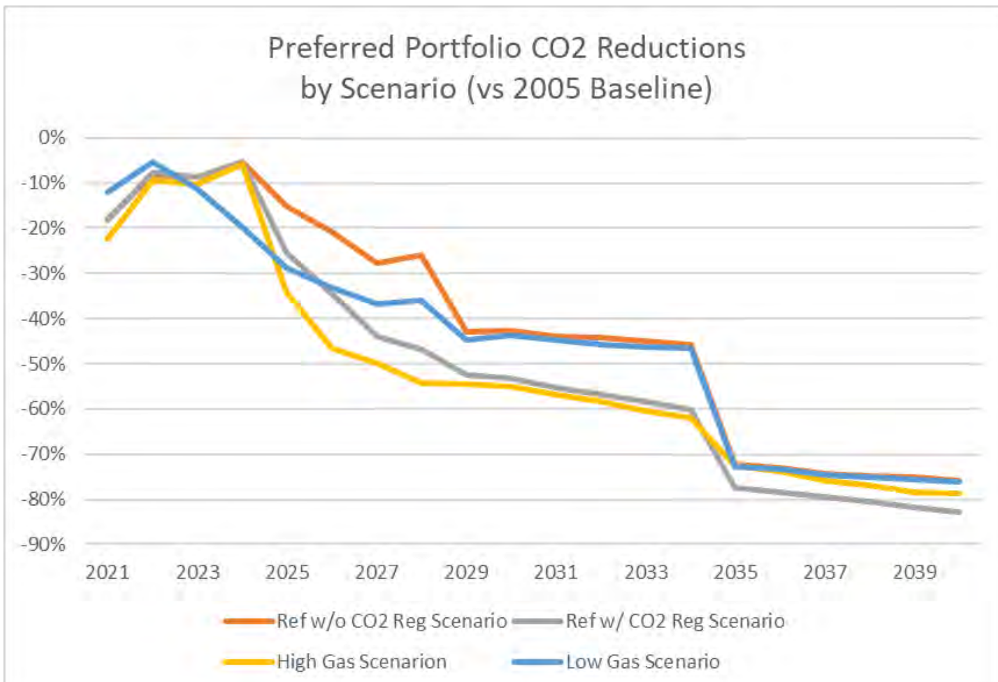
development of a reliable supply of cleanly sourced hydrogen fuel. Turbine technology will maintain our ability to provide dispatchable power that is not weather-dependent.

These new investments in cleaner energy are in addition to the continuing operation of the Company's Crane solar plant in Southern Indiana, the recent investment in the Markland Hydroelectric plant to increase its output of carbon-free power, and the renewable power we purchase.

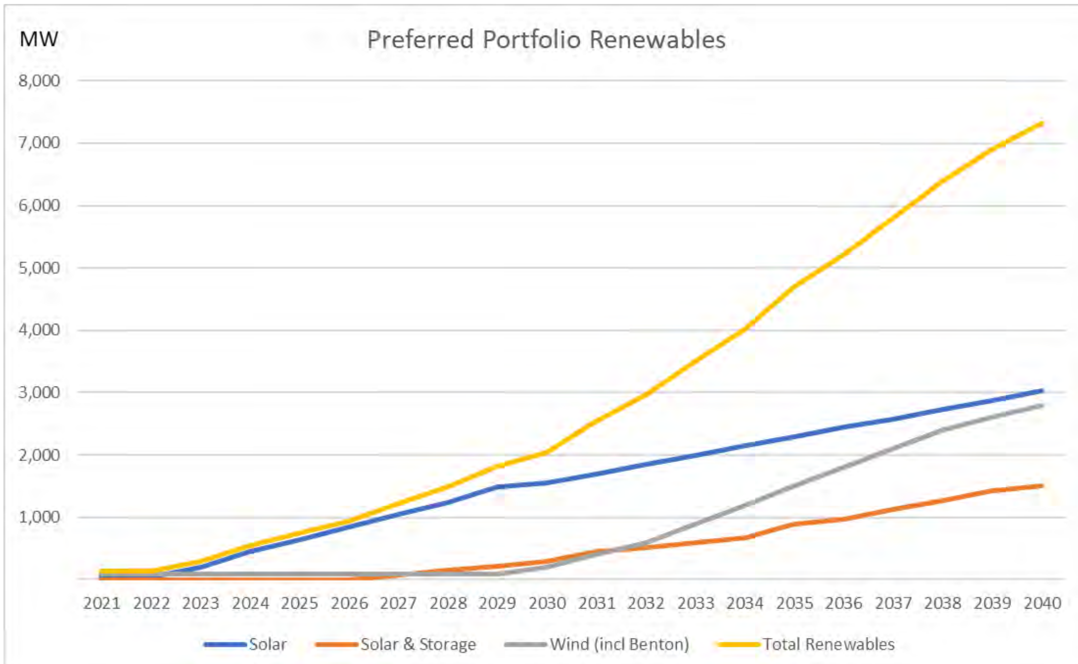
As a prudent operator with an obligation to adequately and reliably serve its customers, both today and for decades to come, Duke Energy Indiana must anticipate the potential for changes in environmental policy and power markets that will require further revision to the Company's resource planning. The environmental sustainability of the preferred portfolio is an important consideration and this IRP prioritizes sustainability by reducing carbon emissions, increasing renewables and retiring coal generation.

In the Reference with Carbon Regulation scenario, Duke Energy Indiana's Plan would reduce carbon emissions 63% by 2030 and 88% by 2040 from Duke Energy Indiana's owned generation, relative to 2005 levels. As shown in the graph below, including emissions related to market purchases, the Plan would reduce $CO_2$ 53% by 2030 and 83% by 2040 relative to 2005 $CO_2$ emissions.

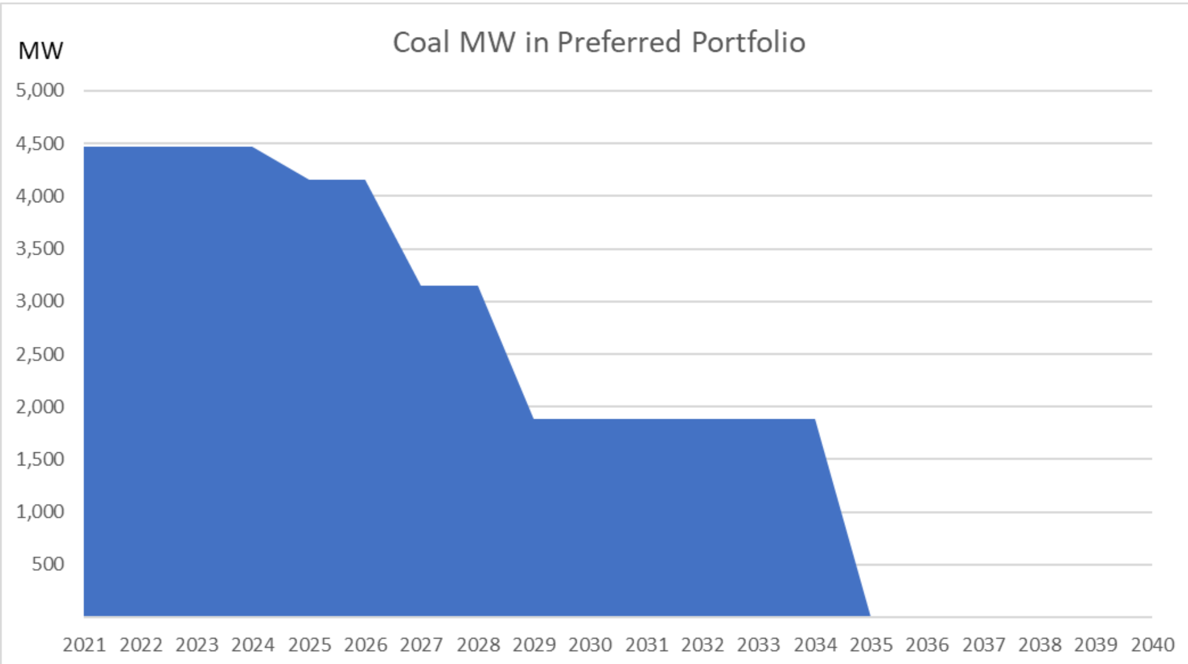
## Preferred Plan $CO_2$ Emissions



# DUKE ENERGY INDIANA'S PLAN TRIPLES THE AMOUNT OF RENEWABLES OVER ITS 2018 IRP



## DUKE ENERGY INDIANA'S PLAN SIGNIFICANTLY REDUCES RELIANCE ON FOSSIL FUEL RESOURCES AND RETIRES ALL COAL FIRED UNITS BY 2035




**Energy Efficiency and Demand Response.** Energy efficiency and demand response not only save customers money, these programs also help the Company avoid building new generation assets. Duke Energy Indiana considers these programs a win-win for customers and communities, as well as achieving clean energy and environmental targets. Over the last decade, Duke Energy Indiana's energy efficiency programs have helped customers save more than 2 billion kilowatt-hours of energy. The 2021 IRP recommends increasing energy efficiency by 20% and sustaining a high level of demand response, which avoids the addition of over 400 MW of new resources in the process.

**Affordability.** While preserving options and diversifying the generating fleet is important, Duke Energy Indiana recognizes the criticality of customer affordability. The IRP balances the need for reliability and environmental sustainability with the importance of competitive and affordable rates. The average five-year rate impact of Duke Energy Indiana's preferred portfolio is about 1.3%.

In developing the Plan, Company personnel analyzed both quantitative and qualitative factors. For example, quantitative analysis provides insights into metrics and future risks and uncertainties associated with the load forecast, fuel and energy costs, affordability, the transition to clean energy, and costs associated with generation resource options. Qualitative perspectives, such as the importance of fuel and resource diversity, portfolio flexibility, reliability, resiliency, and technology development and deployment are key considerations as long-term decisions regarding new resources are made. The end result is a resource plan that serves as a valuable guide for Duke Energy Indiana as we make business decisions to meet customers' near-term and long-term energy needs.

Integrated resource plans provide a roadmap – they are not final documents or decisions. As the pace of change in the energy industry continues to increase and intensify, our assumptions about plant retirement dates and power generation replacements will evolve. A few of these critical uncertainties in the industry include:

- emerging federal environmental regulations that will make coal-fired generation more challenging,
- growing interest by customers, lenders and investors who want cleaner energy sources,

- changing load growth,
- fuel and power prices, and
- technological innovation.

Given the ever-changing regulations and sustainability expectations affecting our resource planning process, the IRP provides general direction at this time, while leaving room for the specific tactical resource decisions to be updated through Commission filings using the most current information. This check-and-adjust approach with each IRP cycle allows Duke Energy Indiana to monitor the long-term direction and strategy in its IRPs and submit more focused proposals as it executes on specific resource decisions through a planned Request For Proposal (RFP) and the certificate of public convenience and necessity (CPCN) process.

## B. KEY IRP ISSUES

### 1. PROGRESS TOWARD ENVIRONMENTAL SUSTAINABILITY

Carbon regulation has been debated for over a decade – and that debate continues as we prepare and submit this plan. We are participating in the process to advocate for smart solutions for the future and energy policy that balances clean energy targets with affordability and reliability.

With this in mind, Duke Energy Indiana has modeled various levels and forms of regulation to provide multiple options. Although much is still not known about how carbon regulation might be promulgated, the analysis over the last several IRPs has identified the need to reduce carbon emissions as a planning assumption, which drives the generation transition demonstrated in the IRP portfolios.

Both public sentiment and environmental, social and governance (ESG) investors' concern about climate change is growing – and significant climate policy options are being debated in Congress at the same time regulatory options are under consideration by the federal Environmental Protection Agency. We believe carbon regulation/policy should be viewed as more of a matter of "when", rather than "if," and thus warrants consideration in the plan. Beyond federal regulation, many of our large business and industrial customers also have sustainability goals and emissions targets that we are committed to supporting. Based on the anticipated magnitude of change that would be driven by substantive carbon regulation, and the evolving goals our customers, lenders and investors are setting, a measured transition toward net-zero carbon by 2050 is prudent even in the absence of legislation or regulation.

As such, this IRP includes a Reference case with carbon regulation that applies a cost adder on carbon emissions in resource selection as well as daily operations. This is effectively a "shadow price" on carbon emissions. A "shadow price" is a generic proxy that could represent the effects of a price of emissions allowances, a price signal needed to meet a given clean energy standard, or a carbon tax. In this IRP, Duke Energy Indiana included a carbon price in the Reference case of $5/ton starting in 2025 and growing $5/ton per year.

We have utilized a range of carbon policy scenarios, such as a "zero price," a moderate carbon price, and a mass carbon cap. With these options, we can navigate the uncertainty around federal climate change legislation and environmental regulations and still view realistic modeling. As the industry receives additional clarity around future legislative or regulatory climate change policy, Duke Energy Indiana will adjust its assumptions related to carbon emissions, as warranted.

## 2. RETIREMENT ANALYSIS

Although coal plants have provided reliable service for many decades, many of these units are nearing the end of their useful lives, and will need to be retired to achieve our emissions reduction targets. As such, Duke Energy Indiana conducted a type of modeling that allows the user to optimize retirement decisions for the generation fleet and resource additions simultaneously. Duke Energy Indiana did not place constraints on the optimized model runs related to retirement decisions, so the optimized portfolios do not factor in real world issues, such as the savings resulting from retiring an entire generation site at one time or the challenges of adding multiple large natural gas plants within a year of each other. For these reasons, Duke Energy Indiana typically takes the learnings from the optimized runs and develops several hybrid portfolios, which can account for realistic constraints.

The preferred portfolio's coal retirement trajectory reflects a mid-point of the retirements in the optimized portfolios in the carbon regulation scenario and the no-carbon regulation scenario. Adjusting for a more orderly generation transition, as well as expectations for climate change regulation and policies, the preferred portfolio modeling results in Duke Energy Indiana retiring all coal generation by 2035.

In the 2021 IRP, Duke Energy Indiana's retirement analysis considered multiple operating conditions for its newest coal plant, the Edwardsport integrated gasification combined cycle ("IGCC") plant. This analysis includes the following operation conditions:

- operating on coal,
- operating on natural gas, and
- near-term retirement,

The optimized runs generally resulted in switching Edwardsport IGCC to only natural gas operations early in the 20-year period; however, this does not account for real-world IRP implications. Many qualitative considerations play into the decision, including:

- Edwardsport is Duke Energy Indiana's newest and cleanest coal plant, which has a trajectory of improving operations and lowering costs.
- The need for diverse fuel sources as we transition to cleaner energy and Edwardsport provides resource diversity in the longer term, potential options for carbon capture utilization and storage, and reliability benefits of dispatchable, onsite fuel source.
- Uncertainty about carbon prices, gas prices and availability, new technology availability and timing, and the need for reliability in the MISO region (from an energy and capacity perspective).

Additionally, a decision to move to full time natural gas operations at Edwardsport IGCC is virtually a permanent decision and very difficult to reverse. There are required air permitting changes, loss of specialized workforce for the gasification process, coal contract issues and operational challenges with restarting on coal. In some of the hybrid portfolios, including the preferred portfolio, these items were considered – and as a result, in the preferred portfolio, Duke Energy Indiana continues to operate Edwardsport IGCC on coal through 2035, striking a balance across many considerations – reliability, affordability, carbon reduction, and fleet flexibility and diversity .[2] Duke Energy Indiana will continue to analyze the issue and update the analysis in our next IRP, currently scheduled for 2024.

[2] The IRP assumes that by 2035, either the gasifiers will retire and the plant will move to full time natural gas operations or developments in carbon capture utilization and storage have advanced to provide for lower carbon emissions from the plant.

Edwardsport is a unique plant and provides flexibility given it can operate on either natural gas or coal. Duke Energy Indiana commits to analyze the potential for more seasonal operations at the plant (subject to approval by the IURC and MISO and review of the independent market monitor). For instance, the plant could switch to partial natural gas operations when economic to do so in the shoulder months, providing customers with lower fuel costs and a lower carbon footprint during certain times of the year. Then, it could shift back to reliable coal operations in the peak summer and winter months. Any changes in dispatch strategy would require the development of an appropriate fuel and transportation strategy, as well.

## 3. MODELING ENERGY EFFICIENCY (EE) AND DEMAND RESPONSE PROGRAMS AS A SUPPLY-SIDE RESOURCE

Energy efficiency and demand response options represent meaningful supply-side resources and Duke Energy Indiana has expanded modeling of these options in the last several IRPs. We worked collaboratively with stakeholders on an energy efficiency market potential study (MPS), which included base and enhanced assumptions for energy efficiency. Duke Energy Indiana ultimately created ten energy efficiency bundles, which were optimized in the IRP process and selected based on economics. Our preferred portfolio includes an enhanced level of energy efficiency as compared to its existing programs, generating additional cumulative energy savings of about 20% over the next 25 years – and reducing average annual electric sales by over 1%.

The preferred portfolio also includes continued year-over-year demand response of approximately 600 megawatts, reflecting its current special contracts and robust

PowerShare® program continuing during the 20-year period. Duke Energy Indiana will continue to monitor potential changes to demand response policy via FERC's Order No. 2222. MISO is currently developing rules for how distributed generation and demand response may be able to participate in the wholesale market, with a proposal expected in mid-2022. The Company will follow this closely and update in future planning, as appropriate.

## 4. THE PROJECTED LOAD FORECAST AND MISO RESOURCE ADEQUACY CHANGES

Duke Energy Indiana updates its load forecast at least twice a year. For this IRP, the Company has used the spring 2021 forecast. Overall, Duke Energy Indiana's load is forecasted to grow less than 1% annually.

Duke Energy Indiana had MISO present at its IRP stakeholder meeting, and MISO has shown a general need for additional generating capacity in the Indiana zone. Duke Energy Indiana also continues to monitor potential policy changes from MISO that could impact the capacity needs to maintain system reliability. MISO has proposed a new seasonal accreditation capacity (SAC) construct in late 2021. The specifics of the proposal have been under development as we have prepared this IRP. Although Duke Energy Indiana knows there will be impacts from these proposed changes and SAC could require additional capacity resources, the Company does not currently have clarity around the specific impacts to resource requirements.

Duke Energy Indiana's analysis reviewed the portfolios to ensure each met the current reserve requirement in both the summer and winter seasons. As the resource mix changes, Duke

Energy Indiana may switch from a summer planning utility to a winter planning utility in the early 2030s.

As we look ahead, Duke Energy Indiana will continue to closely monitor the potential MISO construct changes given the impacts to reliability, potential new resource additions and/or need for capacity purchases to ensure compliance with the new requirements.

## 5. TECHNOLOGY INNOVATION AND ADVANCEMENT

To achieve significant carbon reductions and maintain reliability, Duke Energy Indiana assumes new technology advancements and innovation will be developed and expanded to utility-scale level. This will require supportive energy policy at the state and federal levels – and a commitment to research and development of these technologies.

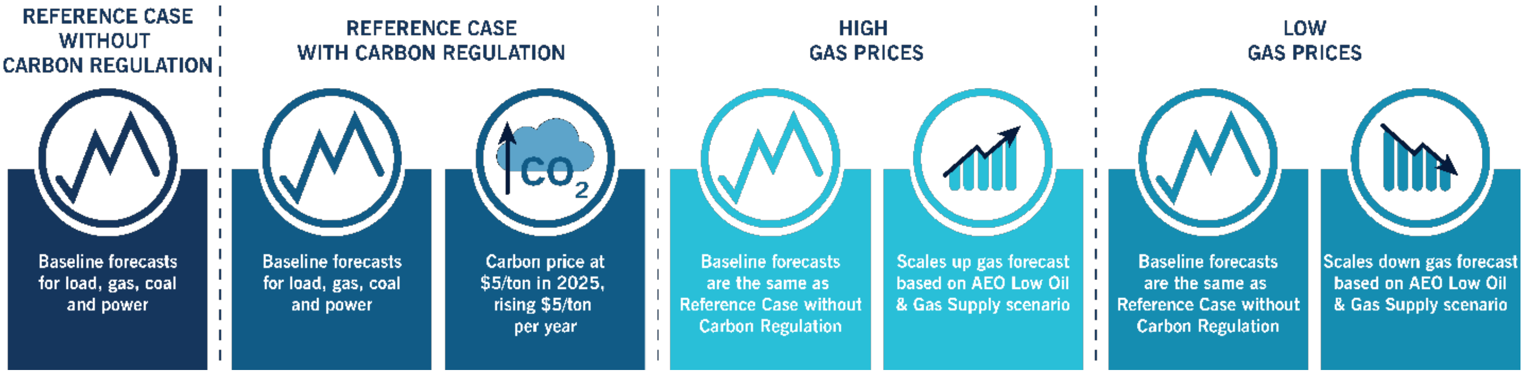
The preferred portfolio reflects Duke Energy Indiana's expectation that fully-hydrogen capable combustion turbines (CTs) will be commercially available to be deployed by 2035, and that turbines deployed in the 2020s would be modifiable to support additional hydrogen capability. The capability of CTs to operate on 100% hydrogen remains dependent on the development of technology to cost effectively produce and transport green hydrogen (or ammonia). To become truly viable, the hydrogen economy needs to provide a reliable fuel supply. At this time, it is not yet clear whether hydrogen will advance more quickly or less quickly than other emission-free, dispatchable generation options, such as nuclear small modular reactors (SMRs), advanced long-term storage, or carbon capture utilization and storage. Duke Energy Indiana built its preferred portfolio to be flexible, so the Company can pivot to the most cost effective and reliable technology available at the time.

The remainder of this Executive Summary presents an overview of the scenarios and portfolios used to determine the preferred resource plan. Further details regarding the planning process, issues, uncertainties and alternative plans are presented in following chapters. See Appendix G for an index of the information required by the Commission's IRP Rules.

## C. PLANNING PROCESS AND RESULTS

Duke Energy Indiana created a plan that accounts for and analyzes various future scenarios to provide the most prudent and reasonable approach possible. The Company will remain flexible and adjust to evolving regulatory, economic, environmental and operating circumstances. Stakeholder input and thematic elements of our discussions during stakeholder forums informed the development of four distinct, internally consistent scenarios.

## FOUR SCENARIOS FOR POTENTIAL FUTURES




## THIRTEEN PORTFOLIOS

Once the specific modeling assumptions for each scenario were determined, a capacity expansion model was used to optimize a portfolio for that scenario. More detailed information on each portfolio can be found in Section V.

## OPTIMIZED RESOURCE PLANS

1. Reference Case without Carbon Regulation Portfolio- most coal runs through IRP period; adds CC and almost 1,200 of renewables;
2. Reference Case with Carbon Regulation Portfolio- All coal retires by 2031; 2 CCs added in 2027; over 6,000 MW of renewables
3. High Gas Prices- most coal runs until the end of the IRP period; 3,400 MW of renewables
4. Low Gas Prices- all coal retires by 2029; 2 CCs added in 2027; 225 MW of renewables

## HYBRID PORTFOLIOS

The second group of portfolios was developed by evaluating the optimized portfolios for lessons learned as well as lessons learned from several key sensitivities. The portfolios coming out of that process are:

5. Balanced Hybrid- retires approximately half of coal fleet in 2020s; adds 2 CCs; 3,700 MW of renewables
6. Renewables-CC Hybrid- most coal retires by 2030; adds 2 CCs; 5,500 MW of renewables
7. Renewables/CC/CT Hybrid (the preferred portfolio)- out of coal by 2035; adds one CC in 2027; 1,160 MW of CT in 2035; and 7,325 MW of renewables
8. Renewables-CT Hybrid- most coal retires by 2030; adds 1,400 MW of CTs; 6,275 MW of renewables

## STAKEHOLDER PORTFOLIOS

Duke Energy Indiana's stakeholders and their input were valuable elements in the development of this plan. The stakeholder collaboration and engagement process provided robust discussion and outputs – and resulted in five stakeholder derived portfolios, which reflect the preferred resource mixes of various stakeholder groups.

9. Biden 100 - 100% $CO_2$ reduction by 2035
10. Biden 90 - 90% $CO_2$ reduction by 2035
11. Environmentally Focused - out of coal by 2030; no new gas and adds renewables
12. Reliable Energy- balanced transition of generation fleet; adds carbon capture sequestration to Edwardsport
13. Deep Decarbonization / Rapid Electrification- significant $CO_2$ reduction by early 2030s

and load growth due to increased electrification of the economy[3]

## DECISION CRITERIA

The objective of the IRP process is to produce a robust portfolio that meets load obligation while minimizing the Present Value Revenue Requirements (PVRR) at a reasonable level of risk, subject to laws and regulations, reliability and adequacy requirements, and operational feasibility. Also, the selected plan must meet MISO's 9.6% reserve margin requirement using MISO's current unforced capacity calculation (UCAP).[4]

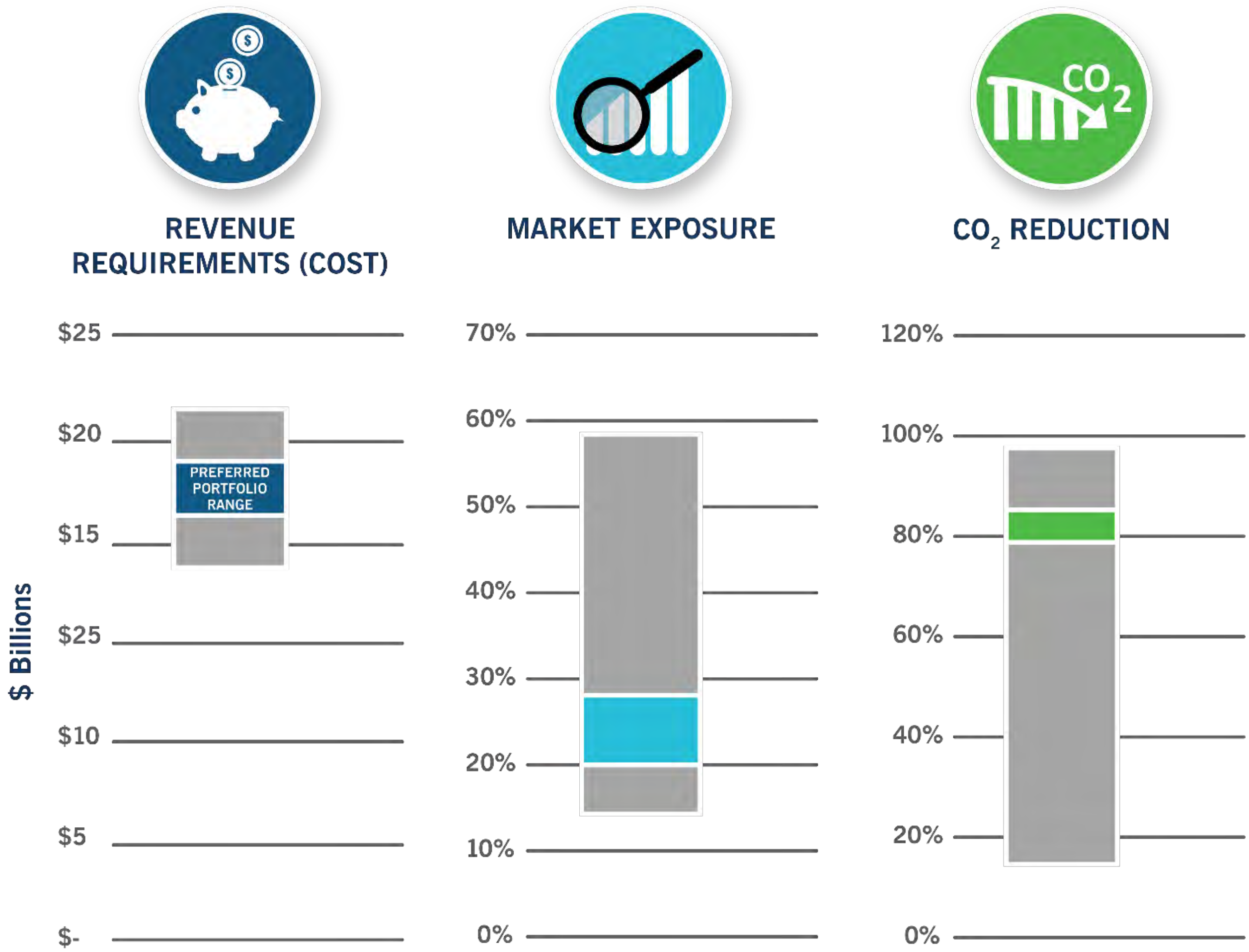
In the 2021 IRP, Duke Energy Indiana used predetermined decision criteria to assist in its ultimate selection of the preferred portfolio. The decision criteria were based in large part on the energy policy priorities outlined in the 21st Century Energy Policy Taskforce Report from the Indiana General Assembly issued in 2020: Reliability, Resilience/Stability, Affordability, Environmental Sustainability and Portfolio Flexibility. Much of the criteria can be measured quantitatively, such as meeting capacity and energy requirements for reliability, customer rate impact and carbon reductions; however, some criteria are more qualitative in nature, such as flexibility and executability.

Based on its superior performance in scenario and sensitivity analyses, the Renewables/CC/CT Portfolio was selected by Duke Energy Indiana as the preferred resource

[3] Note that Duke Energy Indiana continues to work with the stakeholder to further specify this scenario and portfolio, and the results are therefore not included herein.

[4] As detailed more above, MISO is currently proposing changes to its resource adequacy construct including looking at seasonal reserve margin requirements and changes to capacity accreditation. These changes were not well defined enough to model in this IRP, but Duke Energy Indiana did review each portfolio to determine whether it met the current reserve requirement in both the summer and winter seasons.

plan. This portfolio stands out due its combination of relatively low cost, lower carbon emissions and greater resource diversity with lower exposure to market risk. The preferred portfolio also has the flexibility to adjust for different forms of carbon regulation or the changing economics of renewables, storage, and natural gas generating resources. The table below shows the performance of the preferred portfolio on key metrics compared to the range of other portfolio's analyzed.




## SHORT TERM

As shown in Table 1-B below, the Preferred Portfolio features a measured approach with moderately accelerated coal retirements, additions of natural gas for continued reliability and progressively adding renewable generation, beginning with solar in the short term. The benefit of this Plan is the flexibility to adjust to changing market and regulatory conditions, as well as a smooth fleet transition to one that is more diverse and less carbon intensive.

The Company is committed to an RFP process for the near-term resource needs included in the Plan – *i.e.*, solar and natural gas additions. More details on that process can be found in the short-term action plan section of the IRP.

## LONG TERM

Duke Energy Indiana crafted the preferred portfolio with flexibility in mind, allowing the Company to increase renewables based on policy outcomes or cost, pivot to take advantage of natural gas should prices decrease, and adjust transition timing if carbon regulation is delayed. Duke Energy Indiana's preferred portfolio also prioritizes a diverse set of resources and positions the generation fleet to have greater flexibility and reliability, while also reducing carbon and maintaining affordability.

As we look ahead, Duke Energy Indiana's 2021 IRP offers a guide for the future – one that accelerates Duke Energy's path to net-zero carbon emissions in a measured, reliable and affordable manner for customers. This will be a collective effort with customers, communities and broad range of stakeholders to ensure an orderly and thoughtful transition. As innovative technology advances and scales, Duke Energy Indiana will make more informed recommendations about viable and reliable long-term resources that deliver the most value for customers during this energy transformation. Duke Energy Indiana looks forward to continued engagement and collaboration to chart a path forward that balances affordability, reliability and sustainability, ensuring Indiana is well positioned for a cleaner energy future.

## TABLE 1-A
## OVERVIEW OF THE PREFERRED RESOURCE PLAN

| | Coal Retirements | Gas Additions | Cumulative Renewables | | |
|---|---|---|---|---|---|
| | | | Solar | Wind | Solar + Storage |
| 2021 | Gallagher 2&4 (280 MW) | | 47 | 100 | |
| 2022 | | | 47 | 100 | |
| 2023 | | | 197 | 100 | |
| 2024 | | | 447 | 100 | |
| 2025 | Gibson 5 (313 MW) | | 647 | 100 | |
| 2026 | | | 847 | 100 | |
| 2027 | Cayuga 1&2 (1005 MW) | CC (1221 MW) | 1,047 | 100 | 75 |
| 2028 | | | 1,247 | 100 | 150 |
| 2029 | Gibson 3&4 (1262 MW) | | 1,497 | 100 | 225 |
| 2030 | | | 1,547 | 200 | 300 |
| 2031 | | | 1,697 | 400 | 450 |
| 2032 | | | 1,847 | 600 | 525 |
| 2033 | | | 1,997 | 900 | 600 |
| 2034 | | | 2,147 | 1,200 | 675 |
| 2035 | Gibson 1&2 (1270 MW) Edwardsport coal gasification (32 MW) [5] | CT (1160 MW) | 2,297 | 1,500 | 900 |
| 2036 | | | 2,447 | 1,800 | 975 |
| 2037 | | | 2,575 | 2,100 | 1,125 |
| 2038 | | | 2,725 | 2,400 | 1,275 |
| 2039 | | | 2,875 | 2,600 | 1,425 |
| 2040 | | | 3,025 | 2,800 | 1,500 |

[5] Assumes retirement of coal gasification or implementation of carbon capture utilization and storage at Edwardsport in 2035

SECTION III

# RESOURCE PLANNING PROCESS, METHODS & TOOLS

Duke Energy Indiana files an IRP approximately every three years with the Indiana Utility Regulatory Commission.[1] The IRP includes analysis of firm electric loads, supply-side and demand-side resources, and environmental compliance measures associated with the Duke Energy Indiana service territory.

The final product is a twenty-year plan to safely, reliably, efficiently, and cost-effectively meet electric system demand taking cost, risk, and uncertainty into consideration, as required by 170 IAC 4-7.

[1] Duke Energy Indiana last IRP was due on November 1, 2018; however, an extension was granted until July 1, 2019. This IRP was due November 1, 2021, and an extension was granted to December 15, 2021. The next IRP is scheduled for November 1, 2024.

This section describes the process, methods and tools Duke Energy Indiana used to develop the IRP. This includes the following:

- **Forecasts - development of the long-term quantitative forecasts of load, fuel prices, and other variables that could affect resource decisions;**
- **Models - descriptions of the model used to develop power prices, expansion plans and production cost and how they are used;**
- **Technology Screen - discussion of the technology screening process by which resource types are determined to be eligible or ineligible for consideration in the development of future portolios;**
- **Scenario Planning - discussion of scenario planning and how uncertainty and risk are dealt with when developing the IRP;**
- **Stakeholder Process - description of the stakeholder process leading up to the submittal of this IRP; and**
- **Future Improvements - discussion of potential improvements that could be made to the IRP tools or process in the future.**

This section is limited to a discussion of methods, processes, and tools. For the actual forecasts, scenarios, and portfolios used in this IRP, please see Section IV: Duke Energy Indiana in the Future and Section V: Candidate Resource Portfolios. Additional technical details about the forecasts used in this IRP are available in the appendix.

## A. FORECASTING METHODS

## LOAD FORECASTING

The load forecast is one of the most important parts of the IRP process because customer demand provides the basis for the resources and plans chosen to supply the load. Electric energy and peak demand forecasts are prepared each year as part of the planning process by a staff that is shared among Duke Energy Corp. (Duke Energy) affiliated utilities. Each affiliated utility utilizes the same methodology. However, Duke Energy does not perform joint load forecasts among affiliated utility companies as each forecast is prepared independently.

The general load forecasting framework includes a national economic forecast, a service area economic forecast, and the electric load model. The economic forecasts include projections of economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, income, etc. Moody's Analytics, a leading national economic consulting firm, provides the histories and forecasts of key economic and demographic variables for the forecast model. The economic forecast is used together with the energy and peak demand models to produce the electric load forecast. A triennial customer survey was conducted in 2019; the next survey has been scheduled for 2022.

Independent forecasts for EV (Electric Vehicle) and PV (Rooftop Solar Distributed Energy Resources) are added to the "baseline" forecast. The EV and PV forecasts are developed by Duke Energy's Distributed Energy Technology Planning & Forecasting Department. These are generally added to the forecast without modification.

High and low electric forecasts were produced for this IRP. The low forecast is approximately 1% below the submitted forecast, while the high case starts at 1% higher in 2021 and growing to a 6.1% increase in 2040. For a discussion on how the high and low scenarios were developed, please see Appendix B.

In this IRP, based on stakeholder feedback, Duke Energy Indiana has begun to analyze how a climate change scenario would impact the load forecast. To perform this function, we included a measure of humidity in our weather data. Our Meteorology department created a weather data set based on the Intergovernmental Panel on Climate Change's (IPCC) Representative Concentration Pathway (RCP) of 4.5, which is considered an "intermediate scenario" by the IPCC, which included dry bulb temperature and dew point temperature. From this load forecasting staff created a Temperature Humidity Index degree dataset from which a heating degree and cooling degree day dataset was created and utilized in the climate change analysis. There was not a material impact on the forecast, the RCP 4.5 scenario increases temperatures approximately 2.5 degrees Fahrenheit (1.4 degrees Celsius) in the 2046 – 2065 time period, increasing to approximately 3.6 degrees Fahrenheit (1.8 degrees Celsius) in the 2081 – 2100 time period. It is less impactful during the IRP timeframe, as raising the temperature assumed in the forecast by about a degree has little impact. Future scenarios may include incorporating a more aggressive temperature pathway and possibly some non-weather factors. Climatology and climate change occur over very long terms, and may prove elusive incorporating into the, relatively, near term of a 20-year forecast.

Other inputs into the electric load forecast are behind-the-meter rooftop solar generation and electric vehicle (EV) charging load. Rooftop solar adoptions are expected to increase over the planning horizon due to declining technology costs and will continue to reduce served load. At the same time, EV adoptions are forecasted to increase steadily and additional load will be added to the system as a result. While EV load has been minimal to date (less than 0.05% of total load), projections have EV adoptions increasing greatly over the planning horizon. However, in the current load forecast, the impact of roof-top solar and electric vehicles on summer peak demand essentially offset each other, while winter peak demand increases as EVs are expected to charge when solar is less available during winter months. Load also slightly increases, as energy from electric vehicles out paces energy reduction from roof-top solar over the planning horizon.

Energy sales projections are prepared for the residential, commercial, industrial, street lighting, and public authority sectors. Sales projections and electric system losses are combined to produce a net energy forecast. These forecasts provide the starting point for the development of the IRP. For additional technical details and data, please see Appendix B.

Retail sales are expected to increase by 5,340 GWH over 2020, with a compound annual growth rate (CAGR) of 0.9%. By class:

| | | |
|---|---|---|
| Residential | 2,555 GWH | 1.2% CAGR |
| Commercial | 1,093 GWH | 0.8 CAGR |
| Industrial | 1,581 GWH | 0.7% CAGR |
| Other | 111 GWH | 0.3 CAGR |

Over the timeframe of the forecast, electric vehicles are expected to add a total of 1,375 GWH, while customer solar installations are expected to reduce load by 283 GWH and utility sponsored energy efficiency (UEE) is expected to reduce load by 1,250 GWH. This is a net reduction of 158 GWH or (0.5%) of load in 2041. For annual impacts see Appendix B.

## FORECASTING FUEL PRICES

The Company uses a combination of observable forward market prices and long-term commodity price fundamentals to develop coal and gas price forecasts. The former incorporate data from public exchanges including NYMEX, as well as fuel contracts and price quotes from fuel providers in response to regular Duke Energy fuel supply requests for proposals. The long-term fundamental fuels forecast is a proprietary product developed by IHS Markit Ltd., a leading energy consulting firm[2]. Fuel price forecasts provided by IHS are based on granular, integrated supply/demand modeling using fuel production costs and end-user consumption. The Duke Energy long-term fundamental forecast is approved annually by Duke Energy's leadership for use in all long-term planning studies and project evaluations.

The development of plausible high and low-price fuel forecasts is necessary to enable creation of a range of future scenarios for long-range resource planning.  To accomplish this, the Company's long-term fundamental fuel forecasts were adjusted using forecast factors from the Energy Information Administration's Annual Energy Outlook (AEO).  The forecast factors used for low fuel price development are from the AEO 2021 High Oil and Gas Supply Case and the factors for high fuel price development are from the AEO 2021 Low Oil and Gas Supply Case. These high and low fuel forecasts will be shown in greater detail in the scenario descriptions in Section IV of this Document.

[2] This content is extracted from the IHS Markit North American Power, Gas, Coal and Renewables service and was developed as part of an ongoing subscription service. No part of this content was developed for or is meant to reflect a specific endorsement of a policy or regulatory outcome. The use of this content was approved in advance by IHS Markit. Any further use or redistribution of this content is strictly prohibited a without written permission by IHS Markit. Copyright 2021, all rights reserved.

## FUEL SUPPLY CONSIDERATIONS

Duke Energy Indiana generates energy to serve its customers through a diverse mix of fuels consisting primarily of coal, syngas, natural gas, and fuel oil; it also participates in the MISO power market, which encompasses a variety of generation sources in parts of 15 U.S. states and the Canadian province of Manitoba. The Company continues to generate a majority of its energy using coal, with usage dictated by the relative prices of coal as compared to the fuel alternatives in the economic dispatch process.

## COAL

Over 84% of Duke Energy Indiana's total energy is generated from burning or gasifying coal. In evaluating the purchase of coal, the Fuels Department considers three primary factors: (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, and the evaluated economic impacts of the coal quality on station operations.

To aid in fuel supply reliability, fuel procurement policies (such as contracted tons to burn ratios or inventory target levels) help guide decisions on when the Fuels Department should enter the market to procure certain quantities and types of fuel. These policies are viewed in the context of economic and market forecasts and probabilistic dispatch models to collectively provide the Company with a five-year strategy for fuel purchasing. The strategy provides a guide to meet the goal of having a reliable supply of low cost fuel.

To enhance fuel supply reliability and mitigate supply risk, Duke Energy Indiana purchases coal from multiple mines in the geographic area of our 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, following the past several years of steep declines in coal generation, the financial health of the region's coal suppliers has declined, limiting suppliers operational flexibility, causing the Company to actively evaluate coal supplies from other regions. In 2020, over 97% of the coal supplied to base load stations were under long-term coal contracts supplied by Indiana mines.

Prior to entering commitments for greater than one year with coal suppliers, the Company evaluates the financial stability, performance history and overall reputation of potential suppliers. By entering into longer term commitments with suppliers, Duke Energy Indiana further protects itself from risk of insufficient coal availability while also giving suppliers the needed financial stability to allow them to make capital investments in the mines and hire the labor force. If the Company were to try to purchase significant portions of its requirements on the short-term open market, the Company likely would have severe difficulties in finding sufficient coal for purchase to meet its needs due to the inability of the mines to increase production to accommodate - 9-12 million annual tons in such a short timeframe.

The current Duke Energy Indiana supply portfolio includes two term coal supply agreements and the Company is actively engaged with suppliers to complete an additional three term transactions for deliveries through 2024. Duke Energy Indiana fills out the remainder of its coal needs with spot coal purchases. The current Duke Energy Indiana supply portfolio includes eight spot coal supply agreements for delivery over the balance of 2021 and the first quarter of 2022. Spot coal purchases are used to 1) take advantage of changing market conditions that may lead to low-priced incremental tonnage or limit exposure to rising market prices, 2) test new coal supplies, and 3) supplement coal supplies during periods of increased demand for generation or during contract delivery disruptions.

Under both term and spot contracts, the Company buys coal at the mine. Thus, the contracts do not restrict the Company's ability to move the coal to the various Duke Energy Indiana coal-fired generating stations as necessary to meet generation requirements. This arrangement allows for greater flexibility in meeting fluctuations in generating demand and any supply or transportation disruptions.

## NATURAL GAS

The use of natural gas by Duke Energy Indiana for electric generating purposes has generally been limited to Combustion Turbine (CT) and Combined Cycle (CC) applications. Firm natural gas supply is currently purchased in the spot market under an Asset Management Agreement and delivered firm or under a North American Energy Standards Board (NAESB) 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 deliverability to its gas generation portfolio. Duke Energy Indiana has the following firm transportation contracts: (1) Midwestern Gas pipeline for gas delivery to Edwardsport, Vermillion, and Wheatland, and 2) Panhandle Eastern Pipeline for delivery to Noblesville.

Duke Energy Indiana hedges up to 50% of its natural gas exposure in the summer period and up to 100% in the winter period using a combination of monthly NYMEX swaps and other financial products to mitigate monthly and daily price volatility. New CCs assume gas is being delivered via TETCO M2 pipeline from Marcellus Shale and includes the interstate and intrastate firm transportation rates. CTs are dual fueled with primarily interruptible gas and oil as a backup.

## HYDROGEN

Hydrogen ($H_2$) used as fuel is not viable today in the volumes required for power generation and was not used as a primary fuel in the 2021 IRP. Turbine manufacturers state that existing turbines have the ability to blend approximately 30% by volume today and project by 2030, will have the ability to be fire 100% $H_2$. In some of the deep carbonization portfolios, which required significant $CO_2$ reductions by 2035, $H_2$ was included as a fuel option for new CTs to provide a means to meet these aggressive targets. The price assumed was based on significant technology improvements to electrolysis, but did not address how $H_2$ would be delivered or self-generated. There is a lot of focus in the industry on the potential of $H_2$ as a fuel source and the Company will continue to monitor advancements as they occur.

## OIL

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

## FORECASTING POWER PRICES

As with fuel prices, 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, scenario specific carbon tax assumptions, technology assumptions, resource assumptions, and use of Horizon Energy's National Database which provides the existing MISO resource mix. The Company used Horizon Energy's database within EnCompass to develop scenario specific expansion plans for all of the Midcontinent Independent System Operator (MISO) service territory. 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 regards to fuel, carbon, and load assumptions.

## FORECASTING PRICES FOR CARBON EMISSIONS

In the current legislative/regulatory environment it is very difficult to project what a carbon-constrained future will look like. However, the Company believes that a constraint or price on carbon is likely to be imposed at some future date, so it is prudent to incorporate such a constraint into our resource planning. The Company evaluated multiple pathways for carbon reduction into the future. In the optimized $CO_2$ portfolios the Company used a $CO_2$ price of $5/ton starting in 2025 which escalates at $5/ton throughout the planning horizon. This price incentivizes continuous $CO_2$ reduction through increased renewable adoption, accelerated coal retirements, new natural gas generation and longer-term emerging generation options. For purposes of the PVRR and rate impact calculations, the Company assumed that the effects of carbon regulation are included, but would not include an explicit carbon tax that would be paid by customers. In addition to a specific carbon price, several stakeholders had portfolios with specific $CO_2$ emission limits which was evaluated as a $CO_2$ mass cap timeseries.

## FORECASTING CAPITAL COSTS

## TRADITIONAL RESOURCES

Duke Energy, in conjunction with third party vendors, developed capital cost projections for all generation technologies included in the IRP evaluation. Technology specific escalation rates for gas and nuclear generation technologies were derived from the Energy Information Administration (EIA) 2021 AEO. Wind, solar and storage capital costs were projected to decline over a 10-year period and then escalated at their technology specific rate for the remainder of the planning horizon. In addition to declining prices, solar costs include an investment tax credit extension through 2025, and assumes a tax equity partner which provides for more efficient financing.

Sensitivities were performed on the capital costs of solar, as well as natural gas plants. The solar capital cost sensitivity lowered the cost of solar based on the Company's recent Request For Information (RFI) data for renewables and storage. The median value of the RFI solar projects was used because it provided the greatest reduction in cost when compared to an average or weighted average (weighted based on installed Megawatts (MW)). The reduction in capital costs was rounded up to 15%. The results of this sensitivity showed how solar was incentivized to be built earlier than the base optimized runs. The natural gas capital cost sensitivity increased the cost of natural gas plants by 20% to determine the impact on the expansion plans. In the scenario without carbon regulation – the 2x1 J CC was delayed by six years compared to the base optimized expansion plan. In the scenario with carbon regulation – there is no impact on the build year of the 2x1 J CC. This is due to the economic advantage of reducing carbon emissions by retiring coal, while also satisfying energy and capacity needs. See Appendix C for all capital cost projections.

### RENEWABLES AND ENERGY STORAGE

Solar PV and storage capital costs were estimated over a ten-year period based on third party proprietary engineering studies. Solar PV and energy storage capital costs are projected to continue to decline over the next decade, although solar PV may see near-term costs increases due to supply chain constraints and material cost inflation. After ten years, 2021 EIA AEO cost projections are blended with the third-party engineering study to determine estimated capital costs through 2050. Although supply chain constraints could become an issue with increased deployment of lithium ion battery storage, due to the relative immaturity of the technology, a significant decrease in capital costs is expected over the next decade. In order to maintain the required energy output of the battery storage system over the life of the asset, lithium ion battery storage costs assume augmentation is required to account for degradation of the battery cells. Finally, additional energy storage was included due to the expected depth of discharge limit of 90% of the total energy.

## B. PLANNING MODELS

For this IRP, Duke Energy Indiana switched to the EnCompass planning model. Throughout the selection process, Duke Energy met with interested stakeholders to solicit input on the various modeling options before ultimately selecting EnCompass. EnCompass is a power planning software designed for making optimal energy resource decisions. EnCompass' economic optimization model is used to develop portfolios while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional generating units such as CTs, CCs, renewable resources and storage. EnCompass uses mixed integer and linear programming optimization procedures to select the most economic expansion plan based on minimizing Present Value Revenue Requirements (PVRR). The model calculates the cost and reliability effects of modifying the load with DSM programs or adding supply-side resources to the system.

EnCompass was also used as a detailed production-cost model for simulation of the optimal operation of an electric utility's generation facilities. EnCompass use simplification techniques in order to make resource selection decisions in the development of expansion plans. The production cost simulations in EnCompass use the expansion plans to determine the optimal hourly operation for each portfolio. The production cost simulations provide more detailed and accurate data when analyzing the economics and reliability of a portfolios. Key EnCompass inputs include generating unit data, fuel data, load data, transaction data, Demand-Side Management (DSM) data, emission and allowance cost data, and utility-specific system operating data.

EnCompass was used to develop MISO power prices. Each specific scenario expansion plan was simulated using Horizon Energy's national database to determine the optimal resource mix. Production cost was simulated for each expansion plan to calculate hourly power prices.

## C. RESOURCE SCREENING

### SUPPLY-SIDE RESOURCES

Supply-side resources may include existing generating units; repowering options for these units; potential bilateral power purchases from other utilities, Independent Power Producers (IPPs) and combined heat and power applications; short-term energy and capacity transactions within the MISO market; new utility-built generating units (conventional, advanced technologies, and renewables), energy storage and storage paired with solar. When considering these resources for inclusion in the portfolio, the Company assesses their technical feasibility, commercial availability, fuel availability and price, useful life or length of contract, construction or implementation lead time, capital cost, operations and maintenance (O&M) cost, reliability, and environmental impacts.

The first step in the screening process for supply-side resources is a technical screening to eliminate from consideration those technologies that are not both technically and commercially available to the Company. Also excluded from further consideration are technologies that are not feasible, available or economically viable in or near the Duke Energy Indiana service territory. Supply-side resources not excluded for availability reasons are included as potential options in the economic optimization modeling process using the EnCompass model.

Additional details on the screening of supply-side resources can be found in Appendix C.

## RETIREMENT ANALYSIS

Generating unit retirements are selected in the EnCompass model using a five-step process. This is necessary because the fixed cost inputs in EnCompass are a main driver for retirement decisions. The steps include three EnCompass runs, an intermediate step where initial ongoing Capital Expenditures (CAPEX) and fixed cost values are calculated, and a post-process step in which the final ongoing CAPEX and fixed cost values are recalculated to account for the declining costs leading to retirements. Ongoing CAPEX and fixed costs are calculated using an in-house tool.

1. An initial EnCompass run is conducted in which the system is modeled over the planning period with no units eligible for retirement. The key output of this run is the capacity factors, heat inputs, variable costs, service hours and $CO_2$ emissions of each unit in each year of the planning period.
2. An in-house spreadsheet is used to forecast future maintenance cycles, capital expenditures for maintenance, and fixed operating costs, all based the outputs from the initial EnCompass run. The ongoing CAPEX and fixed cost forecasts are aggregated together for each unit and are used as an input for a second EnCompass run.
3. The second EnCompass run is conducted using the aggregated ongoing CAPEX and fixed cost forecasts from Step 2 as an input. Economic retirements are allowed within EnCompass. All other inputs are identical to the initial run. In this step, EnCompass selects units for retirement when the present value of future fixed and variable costs exceeds the costs associated with retirement and replacement. That is, if the costs that can be avoided by retiring a unit are greater than the cost of running the system without that unit (including the cost of replacement), then the unit is retired.

4. The third EnCompass run is an hourly production cost simulation where the aggregated ongoing CAPEX and fixed costs are removed from the model. This simulation uses the expansion plan with retirements from step 3 to simulate hourly operation of the portfolio. The reason the aggregated ongoing CAPEX and fixed costs are removed is due to the need of accounting for CAPEX and fixed costs separately. These costs are accounted for in step 5.
5. Similar to step 2, the outputs from step 4 are used as inputs into the in-house spreadsheet to recalculate the ongoing CAPEX and fixed costs to account for the declining costs leading to retirement. These costs are then added to our post-process calculations outside of the model.

Note that the cost of replacing a unit is never as simple as a one-for-one replacement of megawatts based on capital cost. Costs may include new capacity from a variety of sources as well as changes to the dispatch of existing units, and these changes may be realized over multiple years. Furthermore, total replacement capacity will not equal the capacity of the retiring unit due to differences in unit size and changes to peak load over time. The EnCompass model considers all of these factors and their interdependencies over the planning period when selecting resource retirements and additions.

## EDWARDSPORT IGCC

The retirement analysis considered multiple operating conditions for Duke Energy Indiana's newest coal plant, the Edwardsport Integrated Gasification Combined Cycle ("IGCC") plant. This analysis included three operating conditions: operating primarily on coal, conversion to operate exclusively on natural gas, and retirement of the entire plant. An additional stakeholder portfolio included an analysis of adding Carbon Capture Utilization and Storage (CCUS) to Edwardsport IGCC with the inclusion of associated 45Q tax credits.

## DEMAND-SIDE RESOURCES

## ENERGY EFFICIENCY

The Company received approval for its 2020-2023 Energy Efficiency (EE) portfolio under Cause No. 43955 DSM-8 and is currently implementing that portfolio. The EE forecasts used in development of the IRP are based on a combination of the portfolio approved in Cause No. 43955 DSM-8 along with future projections of energy savings potential provided in the recently completed Market Potential Study (MPS) for periods beyond 2023.

Duke Energy Indiana worked collaboratively with a third-party consultant, Resource Innovations (formerly Nexant), and stakeholders on an energy efficiency Market Potential Study, which included multiple scenarios for projecting future energy savings potential. Projected impacts from EE and demand response (DR) programs were developed in the MPS for a 25-year forecast period from 2021 through 2045.

In preparing the projected demand-side resource options available for selection in this IRP, the Company 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 by the IRP models. The energy savings in the EE bundles were modeled based on the currently approved EE portfolio and two of the four MPS scenarios. The two scenarios were selected in collaboration with the EE Oversight Board due to having the lowest levelized cost per MWh for EE savings.

In order to provide the model with increased granularity of options in the near term, the first two sets of bundles were developed with a duration of three years each for the periods 2021-23 and 2024-26. These three-year periods correspond with the current and upcoming EE filings. In order to reduce the computational burden on the IRP models, the next three sets of bundles were developed with a duration of 8 years each for the periods 2027-34, 2035-2042 and 2043-50. In order to reduce the computational burden on the IRP models, the next three sets of bundles were analyzed with a duration of 8 years for the periods 2027-34, 2035-2042 and 2043-2050. Bundles beyond the MPS were defined by extrapolation for the final 5 years. The annual energy savings and associated cost of each bundle were provided by either the currently approved EE Portfolio (2021-2023) or the Market Potential Study (2024-2045). The bundles in the 2040s were used to minimize potential end effects.

The set of bundles selected in our preferred portfolio includes an enhanced level of energy efficiency savings as compared to existing programs, generating additional cumulative energy savings of about 20% over the next 25 years – and reducing average annual electric sales by over 1%. Further details of the methodology used to forecast energy efficiency and energy savings projections are included in Appendix D.

## DEMAND RESPONSE

Similar to EE, demand response was modeled as selectable bundles and included continuation of existing programs as well as three additional DR bundles that include the additional cost to entice greater participation in our DR program.

The preferred portfolio also includes continued year-over-year demand response of approximately 600 megawatts, reflecting its current special contract and robust PowerShare® program continuing during the 20-year period. We will continue to monitor potential changes to demand response policy via FERC's Order No. 2222. MISO is currently developing rules for how distributed generation and demand response may be able to participate in the wholesale market, with a proposal expected in mid-2022. We will follow this closely and update in future planning, as appropriate.

## D. SPECIFYING IRP OBJECTIVES

The purpose of this IRP is to define a robust strategy to furnish electric energy services to Duke Energy Indiana customers in a reliable, efficient, economic and increasingly clean manner in accordance with all applicable environmental regulations while remaining dynamic and adaptable to changing conditions. We use scenario planning and sensitivity analysis to address areas of regulatory, economic, environmental, and operating uncertainty. The triennial filing schedule allows the Company to monitor key sources of uncertainty and adjust the plan as necessary, thereby producing an IRP that represents the most reliable and economic path forward based upon robust analysis of emerging information.

Our long-term planning objective is to develop a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community) while maintaining the flexibility to adapt to changing conditions. At times, this involves striking a balance between competing objectives.

## DETERMINING A PLANNING RESERVE MARGIN

We address system reliability and resource adequacy in the planning process by targeting an appropriate planning reserve margin for use in our IRP models. Duke Energy Indiana's reserve requirements are driven by ReliabilityFirst, which has adopted a Resource Planning Reserve Requirement Standard that the Loss of Load Expectation (LOLE) due to resource inadequacy cannot exceed one day in ten years (0.1 day per year). This Standard is applicable to the Planning Coordinator, which is MISO for Duke Energy Indiana.

Planning Reserve Margin (PRM) can be expressed on either an ICAP (*i.e.*, installed capacity) or UCAP (*i.e.*, unforced capacity) basis. The required MISO $PRM_{ICAP}$ is translated to $PRM_{UCAP}$ using the MISO system average equivalent forced outage rate excluding events outside of management control ($XEFOR_d$)[3] and assigned to each Load Serving Entity (LSE) on a UCAP basis. For the 2020/2021 Planning Year, the Company is required to meet a $PRM_{UCAP}$ of 9.6%.

In this IRP, Duke Energy Indiana's IRP models utilize the UCAP unit ratings to estimate dispatch. Overtime, it is expected that Duke Energy Indiana may move from a summer peaking utility to a winter planning utility. As more renewable energy, in particular solar resources, are added to the MISO and Duke Energy Indiana systems, the solar is not available in the winter period. As such, winter peaks become more constrained.

MISO is undergoing a stakeholder process on resource adequacy that has been filed at FERC to change to a four-season capacity market and make adjustments to the capacity

[3] $PRM_{UCAP} = (1 – \text{MISO Average } XEFOR_d)(1 + PRM_{ICAP}) – 1$

accreditation for traditional generating units. The specifics of the proposal were under development as the IRP progressed, and were only recently filed at FERC. While we do know there will be impacts that could require additional capacity resources, Duke Energy Indiana does not currently have clarity around the specific impacts to our resource requirements such that it could be included in the modeling of this IRP.

However, our analysis did review the all portfolios to ensure each met the current reserve margin requirement in both the summer and winter seasons, recognizing our duty to ensure peak load is met. Duke Energy Indiana will continue to closely monitor the potential MISO construct changes and provide updates in future IRPs to reflect the changes that are ultimately implemented.

## E. SCENARIO DEVELOPMENT & OPTIMIZED PORTFOLIOS

The basic method for developing an IRP is to predict what the future will be like over the 20-year planning horizon and then design the best resource portfolio possible given that vision. The major challenges are the obvious fact that it is impossible to perfectly forecast the future, and the perhaps less obvious fact that the notion of what is “best” can be difficult to define. We use scenario analysis to explore how different resource portfolios might perform under a variety of future conditions, and to examine the tradeoffs that may need to be considered among potentially competing objectives.

A scenario in this context is a formalized set of assumptions about the future. We do not try to assess every possible future that could unfold over the planning horizon. That would be futile. Instead we describe a small, manageable set of potential versions of the future that we believe captures the full range of plausible possibilities. Each of these is a scenario.

It is important to note that the factors that go into describing a scenario are external to the Company. These include market structures and prices; energy demand and peak load; federal, state, and local policy environments; and so on. In this context, scenarios include no assumptions about Company actions or resource portfolio decisions. Potential Duke Energy Indiana plans and decisions are evaluated within and across the various scenarios.

The steps involved in scenario development are:

1. ***Define the planning objectives and scope of analysis.*** The scope of the analysis is largely determined by Indiana IRP rules. The geographic boundary coincides with the Duke Energy Indiana service territory and areas that immediately influence factors in that territory, and the time horizon is the 20-year IRP planning window. The planning objectives are determined by a mix of state and MISO rules governing reliability and cost-effectiveness, and input from stakeholders.
2. ***Describe the fundamental trends affecting the Company's ability to meet the agreed-upon objectives.*** These trends could include regulatory, economic, industry, or technological factors, among others.
3. ***Identify key sources of uncertainty.*** These should be factors that are very difficult to forecast and that will have a significant impact on portfolio choices. Selection of these variables will be informed by the trends described in Step 2, and the scenario framework will be constructed around them. Factors that are important but that can be forecast with greater confidence will also be considered, but should not be the focus when developing scenarios.

4. ***Describe visions for potential futures in qualitative terms*****.** These narratives, which should reference the trends and uncertainties explored in the previous steps, will form the central themes for the different scenarios.
5. ***Describe the current conditions that are the baseline for planning for the future.*** The world as it exists in the present is the starting point for all scenarios, and all forecasts are informed by recent history. The further we look into the future, the more the different scenarios diverge.
6. ***Develop quantitative sets of expectations for the future of the market, regulatory, and technical environments in which the company operates.*** In order to perform the quantitative analysis that provides the foundation for selecting the preferred portfolio, each scenario must be fully described in quantitative terms. That is, each scenario must have a quantitative forecast for each of the input variables used in the analysis. Forecasts must be consistent within scenarios and with the scenario narratives described in Step 4 for the scenarios to be valid. For instance, all else being equal, a scenario that assumes rapid increases in natural gas prices and also the widespread adoption of gas-fired generation is probably not plausible.
7. ***Review scenarios with stakeholders to confirm completeness.*** Consult stakeholders in the planning process to obtain feedback on whether the set of scenarios covers the full range of plausible futures that needs to be addressed. Add, subtract, or modify scenarios if necessary.

The stakeholder discussions in this IRP resulted in four distinct scenarios: 1) Reference case with no $CO_2$ regulation; 2) Reference case with $CO_2$ Regulation; 3) High gas prices; and 4) Low gas prices.

Once the set of scenarios is fully described and each scenario has a complete set of forecasted input variables, we use the quantitative models to design the "optimized" resource portfolio for each scenario. In other words, taking the scenarios one at a time, we plug the full set of input variables into EnCompass (described above) and the model determines which generating resources should be added or retired and when those changes should occur, given the future as defined in the scenario under consideration. The EnCompass model solves for the least cost resource portfolio that meets the planning reserve margin requirement, as measured by the present value of revenue requirements (PVRR) over the 20-year planning period. The resulting resource mix for each scenario is referred to as an optimized portfolio because it is selected entirely by the model.

Although we call these portfolios "optimized," we shouldn't immediately assume that one of them is likely to be the preferred portfolio selected in the IRP. For one thing, each optimized portfolio is created in the context of a specific scenario and may perform poorly under future conditions that differ from the scenario for which it is designed. Second, while the model selects the portfolio that minimizes future costs, it does not help us make judgements about other factors (fuel diversity, environmental impacts, etc.) that may affect the desirability of the resource mix. Finally, the model does not account for many feedbacks that occur in the real world, where resource choices made today may influence the future state of the variables we treat as inputs. So, while the optimized portfolios are a vital first step in the analysis that provide important insight into the resource mixes that may be preferable under different future conditions, further analysis is needed before the preferred portfolio can be selected.

## F. HYBRID AND STAKEHOLDER PORTFOLIOS, SENSITIVITIES & SELECTING THE PREFERRED PORTFOLIO

### MODELING OF PORTFOLIOS

After developing the optimized portfolio for each of the scenarios under consideration, the next step is to assess their strengths and weaknesses to understand how improvements could be made. This is done by modeling how each optimized portfolio would perform under the scenarios for which it was not specifically designed, and then by performing sensitivity analysis to see how portfolio performance is affected by changing a single assumption of interest while holding others constant.

The first step is to model all portfolio-scenario combinations in our production cost model, EnCompass (described above). Both the portfolio (resource mix) and the scenario (possible future in which that portfolio would exist) are inputs to EnCompass. The model output is a detailed estimate of how the resources in the portfolio would operate under that scenario. That includes an hour-by-hour account of how much energy each generator would produce, how much fuel of each type would be consumed, how much energy would be purchased from (or sold to) the MISO market, how many tons of carbon dioxide and other emissions would be produced, and what the total cost of operating that portfolio would be in each hour over the 20-year planning period. This allows us to understand how a given portfolio would operate under each of the scenarios we test, and what the strengths and weaknesses of each portfolio are. Understanding how portfolio performance changes as we change the scenario can also help highlight specific assumptions that we may wish to focus on for additional analysis.

## HYBRID AND STAKEHOLDER PORTFOLIOS

We use insights gained from review of the optimized portfolios to design a small number of alternative, or hybrid, portfolios where we aim to capture or build on the positive aspects of the optimized portfolios while minimizing their shortcomings. This could include, for example, adding more of a resource type that provides benefits that the model does not recognize, removing resources that perform well only under certain conditions, or diversifying the resource mix to reduce risk. We then run the hybrid portfolios through the production cost model to test how they would perform under each scenario and, if necessary, we may make additional adjustments to the alternatives to enhance their performance.

In this IRP, Duke Energy Indiana specified four hybrid portfolios: 1) Balanced Hybrid; 2) Renewables/CC Hybrid; 3) Renewables/CC/CT Hybrid; and 4) Renewables/CT Hybrid.

Stakeholder discussions also resulted in stakeholder inspired portfolios of resources. For instance, in this IRP, stakeholders indicated a desire for a portfolio that met President Biden's stated climate goal of net zero carbon emissions by 2035, and a lesser strict portfolio that reaches a 90% reduction by 2035. Other stakeholders worked with Duke Energy Indiana to specify portfolios that eventually became a Reliable Energy portfolio and an environmental focused portfolio. Finally, Duke Energy Indiana continues to work with a stakeholder to specify a scenario and portfolio that has deep decarbonization and rapid electrification throughout the U.S. After the stakeholder inspired portfolios are specified, we run each through the production cost model to test how they would perform under each scenario.

## SENSITIVITY ANALYSIS

After all the portfolios have been analyzed, we determine if there are other issues we would like to test. Focus on a single assumption is called sensitivity analysis. This goal is to assess the degree to which portfolio performance or composition would be affected by changing a single assumption that is of particular interest. For example, we may wonder how an increased load forecast would change the portfolio, or what lower renewable costs would do. In this IRP, we performed eight sensitivity analyses, many inspired by stakeholder discussions: 1) High load; 2) Low load; 3) Climate change load; 4) Request for Information (RFI) renewable costs; 5) Higher wind effective load carrying capability; 6) Higher capital costs for gas generation; 7) Upstream greenhouse gases; and 8) Social cost of carbon.

The results of the portfolio-scenario combinations and the sensitivity analysis provide us with information about how different resource mixes perform under different conditions and about how performance can vary if conditions change.

## DECISION CRITERIA

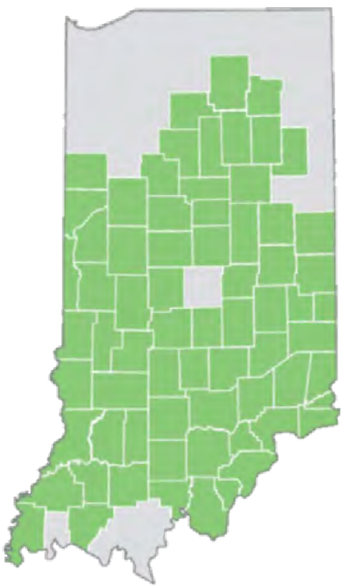
After Duke Energy Indiana specifies all the portfolios, models them, and performs the desired sensitivity modeling, we evaluate all the portfolios on certain decision criteria. In this IRP, Duke Energy Indiana looked to energy policy for the State of Indiana to develop its decision criteria. The 21st Century Task Force report released in November 19, 2020, made several findings, including "That the reliability, resilience, stability, affordability and environmental sustainability are the five key pillars of a state energy policy, and that one pillar cannot be addressed without impacting the other four."[4] Duke Energy Indiana supports this statement and as such, developed several metrics under the broad decision criteria of: 1) Reliability; 2) Resilience/Stability; 3) Affordability; 4) Environmental Sustainability; and 5) Portfolio Flexibility. The metrics can be found in Section VI, and included analysis such as market dependent risk, diversity, the five-year rate impact, $CO_2$ reductions, and how well a portfolio performed across all four scenarios.

Duke Energy Indiana then used its judgement and all the decision criteria to select a preferred portfolio that cost-effectively, reliably, and sustainably meets our customers' expected demand. The portfolio that performed well across all four scenarios and reasonably under all the decision criteria metrics was the Renewable/CC/CT Hybrid Portfolio.

[4] 21st Century Energy Policy Development Task Force, November 19, 2020 Report, p. 9.

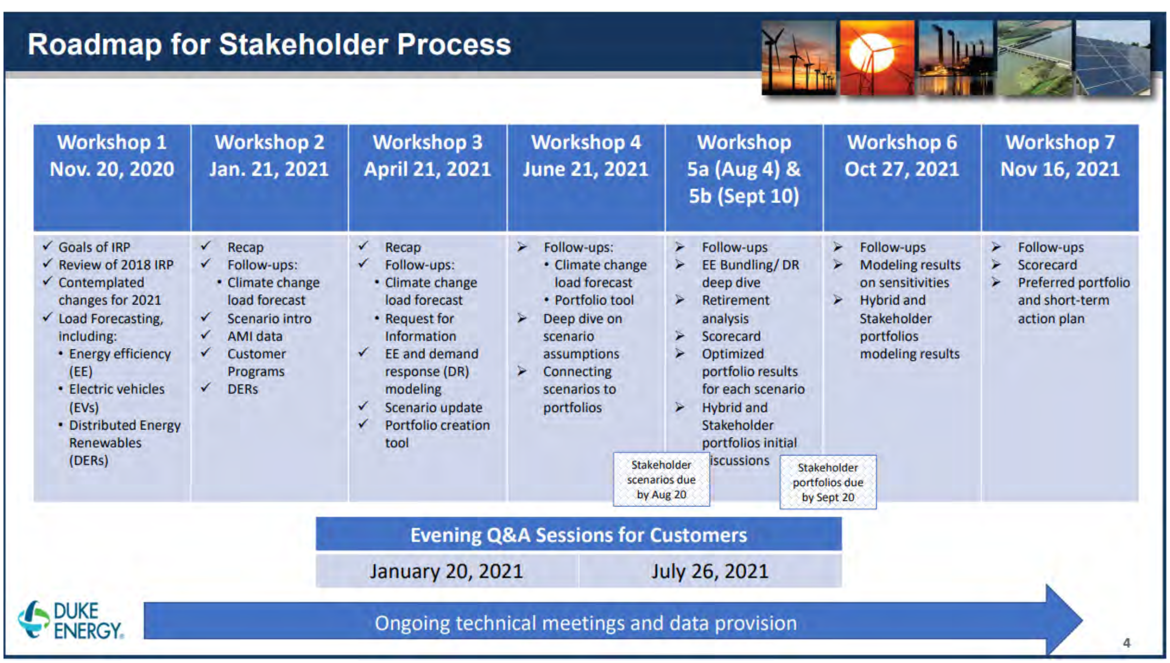
## G. STAKEHOLDER PROCESS

Prior to submitting the IRP, Duke Energy Indiana conducts a series of stakeholder meetings to discuss the IRP process and gather stakeholder input. Topics covered in the course of the stakeholder process include:



- **Background on the IRP process and scenario planning**
- **Discussion of the specific objectives for current IRP**
- **Overviews of specific scenarios under consideration for the current IRP**
- **Solicitation of stakeholder-proposed scenarios and feedback on Duke Energy Indiana-proposed scenarios**
- **Specific forecasts and model imputs for each scenario**
- **Review of Duke Energy Indiana-proposed resource portfolios and stakeholder-designed portfolios**
- **Preliminary modeling results and sensitivity analysis**
- **Final modeling results and presentation of the preferred portfolio**

Below is a detailed agenda for the eight stakeholder meetings:



Materials covered in this IRP and meeting summaries are included in Volume 2 and are posted on the Company's website at: https://www.duke-energy.com/home/products/in-2021-irp-stakeholder.

## H. FUTURE IMPROVEMENTS

With each IRP, the Company takes the lessons learned from pervious IRPs as well as from feedback from stakeholders, the Commission and Commission Staff. Between the submission of the 2021 IRP and the beginning of the 2024 IRP, the Company will continue to work with involved parties to identify specific improvements such as:

- Forecasted cost of new generation technologies
- Modeling methodologies
    - MISO level modeling such as forecasting reserve margins as well as a seasonal resource adequacy construct
    - Duke Energy Indiana level modeling such as the tradeoffs between various resource selection as well as more granular analysis of market purchases
- Incorporating more transmission planning perspectives as the Duke Energy Indiana and MISO fleet transitions
- Extreme weather analysis
- More comprehensive Green House Gas (GHG) analysis

SECTION III

# DUKE ENERGY INDIANA TODAY

## A. LOAD AND CUSTOMER CHARACTERISTICS

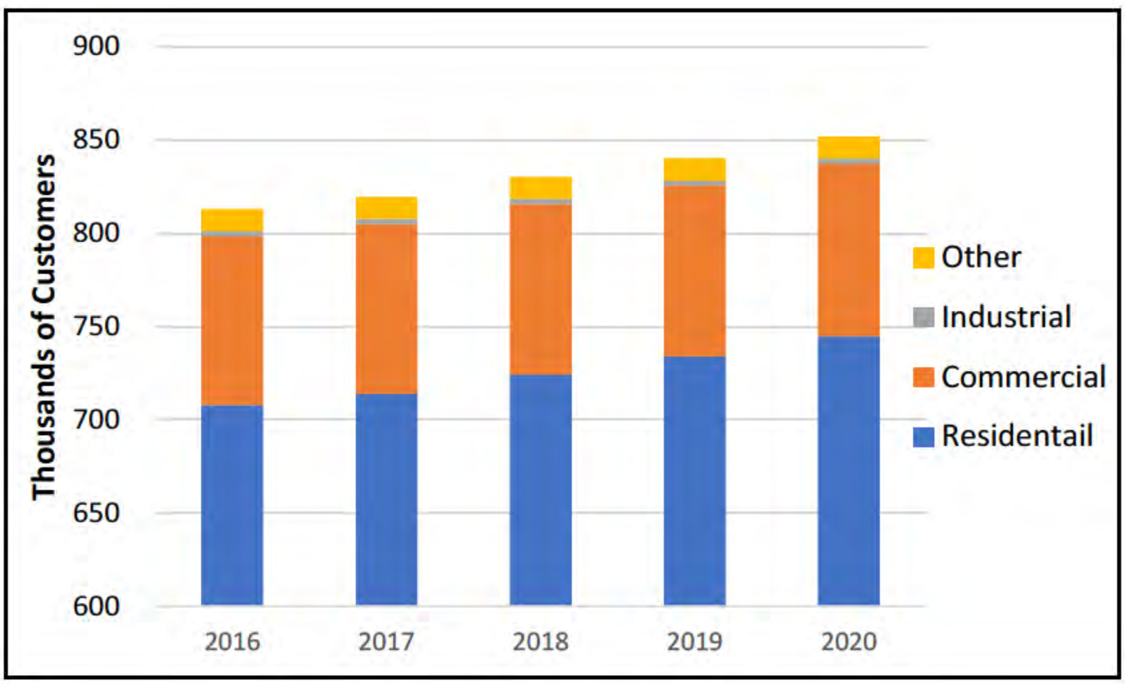
Duke Energy Indiana is Indiana's largest electric utility electric serving approximately 860,000 electric customers in 69 of Indiana's 92 counties covering North Central, Central, and Southern Indiana. Its service area spans 23,000 square miles and includes Bloomington, Terre Haute, Lafayette, and suburban areas near Indianapolis, Louisville and Cincinnati.

For the purposes of resource planning and load forecasting, customers are segmented into the following categories:

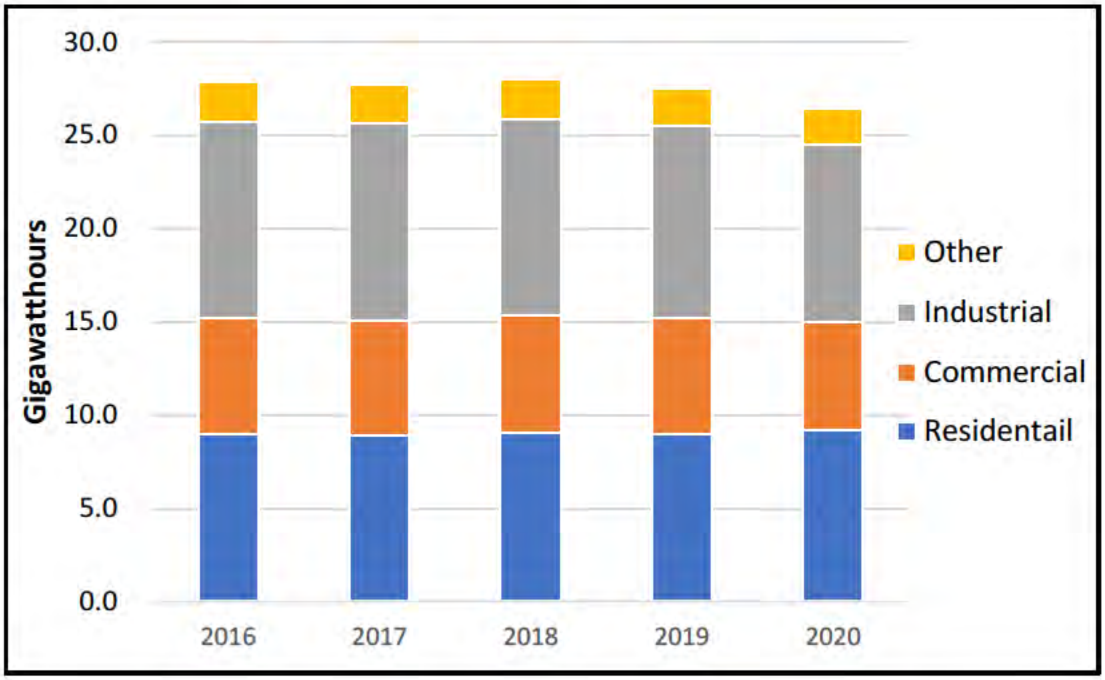

Additionally, Duke Energy Indiana provides power via wholesale contracts with several municipal and cooperative power providers. The number of retail customers in each category, historical retail energy sales by customer category, and historical peak demand and total energy sales, including wholesale, are displayed in the figures below. For additional detail on historical load, see Appendix B.

It should be noted that from a modeling standpoint, utility sponsored energy efficiency (UEE) is modeled as a resource. To do that and not double count UEE, it needs to be removed from the load forecast. That process includes removing historical UEE and then reforecasting load so that it only includes naturally occurring energy efficiency. Using this before UEE load forecast, UEE and other resources are then applied to serve customer load.

## FIGURE III.1
## HISTORICAL NUMBER OF RETAIL CUSTOMERS BY CATEGORY (ANNUAL AVERAGE)



## FIGURE III.2
## HISTORICAL RETAIL ENERGY SALES BY CUSTOMER CATEGORY (AFTER UTILITY ENERGY EFFICIENCY (UEE))



## FIGURE III.3
## HISTORICAL PEAK & WEATHER NORMALIZED DEMAND INCLUDING WHOLESALE (AFTER UEE)

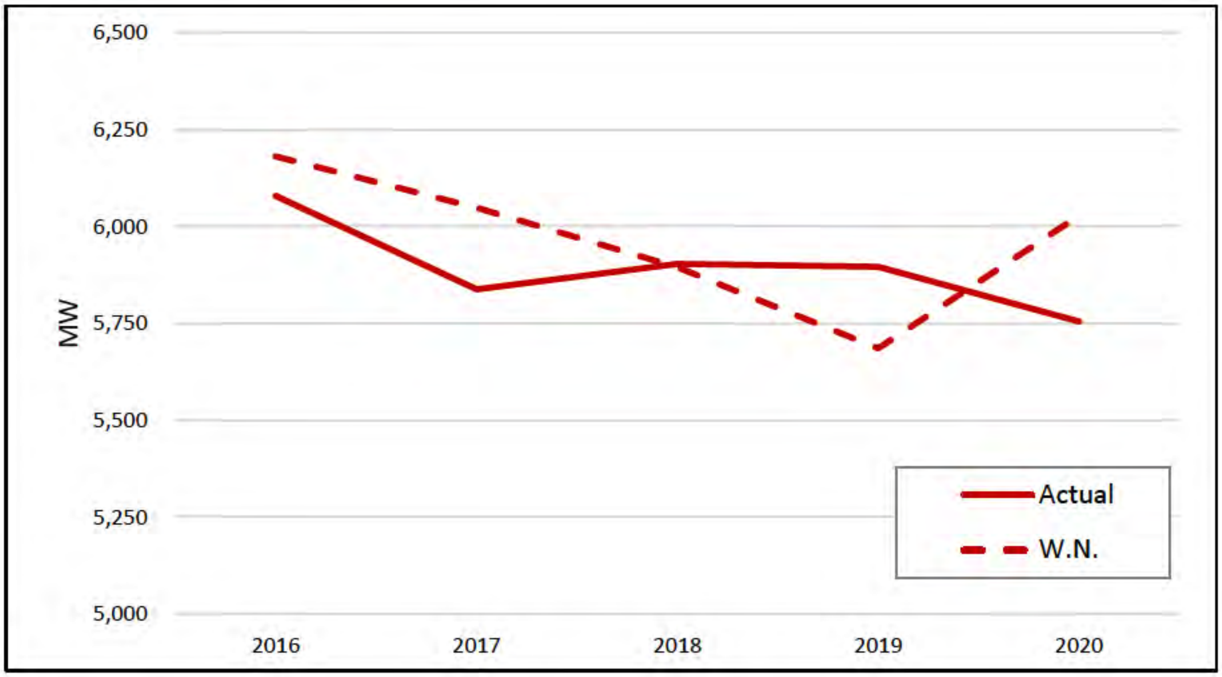
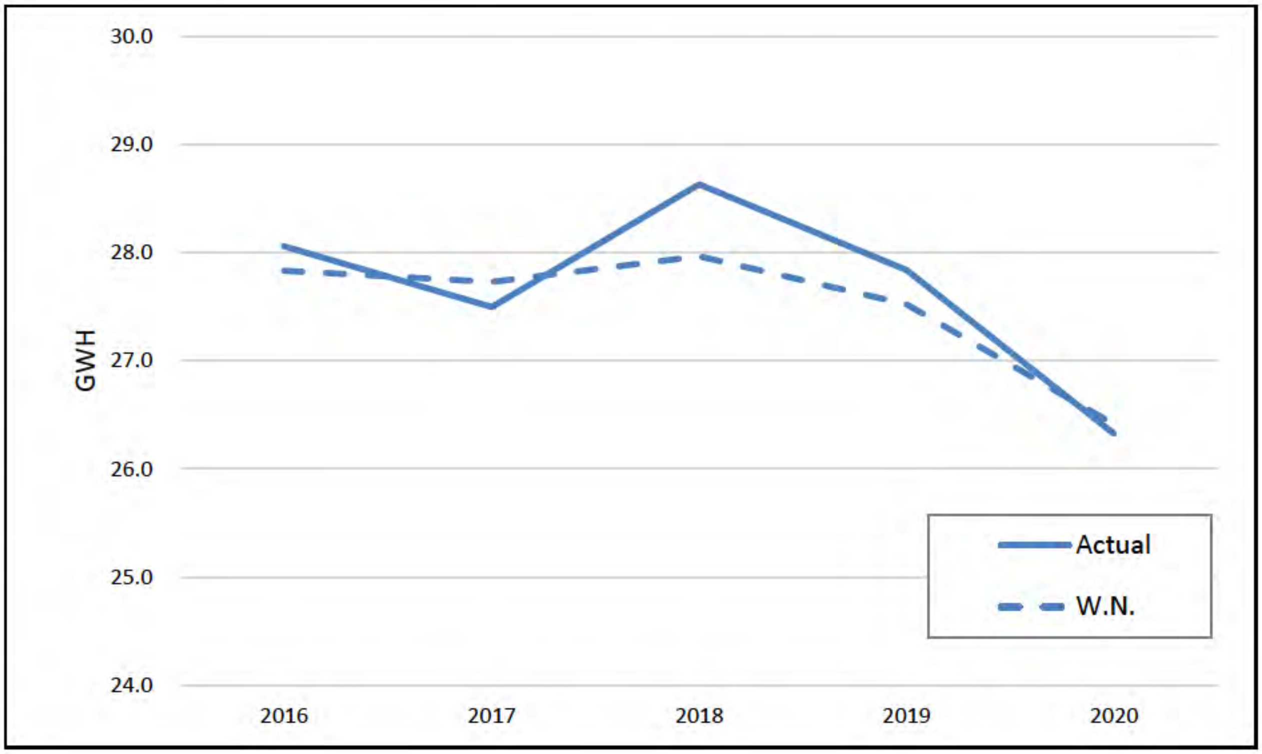


FIGURE III.4
HISTORICAL TOTAL AND WEATHERED NORMALIZED ENERGY SALES INCLUDING WHOLESALE (AFTER UEE)




## B. CURRENT GENERATING RESOURCE PORTFOLIO

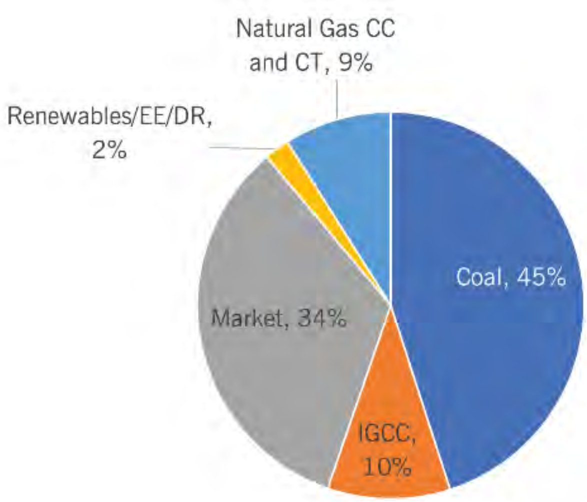
The total installed net summer generation capability owned or purchased by Duke Energy Indiana is currently 6,429 MW. This capacity consists of 3,817 MW of coal-fired steam capacity, 595 MW of syngas/natural gas combined cycle capacity, 264 MW of natural gas-fired CC capacity, 54 MW of hydroelectric capacity, 1,533 MW of natural gas-fired peaking capacity and 21 MW (11.4 MW contribution to peak) of owned solar photovoltaic (PV) capacity. Also included are power purchase agreements with Benton County Wind Farm (100 MW, with a 10 MW contribution to peak) and five contracted solar facilities totaling 24 MW with a 10.2 MW contribution to peak. Lastly, there are 10 MW of oil-fired CT capacity and 12 MW of storage.

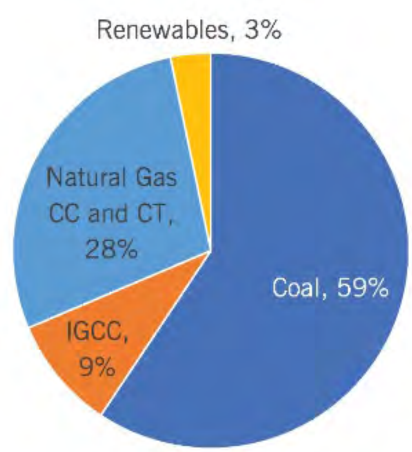
The coal-fired steam capacity consists of 7 units at two stations (Gibson and Cayuga). The syngas/natural gas combined cycle capacity is comprised of two syngas/natural gas-fired combustion turbines and one steam turbine at the Edwardsport Integrated Gasification Combined Cycle (IGCC) station. The CC 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 CTs at five stations (Cayuga, Henry County, Madison, Vermillion, and Wheatland). One of these natural gas-fired units has oil back-up. Duke Energy Indiana also provides steam service to one industrial customer from Cayuga, which reduces Duke Energy Indiana's net capability to serve electric load by approximately 20 MW. The solar capacity consists of 4 PV plants (Crane Naval Station, Camp Atterbury, Tippecanoe, B-Line Heights) as well as power purchase agreements with four 5 MW fixed-tilt PV facilities located near Brazil, West Terre Haute, Kokomo and Sullivan, Indiana and a 4 MW fixed-tilt PV facility near Staunton, Indiana. In addition, the Crane Naval Station and Camp Atterbury PV plants each have a 4 MW battery storage system, and there is a 5 MW stand-alone battery storage system at Nabb Substation.

The pie charts below depict Duke Energy Indiana's energy mix from the calendar year 2020 and the capacity mix for 2021. It should be noted that the onset of COVID-19 in 2020 reduced load and the cost of power, which resulted in the Company buying more power from the energy market than is typical. Taking advantage of lower market price is one way the

Company works to reduce costs to customers. Furthermore, in 2021, natural gas prices increased considerably and pushed up power prices; in response to this, the Company has reduced energy market purchases and increased generation as another way to protect customers and has shown that the coal fleet is a good hedge against increasing gas and power prices.

## FIGURE III.5
## HISTORICAL ENERGY AND CAPACITY MIX




## C. CURRENT DEMAND-SIDE PROGRAMS

Duke Energy Indiana has a long history associated with the implementation of energy efficiency (EE) and demand response (DR) programs. 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.

Implementing cost-effective EE and DR programs helps reduce overall long-term supply costs. Duke Energy Indiana's EE and DR programs are primarily selected for implementation based upon their cost-effectiveness; however, there may be programs, such as a low-income program, that are chosen for implementation due to desirability from an educational and/or social perspective.

## CURRENT ENERGY EFFICIENCY PROGRAMS

Duke Energy Indiana's current Energy Efficiency (EE) program portfolio was approved by the Commission in Cause No. 43955 – DSM8 for the periods 2021-2023 and contains the following set of programs described in greater detail in Appendix D:

## RESIDENTIAL PROGRAMS

- Smart $aver® Residential
    - HVAC Equipment
    - Attic Insulation and Air Sealing
    - Duct Sealing
    - Heat Pump Water Heater
    - Variable-Speed Pool Pump
    - Referral Channel
    - Specialty Lighting & other energy efficient products
    - Retail Instant Rebates

- Save Energy and Water Kit
- Low Income Neighborhood - Neighborhood Energy Saver Program
- Low Income Weatherization

- Multifamily Energy Efficiency Products & Services
- Residential Energy Assessments
- My Home Energy Report
- Energy Efficiency Education Program for Schools
- Power Manager® (Demand Response)
- Bring Your Own Thermostat (Demand Response)

## NON-RESIDENTIAL PROGRAMS

- Smart $aver® Non-Residential Incentive Program
    - Prescriptive Incentives
    - Custom Incentives
    - Performance Incentives
- Small Business Energy Saver
- Power Manager® for Business
- Public Efficiency Streetlighting

## CURRENT DEMAND RESPONSE PROGRAMS

In addition to the Residential Demand Response programs approved in Cause 43955 – DSM8, Duke Energy Indiana also offers the following Non-Residential Demand Response programs under its Rider 70 and other special contracts:

- PowerShare® CallOption

- Special Curtailment Contracts

## ADVANCED METERING INFRASTRUCTURE (AMI) AND SMART GRID TECHNOLOGIES

The availability and potential for advanced analytics around AMI data may lead to improved accuracy in the determination of customers' heating / water heating fuel types, identifying similar load shapes for customer comparison, and identifying equipment signatures for EE program design and enhancements. The availability and analysis of AMI data also may facilitate more constructive conversation around complex high bills and energy audits with more potential explanation around for load shape anomalies and seasonal changes.

Duke Energy Indiana is working to improve the use of Advanced Metering Infrastructure and Smart Grid technologies. The load research team is currently transitioning from a sample design process using data from less than 1% of customers to a near-total population approach using over 99% of our customers' data now that most customers have AMI meters. Based on sample design methodology, this could increase accuracy by up to 10% for our load shapes and statistics.

Duke Energy Indiana is also integrating third party demographic and housing data with Duke Energy's data to better understand different segments of customers at a very granular level. We will be able use this information to be data driven with our design of rates and EE programs going forward.

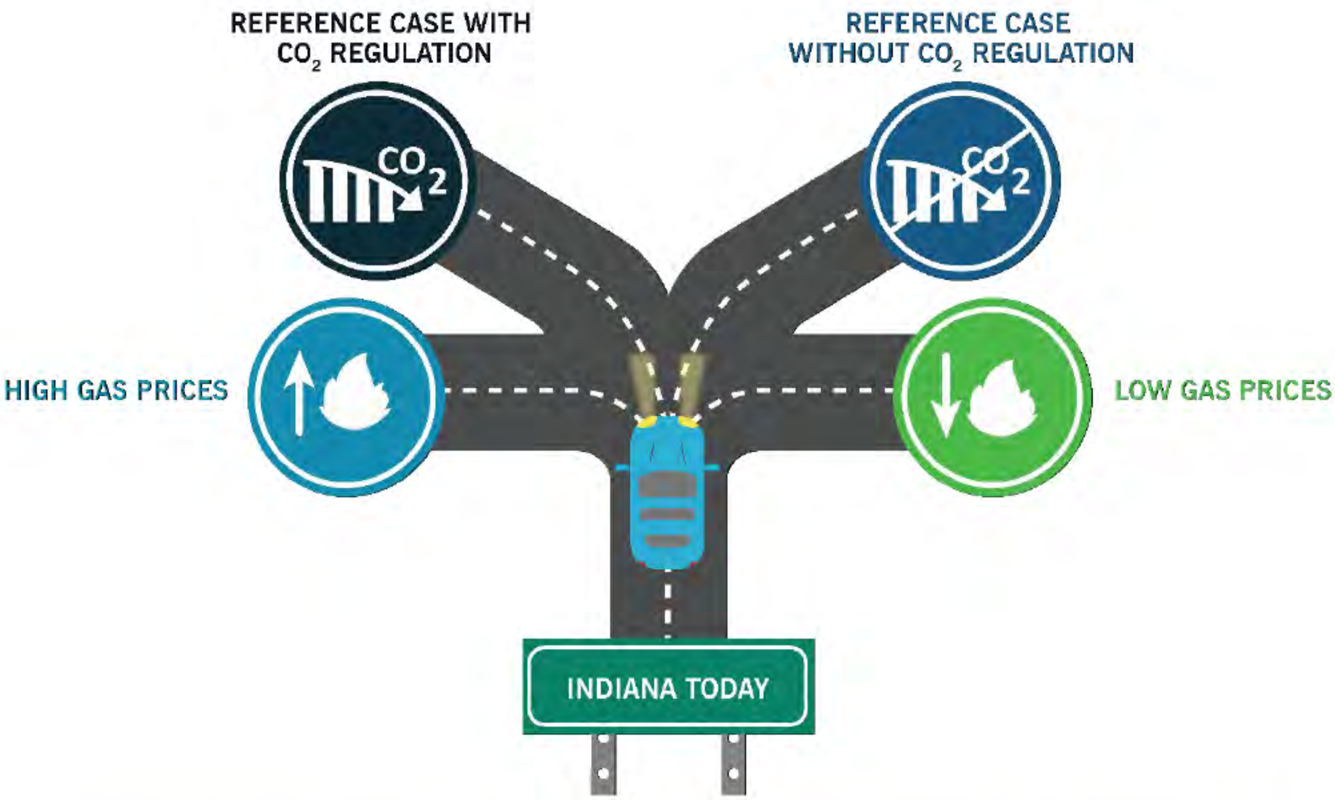

SECTION IV

# DUKE ENERGY INDIANA IN THE FUTURE

Resource planning for an uncertain future requires consideration of the range of operating conditions the Company may face in both the near and long term. Scenario analysis is a useful tool for long range planning as it provides a basis for studying the impact of changes in key variables over time. To achieve this, the scenarios developed must be plausible, internally consistent, sufficiently different from each other, and cover a broad range of potential futures.

The key uncertainties that form the basis of scenarios should be those that are most impactful to resource selection, have been or are anticipated to be highly variable, and are difficult to predict with confidence. Through internal analysis and discussions during stakeholder meetings, the key variables selected as the foundation for scenario development were natural gas prices and carbon regulation. Once the key variables were determined, forecasts were developed for each and grouped into themes that align with a narrative describing a future world consistent with the forecasts of the key variables. To ensure internal consistency of the scenario, additional modeling was conducted to develop MISO power price projections consistent with the other input variables.

Duke Energy Indiana considered four different scenarios:



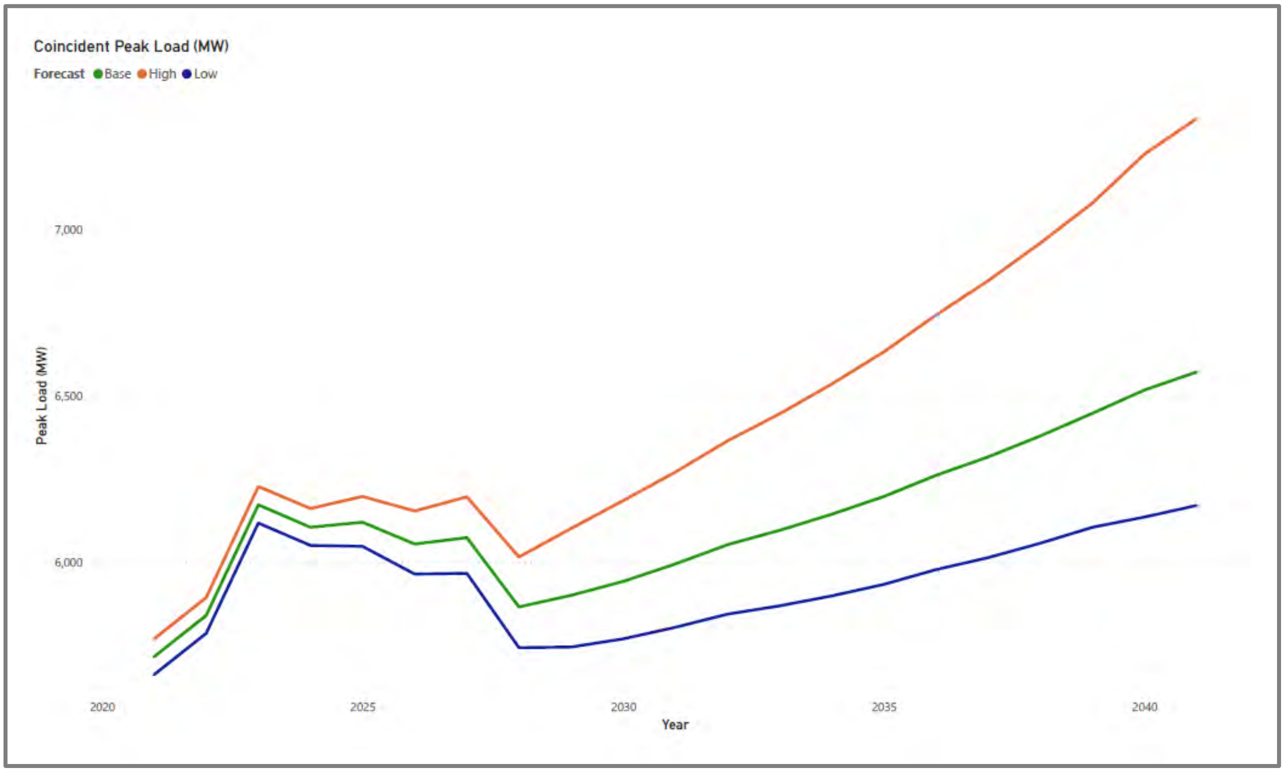

| SCENARIOS | ENVIRONMENTAL REGULATIONS | LOAD | GAS PRICES | COAL PRICES |
|---|---|---|---|---|
| Reference w/o $CO_2$ Reg | No $CO_2$ tax | Base | Base | Base |
| Reference w/ $CO_2$ Reg | $CO_2$ tax starting in 2025 | Base | Base | Base |
| High Gas Prices | No $CO_2$ tax | Base | High | High |
| Low Gas Prices | No $CO_2$ tax | Base | Low | Low |

## ASSUMPTIONS COMMON TO ALL SCENARIOS

In coming up with the scenarios, we focused on the assumptions that have the greatest impact on resource selection – carbon regulation and natural gas prices. The less impactful assumptions were kept the same for each scenario and in the instance of the cost of renewables, new gas generation, winter wind capacity value and the social cost of carbon are analyzed in the sensitivity part of Section V.

The figure below shows the load forecast for base, high and low load which applies to all scenarios.

## FIGURE IV.1
## PEAK LOAD FORECAST – REFERENCE CASE



## REFERENCE WITHOUT CARBON REGULATION SCENARIO

The Reference Case without Carbon Regulation envisions many aspects and trends of the present persisting into the future. There is no state nor national carbon regulation in place. Load growth is moderate with an average annual growth rate of approximately 0.5% over the 20-year planning period. Technological innovation continues to drive down the cost of renewable resources and energy efficiency measures, increasing the economic competitiveness of these resources. Increases in the cost of oil, gas and coal are moderate, based on modest inflation expectations and incremental improvements in extraction technology and methods. Below are the key assumptions used in the Reference Case without Carbon Regulation, and the resulting power prices developed through modeling of the MISO region.

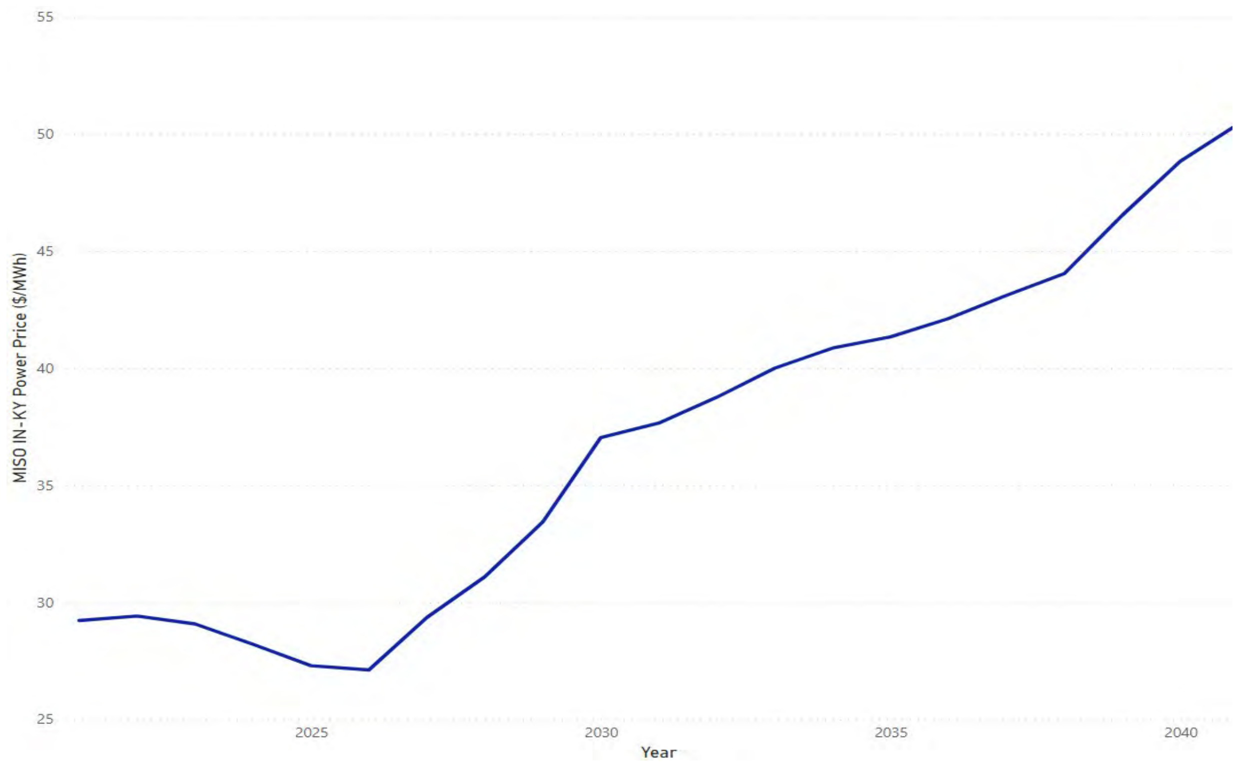
### FIGURE IV.2
### ANNUAL AVERAGE GAS PRICE – REFERENCE W/O $CO_2$ REGULATION
### [CONFIDENTIAL]

[redacted]

FIGURE IV.3
ANNUAL AVERAGE COAL PRICE – REFERENCE W/O $CO_2$ REGULATION
[CONFIDENTIAL]

[redacted]

## FIGURE IV.4
## ANNUAL AVERAGE POWER PRICE – REFERENCE W/O $CO_2$ REGULATION



## REFERENCE WITH CARBON REGULATION

The Reference Case with Carbon Regulation holds many of the same aspects and trends of the Reference Case without Carbon Regulation. The exception is a response to climate change resulting in the imposition of a price on carbon emissions of $5/ton beginning in 2025, increasing by $5/ton per year thereafter. The lower capital costs for renewable projects and presence of a carbon price obviates any push to extend federal tax incentives for renewables resulting in their phase out in accordance with current policy. Below are the key assumptions used in the Reference Case with Carbon Regulation, and the resulting power prices developed through modeling of the MISO region.

### FIGURE IV.5
### CARBON PRICE – REFERENCE W/ $CO_2$ REGULATION

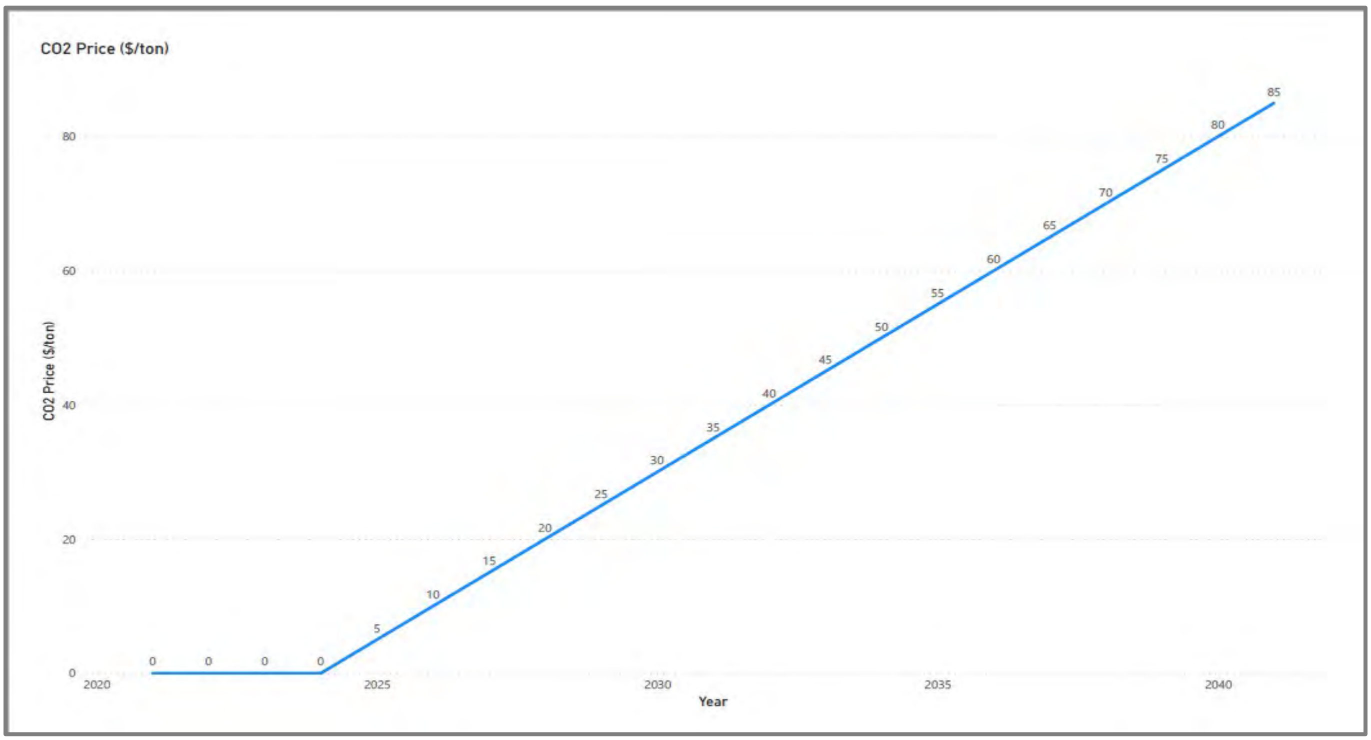


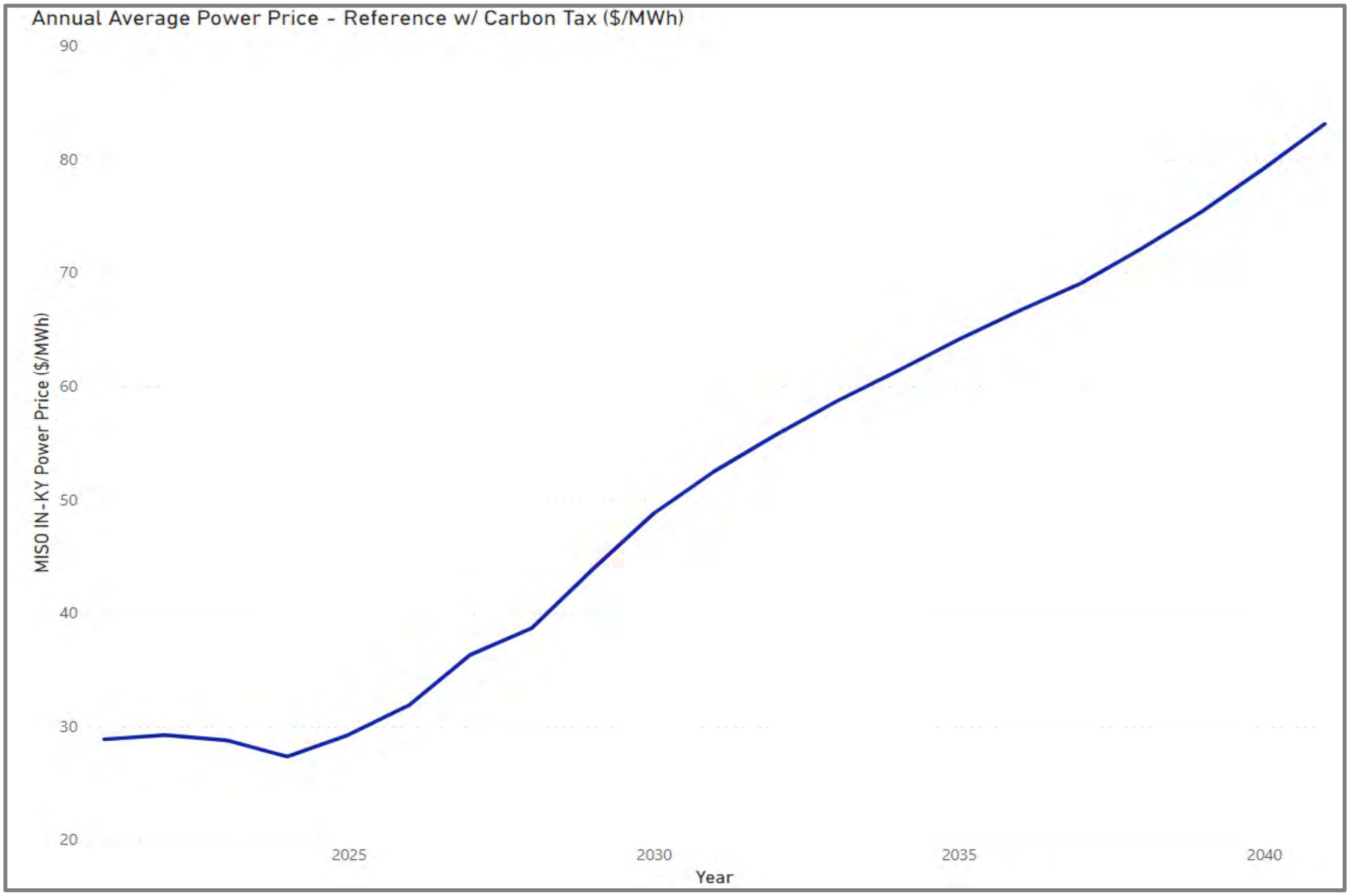
FIGURE IV.6
ANNUAL AVERAGE GAS PRICE – REFERENCE W/ $CO_2$ REGULATION
[CONFIDENTIAL]

[redacted]

FIGURE IV.7
ANNUAL AVERAGE COAL PRICE – REFERENCE W/ $CO_2$ REGULATION
[CONFIDENTIAL]

[redacted]

## FIGURE IV.8
## ANNUAL AVERAGE POWER PRICE – REFERENCE W/ $CO_2$ REGULATION



## HIGH GAS PRICES SCENARIO

The High Gas Prices scenario also utilizes the same values as the Reference Case without Carbon Regulation for load and carbon assumptions. However, in this scenario, the AEO's Low Oil & Gas Supply Scenario data was used to scale up the gas prices for the High Gas Prices Scenario.

The charts below show the expected high gas price average by year and the resulting power prices developed through modeling of the MISO region for this scenario.

## FIGURE IV.9
## ANNUAL AVERAGE GAS PRICE – HIGH GAS PRICES SCENARIO
## [CONFIDENTIAL]

[redacted]

FIGURE IV.10
ANNUAL AVERAGE COAL PRICE – HIGH GAS PRICES SCENARIO
[CONFIDENTIAL]

[redacted]

# FIGURE IV.11
# ANNUAL AVERAGE POWER PRICE – HIGH GAS PRICES SCENARIO


## LOW GAS PRICES SCENARIO

The Low Gas Prices case utilizes the same values as the Reference Case without Carbon Regulation for load and carbon. However, in this scenario, the AEO's High Oil & Gas Supply Scenario data was used to scale down the gas prices for the Low Gas Prices Scenario.

The charts below show the expected low gas price average by year and the resulting power prices developed through modeling of the MISO region, for this scenario.

FIGURE IV.12
ANNUAL AVERAGE GAS PRICE – LOW GAS PRICES SCENARIO
[CONFIDENTIAL]

[redacted]

FIGURE IV.13
ANNUAL AVERAGE COAL PRICES – LOW GAS PRICES SCENARIO
[CONFIDENTIAL]

[redacted]

## FIGURE IV.14
## ANNUAL AVERAGE POWER PRICE – LOW GAS PRICES SCENARIO

SECTION V

# CANDIDATE RESOURCE PORTFOLIOS

This section includes descriptions and analysis of the resource portfolios we evaluated for the 2021 IRP. These include the optimized portfolios, each of which is designed to minimize costs under a particular scenario; the hybrid portfolios, which are designed to improve upon the optimized portfolios and balance our objectives in ways that the EnCompass model cannot; and finally stakeholder inspired portfolios, each of which was based on collaboration with a stakeholder or stakeholder group. The first part of this section is a detailed list of the resource types available for selection in the IRP.

## A. OBJECTIVES OF THE 2021 IRP

The major objectives of the IRP presented in this filing, developed with input from Duke Energy Indiana stakeholders, are:


- **Provide reliable energy.** Reliability is measured using reserve margin, dispatchable resources as a percentage of load, the ability for a portfolio to serve load in all years of the IRP planning period, and the average percentage of annual market purchases.
- **Maintain a resilient and stable grid.** Resilience/Stability uses diversity of resources as measured by the Herfindahl – Hirschman Index (HHI), challenges in executing the portfolio and the ability for the portfolio mix to serve load in extreme weather as metrics. Challenges in executing the portfolio include, but are not limited to supply chain limitations, the number of large construction projects included through 2030 and the rate of the new resource additions. A measured transition is required to maintain a resilient and stable grid.

- **Provide economic service.** Affordability metrics for this IRP are the average of the portfolio Present Value Revenue Requirement (PVRR) across scenarios and the five-year Compound Annual Growth Rate (CAGR) of electric utility rates in the reference case without $CO_2$ regulation.
- **Minimize environmental impact, including carbon emissions.** Environmental Sustainability is measured by 2040 $CO_2$ reduction in percentage and average annual tons emitted, meeting Duke Energy climate goals, water usage, as well as Sulfur Dioxide ($SO_2$), Nitrogen Oxides ($NO_x$) and Particulate Matter (PM) emissions.
- **Maintain portfolio flexibility.** Portfolio flexibility is measured using a range of PVRRs across scenarios. The lower the range, the more flexible a portfolio is under a variety of potential futures (*i.e.*, scenarios).

## B. CANDIDATE RESOURCES FOR THE 2021 IRP

## SUPPLY-SIDE RESOURCES

Based on the technical and commercial availability screening described in Section II.C, the following technologies were excluded from consideration in this IRP: advanced nuclear reactors, solar steam augmentation, fuel cells, supercritical $CO_2$ Brayton cycle, liquid air energy storage, nonlithium-ion battery storage, geothermal, offshore wind, landfill gas, pumped storage hydropower, and compressed air energy storage.

The Company considered for inclusion in this IRP a diverse range of technologies utilizing a variety of different fuels, including Combustion Turbines (CT), Combined Cycle (CC), reciprocating engines, Small Modular Nuclear Reactors (SMR) and $H_2$ CTs. SMRs and $H_2$ CTs are emerging technologies; therefore, they are do not become viable until later in the planning horizon. Natural gas CC with carbon capture utilization and storage (CCUS) was not included as a resource in the analysis, but could be a substitute for SMR when selected. SMRs and CC with CCUS have comparable levelized costs of energy when using base fuel cost and technology cost assumptions. The viability of natural gas CC with CCUS is site dependent and will be evaluated in more detail when siting new combined cycle generation. In addition, onshore wind, solar photovoltaic, and lithium-ion battery storage options were included in the analysis. Table V.1 below provides an overview of the characteristics of the supply-side resources available for selection in this IRP.

## FIGURE V.1
## UNIT CHARACTERISTICS FOR POTENTIAL SUPPLY-SIDE RESOURCE ADDITIONS [CONFIDENTIAL]

| Costs | Units | CT[5] | 2x1 F CC[6] | 2x1 J CC[6] | Recip[7] | CHP[8] | Nuclear | SMR | Wind | Solar[9] | Battery Storage[10] | Solar + Storage[11] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Capital Cost ($2021)[1] | $/kW | [redacted] | | | | | | | | | | |
| First Year Unit is Available | | 2026 | 2027 | 2027 | 2026 | 2026 | 2031 | 2035 | 2023 | 2022 | 2022 | 2022 |
| Fixed Charge Rate (real, levelized) | | [redacted] | | | | | | | | | | |
| ST Capital Cost Inflation Rate (nominal) | | | | | | | | | | -1.8% | -2.7% | -2.1% |
| LT Capital Cost Inflation Rate (nominal) | | 1.0% | 1.2% | 1.2% | 1.4% | 1.0% | 1.0% | 1.0% | 1.4% | 0.6% | 1.2% | 0.6% |
| Variable O&M Cost ($2021)[2] | $/MWh | [redacted] | | | | | | | | | | |
| Fixed O&M Cost ($2021)[3] | $/kW-yr | [redacted] | | | | | | | | | | |
| Operating Characteristics | | | | | | | | | | | | |
| Maximum Load | | | | | | | | | | | | |
| Winter | MW | 928 | 816 | 1221 | 201 | 21 | 2324 | 878 | 150 | 75 | 50 | 75 + 20 |
| Summer | MW | 840 | 775 | 1121 | 201 | 17 | 2324 | 878 | 150 | 75 | 50 | 75 + 20 |
| Contribution to Peak | % Summer MWs | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 13% [14] | 58% [15] | 80% | 55% [16] |
| Minimum Load[4] | | | | | | | | | | | | |
| Winter | MW | 412 | 170 | 182 | 7 | 12 | 670 | 176 | N/A | N/A | N/A | N/A |
| Summer | MW | 361 | 152 | 167 | 7 | 8 | 670 | 176 | N/A | N/A | N/A | N/A |

# FIGURE V.2 (CONT.)
## UNIT CHARACTERISTICS FOR POTENTIAL SUPPLY-SIDE RESOURCE ADDITIONS [CONFIDENTIAL]

| Costs | Units | CT[5] | 2x1 F CC[6] | 2x1 J CC[6] | Recip[7] | CHP[8] | Nuclear | SMR | Wind | Solar[9] | Battery Storage[10] | Solar + Storage[11] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Heat Rate | | | | | | | | | | | | |
| Winter | Btu/kWh | 10125 | 6935 | 6622 | 8410 | 10129 | 10510 | 11370 | N/A | N/A | N/A | N/A |
| Summer | Btu/kWh | 10547 | 6895 | 6623 | 8500 | 11036 | 10510 | 11370 | N/A | N/A | N/A | N/A |
| Outage Rates | | | | | | | | | | | | |
| Planned | | [redacted] | | | | | | | | | | |
| Unplanned | | [redacted] | | | | | | | | | | |
| Emissions Rates[2] | | | | | | | | | | | | |
| NOx | lb/MWh | 0.41 | 0.05 | 0.05 | 0.20 | 0.05 | N/A | N/A | N/A | N/A | N/A | N/A |
| $SO_2$ | lb/MWh | 0.02 | 0.01 | 0.01 | 0.02 | 0.02 | N/A | N/A | N/A | N/A | N/A | N/A |
| $CO_2$ | lb/MWh | 1229 | 827 | 795 | 1020 | 1298 | N/A | N/A | N/A | N/A | N/A | N/A |

NOTE: the general rate of inflation is assumed to be 2.5% per year

[1] Based on summer maximum load; includes interconnection cost and allowance for funds used during construction

[2] Based on summer heat rate

[3] Includes cost of firm gas transmission for CC and CHP

[4] Applicable for dispatch technologies only

[5] Block of 4 combustion turbines

[6] Parameters include full duct firing

[7] Block of 12 reciprocating engines

[8] CHP model assumptions include steam sales at $10.30 per thousand pounds

[9] Single-Axis Tracking with 1.45 overpanel ratio

[10] 4-hour duration storage including 90% depth of discharge limit

[11] 75 MW solar facility with 1.65 overpanel ratio plus 20 MW, 4-hour duration storage including 90% depth of discharge limit

[12] [redacted]

[13] [redacted]

[14] The wind contribution to peak for the Wind ELCC sensitivity study is 20%

[15] The initial solar contribution to peak is 58%, but it drops as more solar is installed. At 1500 MW installed it drops to 35%, and at 3000 MW installed it drops to 28%

[16] Solar plus storage contribution to peak does not drop with additional installed capacity and is not built until solar contribution to peak reduces

In addition to the characteristics listed in the table above, we imposed certain minor constraints on the model governing when certain resources could be added or retired and how much of each resource could be constructed in each year. The following limitations were imposed:

- No unit was permitted to retire before 2023. This reflects the time it would take for the Company to prepare to take a unit offline, as well as make any required transmission upgrades, regulatory filings or environmental permit changes.
- Retirement analysis was conducted only on the coal units and Edwardsport IGCC. Other units were not considered for economic retirement.
- Partial units were modeled in EnCompass for nuclear, CC, CT, SMR, solar and wind resources to better understand how the timing of resource needs is distributed and to reflect our ability to partner with other entities on new generating stations.
- Annual capacity additions for each resource type are limited to reflect practical constraints. The MISO scenario specific resource mixes were used to guide these limitations.
- The time required to permit and construct each unit type is reflected in the first year available shown in Table V.1.
- Solar and wind resources contribute to meeting the planning reserve margin requirement at less than nameplate capacity, reflecting the fact that these resources may not be fully available at the time of peak load. Solar is counted at 50% of nameplate capacity (0% in winter) and wind at 13%, which is consistent with MISO's treatment of these resource types. A wind effective load carrying capability (ELCC) sensitivity was run that increased the firm capacity of wind resources to

20% in the winter. Battery storage is valued at 80% of installed capacity to reflect the possibility that the battery may not be fully charged at the peak hour.

## DEMAND-SIDE RESOURCES

For the purposes of the 2021 IRP, the Company developed 10 sub-portfolios of energy efficiency (EE) programs (also referred to as "bundles"). These bundles were designed to be treated similarly to supply-side resource options for selection by the IRP models. The energy efficiency bundles were modeled based on the currently approved EE portfolio and two of the four 2021 Duke Energy Indiana Market Potential Study (MPS) scenarios: the Expanded Measure List and the Expanded Measure List with Avoided Cost Sensitivity. These two scenarios were selected as the basis for the bundles in collaboration with the EE Oversight Board due to having the lowest levelized cost per MWh for EE savings.

The EE programs in these scenarios were divided into five distinct time periods: 2021-2023 (the current DSM portfolio), 2024-2026 (next DSM portfolio filing), 2027-2034, 2035-2042, and 2043-2050. These bundles were available for selection in the EnCompass model alongside the supply-side resource options. In each of the five time periods, the EnCompass model was allowed to select the bundle based on either of the MPS scenarios or no EE for that time period. It should be noted that the IRP is a 20-year view and the inclusion of EE bundles after 2040 are meant to lessen the impact of any end effects that might come up in the modeling.

The EE programs described above contain demand response (DR) programs available to residential and some non-residential customers. In addition, the bundles contain DR programs available to larger non-residential customers. All DR programs described are primarily utilized as an emergency resource to maintain system reliability. The demand capability (MW) of these programs was made available to all resource portfolios described below.

Additional details on demand-side resources, bundles and the screening process for demand-side resources are available in Appendix D.

## RESOURCE DECISIONS COMMON TO ALL PORTFOLIOS

Certain resource decisions to which the Company had committed prior to the completion of this IRP analysis are included in all portfolios. These are:

- Retirement of Gallagher 2 and 4 in 2021
- Retirement of Noblesville CC in 2034
- EE programs through 2023 as approved under Cause No. 43955 DSM-8
- 17 MW CHP project with planned completion in 2021
- 47MW of existing solar including PPAs and Duke Energy Indiana-owned solar
- 10 MW of battery storage added in 2019 and 5 MW added in 2020
- 100 MW wind PPA expires in 2028
- 21 MW of solar PPAs expire in 2036
- Contracted sale of 50 MW of CT capacity ends in 2022

## C. OPTIMIZED RESOURCE PORTFOLIOS

Recall that an optimized portfolio is designed to be least cost under the assumptions of a specific scenario. Those scenario assumptions are the inputs to the EnCompass model, which selects resource additions and retirements to minimize the PVRR for the portfolio while meeting the planning reserve margin requirement. There are four optimized portfolios, which align with the scenarios.

## REFERENCE CASE WITHOUT CARBON REGULATION

As a baseline, Duke Energy Indiana created a portfolio optimized for a scenario that utilizes our base forecasts for load, generation costs, fuel prices and does not include a carbon tax.

This portfolio retains most of the existing coal assets and adds a combined cycle and solar generation.

| OPT REF w/o CO2 Reg | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | | | | | | | | | | | | | | | | | | |
| **Edwardsport CC** | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | | | | | | |
| **CC 1** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **CC 2 & 3** | | | | | | | | | | | | | | | | | | | | |
| **Capacity PPAs** | 50 | 250 | 400 | | | | | | | | | | | | | | | | | |
| **CT** | | | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| **DR** | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 |
| **Solar** | 47 | 47 | 47 | 247 | 247 | 247 | 247 | 247 | 247 | 247 | 247 | 247 | 247 | 247 | 447 | 597 | 675 | 875 | 925 | 1,125 |
| **Solar & Storage** | | | | | | | | | | | | | | | | | | | | |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | | | | | | | | | | | 50 | 50 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

## REFERENCE CASE WITH CARBON REGULATION

The most impactful assumption on the resource decision is Carbon Regulation. This scenario also uses our base forecasts for load, generation costs, fuel prices but adds a carbon tax that begins at \$5/ton in 2025 and grows by \$5/ton per year thereafter.

Given the impact of the carbon tax on coal generation, this portfolio retires existing coal units by 2031, adds two combined cycles, and significant amounts of solar and wind.

| Opt Ref w/ CO2 Reg | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cayuga 1&2 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| Edwardsport IGCC | 618 | 618 | | | | | | | | | | | | | | | | | | |
| Edwardsport CC | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| Gibson 1&2 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | 635 | 635 | 635 | | | | | | | | | | |
| Gibson 3 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | | |
| Gibson 4 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| Gibson 5 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | | | |
| Noble CC | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| ZELFR | | | | | | | | | | | | | | | | | | | | |
| CC 1 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| CC 2 & 3 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| Capacity PPAs | 50 | 250 | 450 | | | | | | | | | | | | | | | | | |
| CT | | | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 464 | 464 | 464 | 464 | 464 |
| EE | 53 | 85 | 119 | 151 | 178 | 207 | 249 | 268 | 292 | 315 | 334 | 345 | 355 | 363 | 379 | 372 | 362 | 354 | 351 | 346 |
| DR | 497 | 507 | 512 | 533 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 |
| Solar | 47 | 47 | 147 | 547 | 547 | 547 | 547 | 547 | 747 | 1,097 | 1,497 | 1,897 | 2,297 | 2,697 | 2,897 | 3,097 | 3,275 | 3,475 | 3,675 | 3,875 |
| Solar & Storage | | | | | | | | | | | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| Wind (incl Benton) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | 100 | 300 | 500 | 700 | 900 | 1,100 | 1,300 | 1,500 | 1,700 | 1,900 | 2,100 | 2,300 |
| Storage | | | | | | | | | | | | | | | | | | | | |

## HIGH GAS PRICES

The High Gas Prices future scenario describes a world with higher gas prices than in the Reference Cases where the gas prices in the AEO's Low Oil and Gas Supply scenario was used to scale up the gas prices in this scenario. No carbon tax is assumed in this scenario.

Higher gas prices increase the power price and keep coal generation operating through the term of the IRP. No combined cycles are added with solar and wind being added mostly in the 2030s.

| HIGH GAS | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cayuga 1&2 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 |
| Edwardsport IGCC | 618 | 618 | | | | | | | | | | | | | | | | | | |
| Edwardsport CC | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| Gibson 1&2 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 |
| Gibson 3 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 |
| Gibson 4 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 |
| Gibson 5 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 |
| Noble CC | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| ZELFR | | | | | | | | | | | | | | | | | | | | |
| CC 1 | | | | | | | | | | | | | | | | | | | | |
| CC 2 & 3 | | | | | | | | | | | | | | | | | | | | |
| Capacity PPAs | 50 | 250 | 400 | | | | | | | | | | | | | | | | | |
| CT | | | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 |
| EE | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| DR | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 |
| Solar | 47 | 47 | 47 | 147 | 147 | 147 | 147 | 147 | 147 | 147 | 297 | 297 | 397 | 597 | 797 | 847 | 975 | 1,075 | 1,325 | 1,525 |
| Solar & Storage | | | | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 75 |
| Wind (incl Benton) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | | | | 200 | 400 | 600 | 800 | 1,000 | 1,200 | 1,400 | 1,600 | 1,800 |
| Storage | | | | | | | | | | | | | | | | | | | | |

## LOW GAS PRICES

The Low Gas Prices future scenario describes a world with lower gas prices than in the Reference Cases where the gas prices in the AEO's High Oil and Gas Supply scenario was used to scale up the gas prices in this scenario. No carbon tax is assumed in this scenario.

Lower gas prices decrease the power price and drive the retirement of all coal generation by 2029. Additionally, lower power prices stifle the addition of solar and wind resources. Three combined cycles are added taking advantage of lower fuel costs.

| LOW GAS | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | | | | | | | | | | | | | | | | | | |
| **Edwardsport CC** | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | | | | | | | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | | | | | | |
| **CC 1** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **CC 2 & 3** | | | | | | | 1,221 | 1,221 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 | 2,442 |
| **Capacity PPAs** | 50 | 250 | 400 | | | | | | | | | | | | | | | | | |
| **CT** | | | 232 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 696 | 696 | 696 | 928 | 928 |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| **DR** | 497 | 507 | 512 | 533 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 |
| **Solar** | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 47 | 197 | 197 | 197 | 175 | 175 | 175 | 175 |
| **Solar & Storage** | | | | | | | | | | | | | | | | | | | | |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | | | | | | | | | | 50 | 50 | 50 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

## KEY INSIGHTS FROM OPTIMIZED PORTFOLIOS

The resource additions and retirements that the EnCompass model selected when optimizing the portfolio for the conditions under each of the four different scenarios are very helpful in understanding which assumptions drive significant resource changes and what those changes are. Similarly, the EnCompass model runs in which the optimized portfolios are dispatched in each of the four scenarios, help us understand how a given resource mix would respond to a variety of future conditions. Some of the most important insights from this exercise are:

- Carbon regulation or low gas prices are the primary drivers of coal retirements and the likelihood of either is an important factor to consider in future resource plans.
- Similarly, a price on carbon emissions or low gas prices result in a shift towards CCs, CTs, and solar.
- Gas and solar are consistently selected over wind.
- A coal heavy portfolio would become reliant on the MISO market for a significant part of its energy needs and could represent an increased level of risk for customers in a scenario with carbon regulation. Conversely, a more diverse portfolio would be more self-reliant across a broader range of conditions.

## D. HYBRID PORTFOLIOS

Developing optimized portfolios help us understand how the resource mix should be adjusted to adapt to changes in key variables like load, fuel prices, and carbon regulation. Running those portfolios through the EnCompass model demonstrates how given resource mixes would operate under different future conditions. This provides a starting point for developing alternative of hybrid portfolios designed to retain the strengths of the optimized portfolios, while minimizing risks. We identified the following as areas of focus for alternative portfolios:

- There are dramatic differences between portfolios optimized for a future with and without carbon regulation. Given the unpredictability of this issue, we need a plan that prepares us for a low carbon future without incurring major costs prematurely.
- Several of the optimized portfolios would rely heavily on market energy under certain scenarios. The EnCompass model selects resources as if our market price forecasts are 100% known. We need a plan that limits market exposure while still allowing us to capture some of the potential benefits of low market prices.
- The retirement of baseload resources and addition of intermittent resources will change the shape of the net load that dispatchable generation needs to serve. We need a plan that accounts for the fact and can maintain reliability.
- Unit retirements selected by the EnCompass model are based entirely on cost and capacity need. The model does not account for other constraints such as joint ownership, site costs shared with other units, transmission constraints, etc. We need a plan that is operable in the real world.
- Perhaps most importantly, the EnCompass model optimizes around cost. We need a plan that balances the goal of keeping costs low with other objectives such as risk, carbon reduction, and generation diversity.

The alternative portfolios described below were developed to address these concerns.

## BALANCED HYBRID

The Balanced Hybrid portfolio is designed to gradually diversify the resource mix without steeply increasing cost to customers over a short period. This portfolio accelerates coal retirements relative to the previous IRP, replacing that coal capacity with a mix of CC, CT, solar, wind, and EE. Solar plus storage is added beginning in the early 2030s. Renewable capacity is added gradually to limit cost impacts in any one year. Coal retirements are grouped in a way that would be feasible given constraints

| Balanced Hybrid | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cayuga 1&2 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| Edwardsport IGCC | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 |
| Edwardsport CC | | | | | | | | | | | | | | | | | | | | |
| Gibson 1&2 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 |
| Gibson 3 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 |
| Gibson 4 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| Gibson 5 | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| Noble CC | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| ZELFR | | | | | | | | | | | | | | | | | | | | |
| CC 1 | | | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 |
| CC 2 & 3 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| Capacity PPAs | 50 | 250 | | | | | | | | | | | | | | | | | | |
| CT | | | | | | | | | | | | | | | | | | | | |
| EE | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| DR | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 |
| Solar | 47 | 47 | 247 | 497 | 497 | 497 | 497 | 497 | 497 | 697 | 797 | 947 | 1,047 | 1,297 | 1,297 | 1,397 | 1,425 | 1,525 | 1,675 | 1,775 |
| Solar & Storage | | | | | | | | | | | 75 | 150 | 225 | 300 | 375 | 450 | 525 | 600 | 675 | 750 |
| Wind (incl Benton) | 100 | 100 | 100 | 150 | 150 | 150 | 150 | 50 | 50 | 150 | 250 | 350 | 450 | 550 | 600 | 800 | 900 | 1,000 | 1,100 | 1,200 |
| Storage | | | | | | | | | | | | | | | | | | | | |

that are not captured in the EnCompass model. Edwardsport is run on coal throughout the period to provide reliable, baseload power with on-site fuel.

## RENEWABLES/CC HYBRID

Similar to the Balanced Portfolio, the Renewables/CC Hybrid portfolio transitions the fleet in a measured way but relies more heavily on combined cycle technology.  Under this portfolio, two combined cycles are added, as well as meaningful amounts of solar and wind generation.

| Renewable-CC Portfolio | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | | | | | | |
| **Edwardsport CC** | | | | | | | | | | | | | | | 541 | 541 | 541 | 541 | 541 | 541 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | 878 | 878 | 878 | 878 | 878 | 878 |
| **CC 1** | | | | | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 |
| **CC 2 & 3** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **Capacity PPAs** | 50 | 250 | 500 | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | | | | | | | | | | | | | | |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 249 | 268 | 292 | 315 | 334 | 345 | 355 | 363 | 380 | 374 | 365 | 358 | 355 | 351 |
| **DR** | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 |
| **Solar** | 47 | 147 | 347 | 547 | 747 | 947 | 1,147 | 1,347 | 1,547 | 1,747 | 1,947 | 2,147 | 2,347 | 2,547 | 2,747 | 2,947 | 3,125 | 3,325 | 3,525 | 3,725 |
| **Solar & Storage** | | | | | | | | | | | | | | | | | | | | |
| **Wind (incl Benton)** | 100 | 100 | 200 | 300 | 400 | 500 | 600 | 600 | 700 | 800 | 900 | 1,000 | 1,100 | 1,200 | 1,300 | 1,400 | 1,500 | 1,600 | 1,700 | 1,800 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

## RENEWABLES/CC/CT HYBRID

The Renewables/CC/CT portfolio was added after evaluation of the hybrid portfolios and includes both combined cycles and combustion turbines. Not surprisingly, a portfolio that takes advantage of both generation types is more robust and increases diversity. This portfolio preserves options by extending the operation of some coal generation through 2035, adds combined cycle in 2027 and combustion turbines in 2035. It should also be noted that modern turbine technology is currently and will likely become increasingly capable of burning hydrogen and would therefore be very valuable in simultaneously achieving carbon reduction and maintaining reliability. Solar, wind and storage are added in significant and balanced proportions. Edwardsport IGCC is run on coal through 2035, and switched to operating solely on natural gas thereafter, reducing emissions but still providing dispatchable reliable power.

| Renewables/CC/CT | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | | | | | | |
| **Edwardsport CC** | | | | | | | | | | | | | | | 586 | 586 | 586 | 586 | 586 | 586 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | | | | | | |
| **CC 1** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **CC 2 & 3** | | | | | | | | | | | | | | | | | | | | |
| **Capacity PPAs** | 50 | 250 | 450 | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | | | | | | | | | 1,160 | 1,160 | 1,160 | 1,160 | 1,160 | 1,160 |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| **DR** | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 |
| **Solar** | 47 | 47 | 197 | 447 | 647 | 847 | 1,047 | 1,247 | 1,497 | 1,547 | 1,697 | 1,847 | 1,997 | 2,147 | 2,297 | 2,447 | 2,575 | 2,725 | 2,875 | 3,025 |
| **Solar & Storage** | | | | | | | 75 | 150 | 225 | 300 | 450 | 525 | 600 | 675 | 900 | 975 | 1,125 | 1,275 | 1,425 | 1,500 |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 200 | 400 | 600 | 900 | 1,200 | 1,500 | 1,800 | 2,100 | 2,400 | 2,600 | 2,800 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

## RENEWABLES/CT HYBRID

The Renewables/CT Hybrid portfolio transitions the fleet in a measured way but relies more heavily on combustion turbines. Under this portfolio, one unit of a combined cycle is added with almost 1400 MW of CTs being added in 2027. Solar and wind generation is added as well as sizable amounts of storage paired with solar.

| Renewable-CT Portfolio | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | 618 | | | | | | |
| **Edwardsport CC** | | | | | | | | | | | | | | | 586 | 586 | 586 | 586 | 586 | 586 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | 878 | 878 | 878 | 878 | 878 | 878 |
| **CC 1** | | | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 |
| **CC 2 & 3** | | | | | | | | | | | | | | | | | | | | |
| **Capacity PPAs** | 50 | 200 | | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 | 1,392 |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 249 | 268 | 292 | 315 | 334 | 345 | 355 | 363 | 380 | 374 | 365 | 358 | 355 | 351 |
| **DR** | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 |
| **Solar** | 47 | 147 | 347 | 547 | 747 | 947 | 1,147 | 1,347 | 1,547 | 1,747 | 1,947 | 2,147 | 2,347 | 2,547 | 2,747 | 2,947 | 3,125 | 3,325 | 3,525 | 3,725 |
| **Solar & Storage** | | | | | | | | | | | 75 | 150 | 225 | 300 | 375 | 450 | 525 | 600 | 675 | 750 |
| **Wind (incl Benton)** | 100 | 100 | 200 | 300 | 400 | 500 | 600 | 600 | 700 | 800 | 900 | 1,000 | 1,100 | 1,200 | 1,300 | 1,400 | 1,500 | 1,600 | 1,700 | 1,800 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

## E. STAKEHOLDER INSPIRED PORTFOLIOS

### BIDEN 100

Based on stakeholder feedback, a portfolio that achieves 100% $CO_2$ reduction from the 2005 baseline by 2035 was included for consideration. This portfolio transitions from primarily being coal and gas to one that consists of ZELFRs[1], gas turbines capable of burning hydrogen and renewable technologies.

| Biden 100 Portfolio | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 505 | 505 | 505 | 505 | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | | | | | | | | | | | | | | | | | | |
| **Edwardsport CC** | | | | | | | | | | | | | | | | | | | | |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | 635 | | | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | 1,317 | 1,756 | 2,634 | 2,634 | 2,634 | 2,634 | 2,634 | 2,634 |
| **CC 1** | | | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | | | | | | |
| **CC 2 & 3** | | | | | | | | | | | | | | | | | | | | |
| **Capacity PPAs** | 50 | 250 | | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | | | | | 464 | 928 | 928 | 928 | 1,392 | 1,624 | 1,624 | 1,624 | 1,624 | 1,624 |
| **EE** | 53 | 85 | 119 | 154 | 184 | 216 | 260 | 280 | 303 | 324 | 343 | 353 | 364 | 371 | 387 | 379 | 369 | 361 | 358 | 354 |
| **DR** | 497 | 507 | 512 | 931 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 |
| **Solar** | 47 | 347 | 347 | 347 | 1,247 | 1,247 | 1,247 | 1,597 | 2,347 | 3,047 | 3,047 | 3,047 | 3,047 | 3,047 | 3,047 | 3,047 | 3,025 | 3,025 | 3,025 | 3,025 |
| **Solar & Storage** | | | | | | | | | | | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 225 | 225 |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 100 | 500 | 1,100 | 1,600 | 2,000 | 2,500 | 2,700 | 2,700 | 2,700 | 2,700 | 2,700 | 2,700 | 2,700 | 2,700 | 2,700 | 2,700 |
| **Storage** | | | | | | | | | | 250 | 750 | 1,050 | 1,050 | 1,150 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,550 |

[1] Zero emitting load following resource - a placeholder for technology advancements such as small modular nuclear reactors (SMRs).

## BIDEN 90

In recognition of the challenges of getting to 100% reduction by 2035, it was also suggested that a portfolio be developed that achieved 90% reduction would be more feasible. This portfolio shares several similarities as the Biden 100 portfolio with the primary difference being the continued operation of the combined cycle.

| Biden 90 Portfolio | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 505 | 505 | 505 | 505 | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | | | | | | | | | | | | | | | | | | |
| **Edwardsport CC** | | | | | | | | | | | | | | | | | | | | |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | 635 | 635 | 635 | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | 878 | 1,317 | 1,756 | 1,756 | 1,756 | 1,756 | 1,756 | 1,756 |
| **CC 1** | | | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 | 815 |
| **CC 2 & 3** | | | | | | | | | | | | | | | | | | | | |
| **Capacity PPAs** | 50 | 250 | | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | | | | | 464 | 696 | 696 | 696 | 928 | 1,160 | 1,160 | 1,160 | 1,160 | 1,160 |
| **EE** | 53 | 85 | 119 | 154 | 184 | 216 | 260 | 280 | 303 | 324 | 343 | 353 | 364 | 371 | 387 | 379 | 369 | 361 | 358 | 354 |
| **DR** | 497 | 507 | 512 | 931 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 |
| **Solar** | 47 | 247 | 247 | 247 | 1,097 | 1,097 | 1,097 | 1,547 | 2,147 | 2,997 | 3,047 | 3,047 | 3,047 | 3,047 | 3,047 | 3,047 | 3,025 | 3,025 | 3,025 | 3,025 |
| **Solar & Storage** | | | | | | | | | | | | 75 | 75 | 75 | 300 | 375 | 375 | 600 | 600 | 600 |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 150 | 400 | 950 | 1,400 | 1,800 | 2,150 | 2,700 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,800 | 2,850 | 2,850 |
| **Storage** | | | | | | | | | | 200 | 700 | 850 | 850 | 1,050 | 1,400 | 1,400 | 1,400 | 1,400 | 1,400 | 1,450 |

## ENVIRONMENTALLY FOCUSED

This portfolio was developed with the principles of retiring all of the coal generation by 2030 and not building new gas resources.

The resulting portfolio achieves those principles and transitions to one that is mostly solar, wind and storage.

| Enviro Focused Portfolio | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | | | | | | | | | | | | | | | | | | |
| **Edwardsport CC** | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | | | | | | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | | | | | | |
| **CC 1** | | | | | | | | | | | | | | | | | | | | |
| **CC 2 & 3** | | | | | | | | | | | | | | | | | | | | |
| **Capacity PPAs** | 50 | 250 | 500 | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | | | | | | | | | | | | | | |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 249 | 269 | 293 | 315 | 335 | 346 | 356 | 364 | 381 | 375 | 366 | 359 | 356 | 353 |
| **DR** | 497 | 507 | 512 | 715 | 721 | 721 | 721 | 721 | 721 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 | 937 |
| **Solar** | 47 | 47 | 247 | 447 | 447 | 447 | 447 | 747 | 1,147 | 1,547 | 1,797 | 1,997 | 2,197 | 2,397 | 2,597 | 2,797 | 2,975 | 3,175 | 3,375 | 3,575 |
| **Solar & Storage** | | | | 75 | 75 | 75 | 75 | 150 | 150 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 | 525 |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 100 | 100 | 300 | 400 | 600 | 800 | 1,000 | 1,200 | 1,400 | 1,600 | 1,800 | 1,950 | 2,100 | 2,200 | 2,300 | 2,400 |
| **Storage** | | | | | | 100 | 600 | 1,100 | 1,600 | 2,100 | 2,100 | 2,100 | 2,100 | 2,150 | 2,600 | 2,650 | 2,650 | 2,650 | 2,850 | 2,900 |

## RELIABLE ENERGY

The Reliable Energy Portfolio focuses on a balanced transition from coal to renewables. The portfolio makes use of current coal and considers CCUS at Edwardsport. Assumptions for this portfolio include a 15-year life for CC plants, adding CCUS to Edwardsport, and 45Q tax credits associated with CCUS. This portfolio demonstrates that coal has a role in the transition to renewables and should be phased out in a measured, economic way.

| Reliable Energy Portfolio | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | 618 | 618 | 618 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 | 429 |
| **Edwardsport CC** | | | | | | | | | | | | | | | | | | | | |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | 635 | 635 | 635 | 635 | 635 |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | 878 | 878 | 878 | 1,317 | 1,317 | 1,317 |
| **CC 1** | | | | | | | | | | | | | | | | | | | | |
| **CC 2 & 3** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **Capacity PPAs** | 50 | 50 | 50 | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | | | | | | | | | | | | | 232 | 232 |
| **EE** | 53 | 85 | 119 | 154 | 184 | 216 | 260 | 279 | 303 | 324 | 342 | 353 | 363 | 370 | 386 | 378 | 368 | 360 | 357 | 353 |
| **DR** | 497 | 507 | 512 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 | 200 |
| **Solar** | 47 | 397 | 797 | 1,197 | 1,597 | 1,997 | 2,397 | 2,797 | 3,197 | 3,597 | 3,997 | 4,397 | 4,797 | 5,197 | 5,597 | 5,997 | 6,375 | 6,775 | 6,875 | 6,875 |
| **Solar & Storage** | | | | | | | | | | | | | | | | | | | | |
| **Wind (incl Benton)** | 100 | 100 | 100 | 300 | 500 | 700 | 900 | 1,000 | 1,200 | 1,400 | 1,600 | 1,800 | 2,000 | 2,200 | 2,400 | 2,600 | 2,800 | 3,000 | 3,000 | 3,000 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

## F. PERFORMANCE OF CANDIDATE RESOURCE PORTFOLIOS

This section summarizes the performance of the resource portfolios described in this chapter with respect to the key objectives for this IRP. All portfolios must satisfy the planning reserve margin requirement that establishes reliability, so we focus on cost, risk, and carbon emissions in this section.

A scorecard was developed and used in the selection of the preferred portfolio across several metrics. The scorecard lists each of the portfolios on the left side of the table and the various performance metrics are listed along the top of the table

# TABLE V.1
# IRP SELECTION CRITERIA

| PORTFOLIOS | | # | METRIC | Reliability | | | Resilience / Stability | | | Affordability | | Environmental Sustainability | | | Portfolio Flexibility |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Dispatchable Resources as a percentage of load[1] | Can portfolio serve load in all years of IRP planning period?[2] | Average percentage of annual market purchases[3] | Diversity of Resources as measured by HHI[4] | Executability[5] | Can portfolio mix serve load in extreme weather weeks in PST?[6] | Average of portfolio PVRRs across scenarios[7] | 5 year CAGR of rates in Ref Scenario w/o CO2[8] | 2040 CO2 Reduction % and Avg Annual Tons Emitted[9] | On track for meeting Duke Energy Climate Goals?[10] | SO2, NOx, PM & Water Emissions[11] | Range of PVRRs across scenarios[12] |
| | | | | Higher better | <.5% Acceptable | <20-25% preferred | Lower better | | | Lower better | Lower better | Greater reducton better | | | Smaller better |
| PORTFOLIOS | Optimized | 1 | Ref w/o CO2 Reg | 115% | 0.24% | 25% | 25% | ● | ● | $16.1 | 0.8% | -47% | No | ◑ | $3.6 |
| | | 2 | Ref w/ CO2 Reg | 104% | 0.36% | 16% | 25% | ◕ | ◕ | $16.1 | 0.8% | -74% | No | ◕ | $3.9 |
| | | 3 | High Gas Prices | 117% | 0.13% | 31% | 31% | ● | ● | $16.5 | 0.9% | -43% | No | ◔ | $4.2 |
| | | 4 | Low Gas Prices | 118% | 0.28% | 15% | 43% | ● | ● | $15.8 | 0.6% | -48% | No | ◑ | $4.9 |
| | Hybrid | 5 | Balanced Hybrid | 115% | 0.06% | 9% | 19% | ◕ | ◕ | $17.5 | 1.4% | -40% | No | ◔ | $1.8 |
| | | 6 | Renewables/CC Hybrid | 108% | 0.08% | 7% | 15% | ◑ | ● | $18.7 | 2.0% | -78% | Yes | ◑ | $2.0 |
| | | 7 | Renewables/CC/CT Hybrid | 91% | 0.23% | 19% | 17% | ◕ | ◑ | $18.0 | 1.3% | -78% | Yes | ◑ | $2.6 |
| | | 8 | Renewables/CT Hybrid | 110% | 0.05% | 17% | 18% | ◑ | ● | $19.3 | 2.0% | -82% | Yes | ◑ | $2.3 |
| | Stakeholder | 9 | Biden 100 | 102% | 0.06% | 12% | 17% | ◔ | ◕ | $21.0 | 1.7% | -96% | Yes | ◕ | $1.3 |
| | | 10 | Biden 90 | 97% | 0.26% | 13% | 17% | ◔ | ◕ | $20.0 | 1.5% | -90% | Yes | ◕ | $1.7 |
| | | 11 | Enviro Focused | 84% | 3.70% | 41% | 18% | ◑ | ◑ | $19.3 | 1.1% | -79% | Yes | ◕ | $3.8 |
| | | 12 | Reliable Energy | 98% | 0.08% | 12% | 19% | ◑ | ◑ | Note 13 | | -64% | No | ◑ | Note 13 |

| ○ | ◔ | ◑ | ◕ | ● |
|---|---|---|---|---|
| Poor | Fair | Good | Very Good | Excellent |

**Notes**

1 (Coal, Gas & Battery MW in 2030) / (Total MW in 2030)
2 Average of Energy Not Served / Total Energy for all years in all scenarios (<.5% due to outages in model)
3 Average of market purchases in all years in all scenarios
4 HHI is a concentration index calculated by adding square of each resources percentage on a MW basis
5 Greater construction level though 2030 drive this metric
6 Applies 2030 portfolio mix to extreme weather weeks in PST
7 Averages PVRRs across all scenarios
8 Average 5 year rate impact due to generation choices
9 CO2 reduction relative to 2005 and includes CO2 associated with market purchases
10 Are the 2040 CO2 emissions of a portfolio less than a linear interpolation between 2005 and 0 in 2050?
11 Composite of pollutants and water consumption based on 2030 portfolio performance
12 (Max PVRR - Min PVRR) for a portfolio across all scenarios
13 The 5 year rate impact of the Reliable Energy portfolio includes all of the capital for CCS but only 1 year of tax credits: stakeholder asked to exclude with the following context "Reliable Energy (RE) and DEI together developed a portfolio during the stakeholder process (the "RE Portfolio"). DEI developed cost estimates and rate impacts for the RE Portfolio, but upon review RE identified issues regarding the evaluation. Given inadequate time to resolve the issues, the parties agreed to describe the portfolio but omit the associated cost and rate analyses from DEI's IRP materials. DEI notes that it believes that the RE Portfolio was competitive in terms of rate impacts."

Below is a brief discussion of each metric from the table above:

**DISPATCHABLE RESOURCES AS A PERCENTAGE OF LOAD.** Using 2030 as a representative year, this metric takes dispatchable MWs (coal, gas, and storage) of the portfolio and divides it by the peak load. Largely due to the existing fleet of combustion turbines and combined cycles, all portfolios have significant quantities of dispatchable generation. While not a concern in 2030, this metric will be one to monitor as the fleet continues to evolve.

**CAN PORTFOLIO SERVE LOAD IN ALL YEARS OF IRP PLANNING PERIOD?** This metric looks at the amount of unserved energy for each portfolio in all years of every scenario. All portfolios exhibit small amounts of unserved energy due to the timing of outages in the model. If this level is below 0.5%, there is not a concern on a portfolio's energy sufficiency. The Environmental Focused portfolio does show higher levels of unserved energy and highlights a vulnerability of energy sufficiency that would need to be made up by higher market purchases.

**AVERAGE PERCENTAGE OF ANNUAL MARKET PURCHASES.** This metric looks at the amount of market purchases as a percentage of total energy need for each portfolio in all years of every scenario. Most portfolios average levels of market purchases that are within historical norms. Two portfolios, High Gas and Environmental Focused, do show higher levels of average market purchases which represents a higher level of risk compared to other portfolios.

**DIVERSITY OF RESOURCES AS MEASURED BY HHI.** This metric looks at the diversity of each portfolio in 2030 as measured by Herfindahl-Hirschman Index (HHI). The HHI sums the squares of the capacity percentage of each resource type and provides a measure of how concentrated or diverse a portfolio is, with a lower HHI showing a portfolio with greater diversity. Most portfolios significantly improve the generating fleet's diversity from the current HHI of 36%. The optimal portfolios tend to be the laggards on this metric and is not a surprising outcome of an optimization that pursues least cost.

**CHALLENGES IN EXECUTING PORTFOLIO.** This metric considered the amount of construction activities that are taking place in the 2020s and includes work related to units going into service in this decade. Additionally, this includes resources with in-service dates in the 2030s whose construction activities must begin in the 2020s. More construction activity increases the challenges of executing a portfolio.

**CAN PORTFOLIO MIX SERVE LOAD IN EXTREME WEATHER WEEKS IN PST?** For this criteria, we made use of the Portfolio Screening Tool (PST) that was developed for stakeholders to vary the composition of the Duke Energy Indiana fleet and see how that portfolio would serve load in extreme weeks for winter, spring and summer. This tool uses actual historic loads, as well as corresponding historical solar and wind output data.

Most portfolios served load in almost all hours, but the few hours and MWs associated with load not being served speaks more directly to the need for a higher reserve margin than a deficiency in the portfolio. Given the transition of the Duke Energy Indiana generating fleet and like transition of the MISO fleet, a forecast of how the MISO reserve margin requirement will change over time will be a meaning full improvement for future IRPs.

Due the high level of renewables and relatively lower level of dispatchable generation, the Environmental Focused portfolio was not able to serve load for several hours and was deficient for over 2,000 MW in two seasons.

**AVERAGE OF PORTFOLIO PVRRS ACROSS SCENARIOS.** This metric takes the simple average of a portfolios' PVRRs across the four scenarios. The metric focuses on long-term costs, with the rate impact being a more meaningful financial metric in the near term.

**5-YEAR COMPOUND ANNUAL GROWTH RATE (CAGR) OF ELECTRIC UTILITY RATES IN REFERENCE SCENARIO W/O $CO_2$ REGULATION.** Rates are what customers experience and given that importance, this IRP includes a rate impact calculation attributable to only changes in the generation resource plan. Generally speaking, the more quickly a portfolio transitions, the more rate impact there will be in the early years.

**2040 $CO_2$ REDUCTION PERCENT.** This metric shows the percentage reduction in $CO_2$ tons emitted, including attribution of $CO_2$ to market purchases, relative to the 2005 baseline.

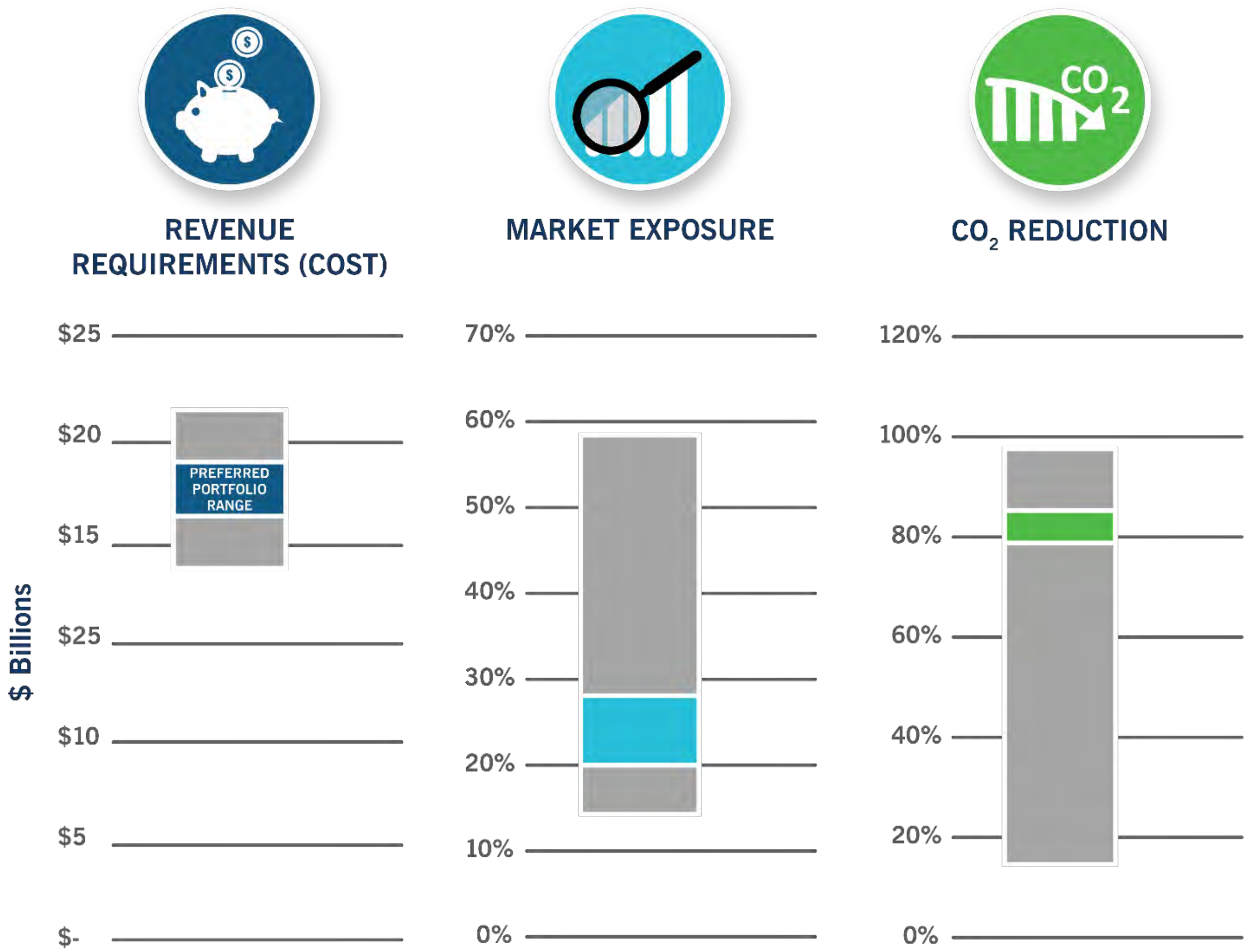
**ON TRACK FOR MEETING DUKE ENERGY CLIMATE GOALS?** This metric compares the average 2040 $CO_2$ emissions of each portfolio with a linear interpolation between the 2005 baseline and the 2050 Duke Energy Climate Goal of being net zero carbon emissions. This metric was added at the request of stakeholders.

**$SO_2$, $NO_X$, PM EMISSIONS AND WATER USAGE.** This metric considers that amounts of $SO_2$, $NO_x$, particulates, and water use for each portfolio. Lower levels of emissions and water usage are preferred.

**RANGE OF PVRRS ACROSS SCENARIOS.** The level of cost as shown by the PVRR is informative, but perhaps even more informative is the range of PVRRs for each portfolio. When a portfolio is modeled in different scenarios, its generation will dispatch differently and result in a different PVRR. The ability for a portfolio to re-dispatch and moderate variabilities in the market is a desirable characteristic and a lower range of PVRRs would reflect this quality.

The chart below shows how the preferred portfolio fares across PVRRs, market purchase level and $CO_2$ reduction compared to the other portfolios across the range of scenarios. While not as complete of a picture as the scorecard, it is indicative of the competitiveness of the preferred portfolio compared to the other portfolios.

## FIGURE V.2
## PREFERRED PORTFOLIO KEY METRICS




## SUMMARY

The results of the analysis presented in the preceding sections highlight the tradeoffs that we faced in selecting the preferred portfolio for this IRP. Based on the robustness with which the Renewables/CC/CT portfolio performed across all four scenarios, it was selected as the preferred portfolio. It performs favorably in terms of the level of market purchases, improves fleet diversity, makes significant reductions in carbon emissions, provides stability in an uncertain world, all with managing reasonable rate impacts.

## G. SENSITIVITY ANALYSIS

As discussed in Section 2, sensitivity analysis is an important tool for assessing how changes to individual assumptions could impact our resource selections. If a change to a particular assumption results in a significant change to the portfolio, then we know that it is very important to either forecast that variable correctly or, more reasonably, to maintain flexibility and be ready to respond to different outcomes for that variable. Reviewing the similarities and differences across the optimized portfolios helps us understand which inputs warrant further examination via sensitivity analysis.

## HIGH LOAD

The top priority for the IRP is to design a resource portfolio that will reliably serve load throughout the planning period. That makes the load forecast a very important input to the process. If our load forecast is too low then reliability may be impacted, but if the forecast is too high then we may build more capacity than necessary, adding unnecessary cost. The former risk is mitigated by the inclusion of the planning reserve margin by which we retain capacity slightly in excess of we expect to need. In addition, some resources, like combustion turbines and solar plants, can be added relatively quickly and in relatively small increments.

This analysis shows that due to the higher load, the optimized portfolio delays the retirement of two Gibson units and adds CT capacity in the latter years. Partially offsetting this additional capacity is a slight reduction in renewable generation.

| Hi LF | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | | | | | | | | | | | | | | | | | | |
| **Edwardsport CC** | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | 635 | 635 | 635 | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | | | | | | |
| **CC 1** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **CC 2 & 3** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **Capacity PPAs** | 50 | 250 | 500 | | | | | | | | | | | | | | | | | |
| **CT** | | | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 696 | 928 | 928 | 928 | 1,160 | 1,392 |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| **DR** | 497 | 507 | 512 | 533 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 |
| **Solar** | 47 | 147 | 147 | 447 | 447 | 447 | 447 | 447 | 697 | 1,097 | 1,497 | 1,897 | 2,297 | 2,497 | 2,897 | 3,147 | 3,325 | 3,525 | 3,725 | 3,925 |
| **Solar & Storage** | | | | | | | | | | | | | | | | | | | | |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | | 200 | 400 | 600 | 800 | 1,000 | 1,200 | 1,400 | 1,600 | 1,800 | 2,000 | 2,200 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

| Hi LF | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gibson 1&2** | 0 | 0 | 0 | 0 | 0 | 0 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Gibson 3** | 0 | 0 | 0 | 0 | 0 | 0 | -635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Gibson 5** | 0 | 0 | 0 | 0 | 313 | 313 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Capacity PPAs** | 0 | 0 | 50 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **CT** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 464 | 464 | 464 | 464 | 696 | 928 |
| **EE** | 0 | 0 | 0 | 0 | 0 | 0 | -1 | -3 | -5 | -6 | -8 | -9 | -10 | -11 | -11 | -11 | -11 | -10 | -9 | -8 |
| **Solar** | 0 | 100 | 0 | -100 | -100 | -100 | -100 | -100 | -50 | 0 | 0 | 0 | 0 | -200 | 0 | 50 | 50 | 50 | 50 | 50 |
| **Solar & Storage** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 |
| **Wind (incl Benton)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 |

## LOW LOAD

Our analysis of optimized portfolios indicates that major new capacity additions will be driven largely by coal retirements rather than by load growth. Therefore, we expect that the risk of over-building capacity is relatively low. However, because capacity additions cannot be undone, the decision to build carries more risk than the decision to wait.

This sensitivity evaluates how an optimized portfolio would change if a lower load forecast is assumed. The tables below show the new optimized portfolio as well as the changes from the portfolio optimized for the Reference with $CO_2$ Regulation scenario.

| Low LF | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Cayuga 1&2** | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| **Edwardsport IGCC** | 618 | 618 | | | | | | | | | | | | | | | | | | |
| **Edwardsport CC** | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| **Gibson 1&2** | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | 635 | 635 | 635 | | | | | | | | | | |
| **Gibson 3** | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | | | |
| **Gibson 4** | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| **Gibson 5** | 313 | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | |
| **Noble CC** | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| **ZELFR** | | | | | | | | | | | | | | | | | | | | |
| **CC 1** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **CC 2 & 3** | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| **Capacity PPAs** | | 200 | 450 | | | | | | | | | | | | | | | | | |
| **CT** | | | | | | | | | | | | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 |
| **EE** | 53 | 85 | 119 | 151 | 178 | 207 | 249 | 268 | 292 | 315 | 334 | 345 | 355 | 363 | 380 | 374 | 365 | 358 | 355 | 351 |
| **DR** | 497 | 507 | 512 | 533 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 |
| **Solar** | 47 | 47 | 197 | 597 | 597 | 597 | 647 | 647 | 747 | 1,147 | 1,547 | 1,947 | 2,347 | 2,697 | 2,897 | 3,147 | 3,325 | 3,525 | 3,725 | 3,925 |
| **Solar & Storage** | | | | | | | | | | | | | | | | | | | | |
| **Wind (incl Benton)** | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 50 | 100 | 300 | 500 | 700 | 900 | 1,100 | 1,300 | 1,500 | 1,700 | 1,900 | 2,100 | 2,300 |
| **Storage** | | | | | | | | | | | | | | | | | | | | |

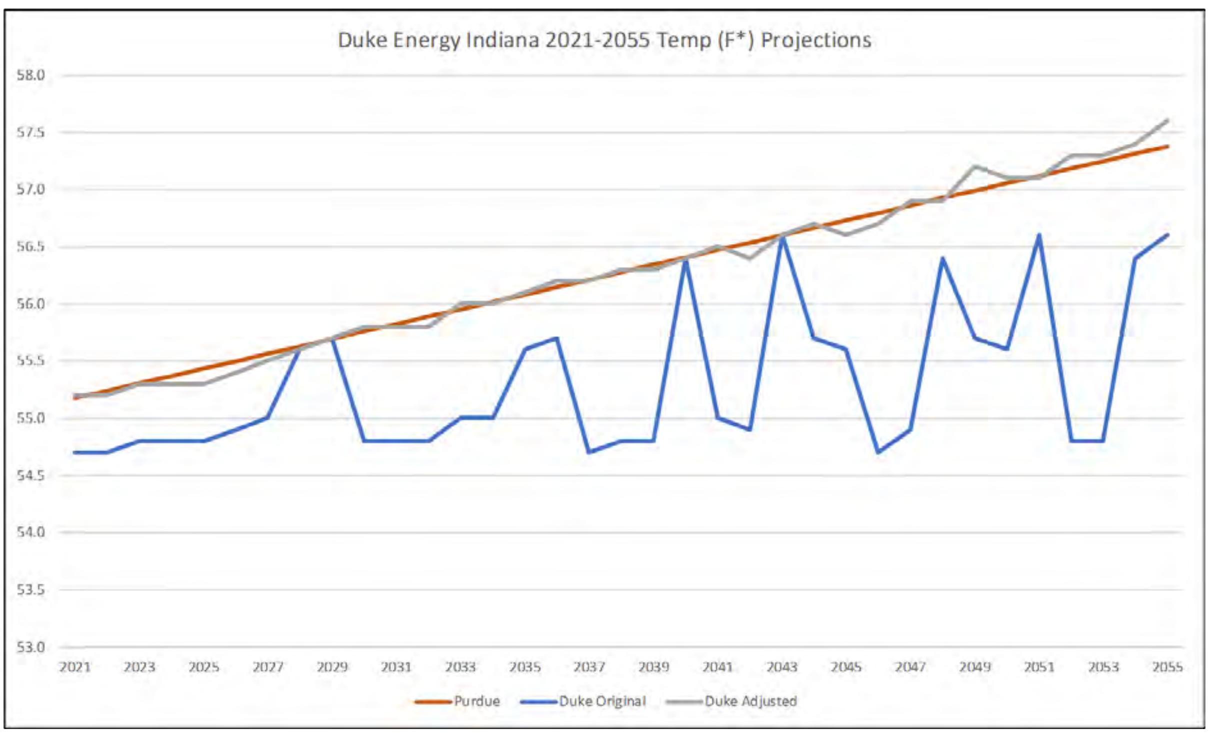
| Low LF | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gibson 3** | 0 | 0 | 0 | 0 | 0 | 0 | -635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Gibson 5** | 0 | 0 | 0 | 0 | 313 | 313 | 313 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **CT** | 0 | 0 | -232 | -232 | -232 | -232 | -232 | -232 | -232 | -232 | -232 | 0 | 0 | 0 | 0 | -232 | -232 | -232 | -232 | -232 |
| **EE** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 3 | 3 | 4 | 5 |
| **Solar** | 0 | 0 | 50 | 50 | 50 | 50 | 100 | 100 | 0 | 50 | 50 | 50 | 50 | 0 | 0 | 50 | 50 | 50 | 50 | 50 |
| **Solar & Storage** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 |

The result of this analysis is that there is a reduction in CT capacity partially offset by an increase in solar.

Changes in load forecast will be part of the regular update of assumptions and included in future IRPs.

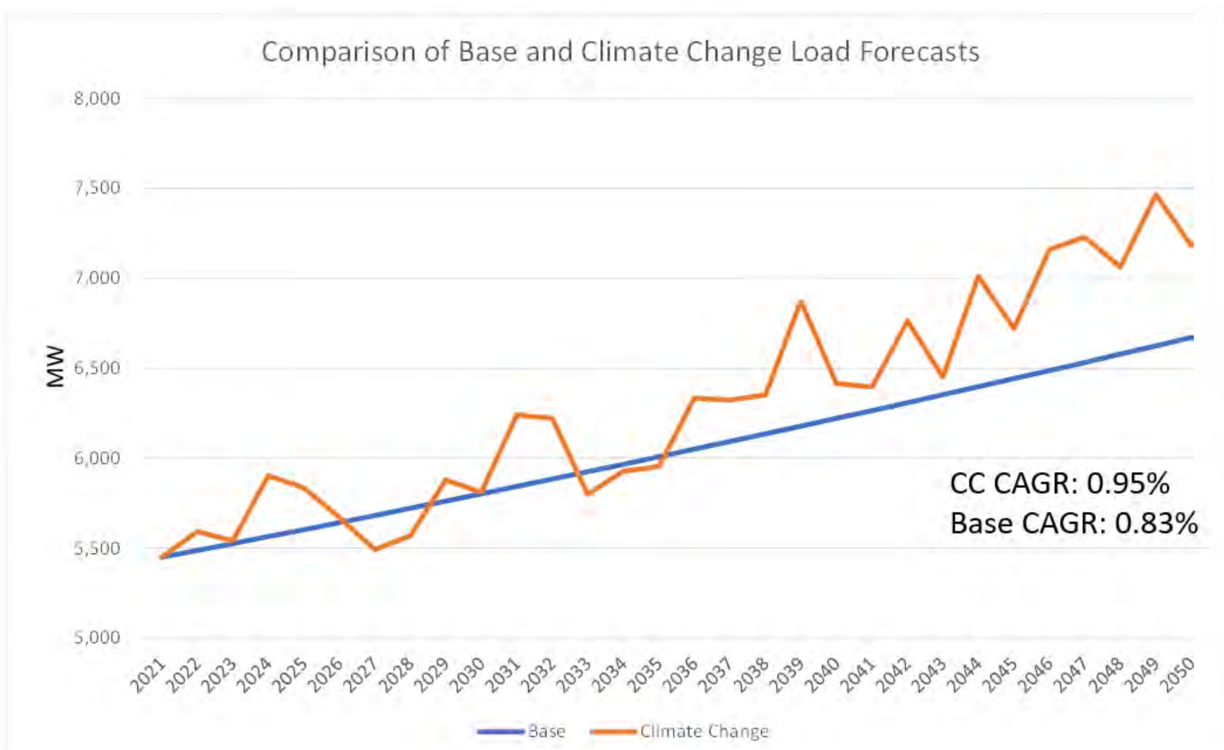
## CLIMATE CHANGE LOAD

Based on stakeholder comments about factoring in the effects of climate change on load, we reached out to a Purdue professor (Dr. Roshanak Nateghi) to discuss her work on this issue. Building on historical data using higher temperature years, our meteorologists scaled up this data to come up with a temperature forecast that approximated the Intergovernmental Panel on Climate Change's (IPCC) Representative Concentration Pathway (RCP) 4.5 trajectory and is represented in the chart below.



Our load forecasters then took the higher temperature forecast to develop a corresponding load forecast that is shown below. It is interesting to note that the change in temperature does not drive a significant change in peak demand, nor does it drive a significant change on the overall load.  This is because when summertime temperatures are a few degrees higher than normal, there is not an extreme increase in peak demand. And on the load side, while summers are on average hotter, the late fall, winter and early spring are milder.

The takeaway from this exercise is that a higher temperature forecast is not a material driver in the load forecasting for resource planning. Shifting our focus to how weather variability and extremes due to climate change will affect resource planning and reliability will be investigated leading up to the 2024 IRP.



## REQUEST FOR INFORMATION (RFI) DATA

At the request of stakeholders, at the beginning of the IRP process, Duke Energy Indiana conducted an RFI to test the market for renewable resources. The RFI Data sensitivity tests the optimal portfolios given the RFI results. Using the data from the responses to the RFI, a cost reduction of 15% for solar was used based on the median of the responses. That cost data was added to the MISO level modeling and a new portfolio of the MISO fleet was determined and dispatched to come up with power prices that reflect lower costs of this sensitivity.

Those power prices were then used to re-optimize a portfolio which was then compared to the optimized portfolio for the Reference with $CO_2$ Regulation scenario. The table below shows the details of the portfolio optimized using RFI data and then shows the changes.

| RFI Port | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cayuga 1&2 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| Edwardsport IGCC | 618 | 618 | | | | | | | | | | | | | | | | | | |
| Edwardsport CC | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| Gibson 1&2 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | 635 | 635 | | | | | | | | | |
| Gibson 3 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | | | |
| Gibson 4 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| Gibson 5 | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| Noble CC | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| ZELFR | | | | | | | | | | | | | | | | | | | | |
| CC 1 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| CC 2 & 3 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| Capacity PPAs | 50 | 250 | 500 | | | | | | | | | | | | | | | | | |
| CT | | | | | | | | | | | | | 232 | 232 | 464 | 464 | 464 | 464 | 696 | 696 |
| EE | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 369 | 363 | 355 | 348 | 346 | 343 |
| DR | 497 | 507 | 512 | 533 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 |
| Solar | 47 | 47 | 297 | 697 | 697 | 697 | 697 | 697 | 1,097 | 1,497 | 1,897 | 2,297 | 2,547 | 2,747 | 2,947 | 3,147 | 3,325 | 3,525 | 3,725 | 3,925 |
| Solar & Storage | | | | | | | | | | | | | | | | | | | | |
| Wind (incl Benton) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | | 200 | 400 | 600 | 800 | 1,000 | 1,200 | 1,400 | 1,600 | 1,800 | 2,000 | 2,200 |
| Storage | | | | | | | | | | | | | | | | | | | | |

| RFI Delta | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gibson 1&2 | 0 | 0 | 0 | 0 | 0 | 0 | 635 | 635 | 0 | 0 | 635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gibson 3 | 0 | 0 | 0 | 0 | 0 | 0 | -635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gibson 5 | 0 | 0 | 0 | 0 | 313 | 313 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capacity PPAs | 0 | 0 | 50 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CT | 0 | 0 | -232 | -232 | -232 | -232 | -232 | -232 | -232 | -232 | -232 | -232 | 0 | 0 | 232 | 0 | 0 | 0 | 232 | 232 |
| EE | 0 | 0 | 0 | 0 | 0 | 0 | -1 | -3 | -5 | -6 | -8 | -9 | -10 | -11 | -10 | -9 | -8 | -6 | -4 | -3 |
| Solar | 0 | 0 | 150 | 150 | 150 | 150 | 150 | 150 | 350 | 400 | 400 | 400 | 250 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Solar & Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 |
| Wind (incl Benton) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 | -100 |

The results of this analysis generally delayed some coal retirements and reduced CT and wind generation, while adding more solar.

## HIGH CAPITAL COST GAS GENERATION

The High Capital Cost Gas Generation sensitivity was requested by a stakeholder to include view where the capital cost of new gas generation is higher than the reference cases.

In this sensitivity, the cost of gas generation was increased 20% which was included in the MISO level forecast to develop new power prices that we then used to develop an optimized portfolio. The details of this analysis are shown below.

| High Gas Gen Cost | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cayuga 1&2 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | | | | | | | | | | | | | | |
| Edwardsport IGCC | 618 | 618 | | | | | | | | | | | | | | | | | | |
| Edwardsport CC | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| Gibson 1&2 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | | | | | | | | | | | | | |
| Gibson 3 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | |
| Gibson 4 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| Gibson 5 | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | | | |
| Noble CC | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| ZELFR | | | | | | | | | | | | | | | | | | | | |
| CC 1 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| CC 2 & 3 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| Capacity PPAs | 50 | 250 | 400 | | | | | | | | | | | | | | | | | |
| CT | | | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 464 | 464 | 464 | 464 | 464 |
| EE | 53 | 85 | 119 | 154 | 184 | 216 | 258 | 277 | 298 | 317 | 334 | 344 | 353 | 359 | 375 | 367 | 357 | 350 | 348 | 345 |
| DR | 497 | 507 | 512 | 533 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 | 538 |
| Solar | 47 | 47 | 47 | 347 | 347 | 347 | 347 | 597 | 747 | 1,147 | 1,547 | 1,947 | 2,347 | 2,747 | 2,947 | 3,147 | 3,325 | 3,525 | 3,725 | 3,925 |
| Solar & Storage | | | | | | | | | | | | | | | | | | | | |
| Wind (incl Benton) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | 150 | 350 | 550 | 750 | 950 | 1,150 | 1,350 | 1,550 | 1,750 | 1,950 | 2,150 | 2,350 |
| Storage | | | | | | | | | | | | | | | | | | | | |

| Hi Gas Gen $ Delta | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Gibson 1&2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -635 | -635 | -635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gibson 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 635 | 635 | 635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gibson 5 | 0 | 0 | 0 | 0 | 313 | 313 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capacity PPAs | 0 | 0 | -50 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EE | 0 | 0 | 0 | 2 | 6 | 9 | 10 | 8 | 5 | 3 | 0 | -1 | -2 | -4 | -5 | -5 | -5 | -4 | -3 | -1 |
| Solar | 0 | 0 | -100 | -200 | -200 | -200 | -200 | 50 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Solar & Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 |
| Wind (incl Benton) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |

It is noteworthy that despite the higher capital cost of gas generation, the combined cycles in 2027 remained in the plan, which is indicative of the need for a higher capacity factor resource.

## HIGHER WINTER WIND EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)

The sensitivity for Higher Winter Wind ELCC tests the impact of increasing the winter ELCC for wind. This sensitivity supports the MISO move to a more seasonal construct, and while not finalized, will likely include a winter reserve margin requirement. In this sensitivity, the contribution to peak for wind was increased in the winter to 20% which is more accurate and in line with the principles of a seasonal construct.

Like previous sensitivities, the higher winter wind ELCC was included in the MISO level modeling to develop a new power price forecast, which was then used for Duke Energy Indiana level modeling with the results shown below.

| Wind ELCC | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cayuga 1&2 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 1,005 | 500 | 500 | 500 | 500 | | | | | | | | | | |
| Edwardsport IGCC | 618 | 618 | | | | | | | | | | | | | | | | | | |
| Edwardsport CC | | | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 | 586 |
| Gibson 1&2 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 1,270 | 635 | | | | | | | | | | | | | |
| Gibson 3 | 635 | 635 | 635 | 635 | 635 | 635 | | | | | | | | | | | | | | |
| Gibson 4 | 627 | 627 | 627 | 627 | 627 | 627 | | | | | | | | | | | | | | |
| Gibson 5 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | 313 | | | | | | | | | | | | |
| Noble CC | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | 310 | | | | | | |
| ZELFR | | | | | | | | | | | | | | | | | | | | |
| CC 1 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| CC 2 & 3 | | | | | | | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| Capacity PPAs | 50 | 250 | 450 | | | | | | | | | | | | | | | | | |
| CT | | | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 | 232 |
| EE | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| DR | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 |
| Solar | 47 | 47 | 147 | 347 | 347 | 347 | 347 | 347 | 747 | 1,147 | 1,547 | 1,947 | 2,347 | 2,747 | 2,947 | 3,147 | 3,325 | 3,525 | 3,725 | 3,875 |
| Solar & Storage | | | | | | | | | | | | | | | | | | | | 75 |
| Wind (incl Benton) | 100 | 100 | 100 | 100 | 100 | 100 | 100 | | 150 | 350 | 550 | 750 | 950 | 1,150 | 1,350 | 1,550 | 1,750 | 1,950 | 2,150 | 2,350 |
| Storage | | | | | | | | | | | | | | | | | | | | |

| Wind ELCC Delta | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cayuga 1&2 | 0 | 0 | 0 | 0 | 0 | 0 | 500 | 500 | 500 | 500 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gibson 1&2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -635 | -635 | -635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gibson 3 | 0 | 0 | 0 | 0 | 0 | 0 | -635 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gibson 5 | 0 | 0 | 0 | 0 | 313 | 313 | 313 | 313 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -232 | -232 | -232 | -232 | -232 |
| EE | 0 | 0 | 0 | 0 | 0 | 0 | -1 | -3 | -5 | -6 | -8 | -9 | -10 | -11 | -11 | -11 | -11 | -10 | -9 | -8 |
| DR | 0 | 0 | 0 | 74 | 75 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 | 76 |
| Solar | 0 | 0 | 0 | -200 | -200 | -200 | -200 | -200 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 0 |
| Solar & Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | -75 | 0 |
| Wind (incl Benton) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |

This sensitivity resulted in the addition of a modest amount of wind starting in 2029. It also modified some coal retirements and decreased early solar additions and later CT additions.

## UPSTREAM GREENHOUSE GAS & SOCIAL COST OF CARBON

The sensitivity for Upstream Greenhouse Gas was also requested by a stakeholder. This is a difficult analysis to scope as it becomes a question of how far back in the supply chain do we track greenhouse gases. For this analysis, we included methane releases associated with the mining of coal and the extraction and transportation of natural gas. Methane is more potent greenhouse gas (GHG) than $CO_2$.

This analysis does not include GHG emissions associated with the transport of coal or the mining of materials that go into the manufacturing of solar, wind, battery, and gas turbine equipment. The table below shows the portfolios on the left-hand side and in the first two columns of data, there are $CO_2$ emissions from Duke Energy Indiana generating assets compared to the $CO_2$ equivalent ($CO_2$e) emissions when methane is factored in as described above.

At the request of stakeholders, we performed a Social Cost of Carbon sensitivity. For this sensitivity, we took the carbon emissions for each portfolio in the Reference with $CO_2$ Regulation scenario and applied the Social Cost of Carbon to each portfolios PVRR. In the two far right columns of the table below, the baseline PVRRs are shown with the added cost of the social cost of carbon resulting in an increase of 50%-100% versus the Reference with $CO_2$ Regulation scenario.

| | | | | METRICS | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | 2040 DEI Gen $CO_2$ Emissions (K Tons) | 2040 DEI Gen $CO_2e$ Emissions with Methane (K Tons) | | 2040 PVRR (b$) | 2040 PVRR with Social Cost of Carbon (b$) |
| PORTFOLIOS | Optimized | 1 | Ref w/o $CO_2$ Reg | 4,059 | 5,552 | | $15.3 | $27.4 |
| PORTFOLIOS | Optimized | 2 | Ref w/ $CO_2$ Reg | 7,012 | 9,592 | | $15.6 | $27.7 |
| PORTFOLIOS | Optimized | 3 | High Gas Prices | 1,012 | 1,385 | | $15.8 | $26.6 |
| PORTFOLIOS | Optimized | 4 | Low Gas Prices | 10,030 | 13,720 | | $15.1 | $29.0 |
| PORTFOLIOS | Hybrid | 5 | Balanced Hybrid | 13,110 | 15,517 | | $17.1 | $35.7 |
| PORTFOLIOS | Hybrid | 6 | Renewables/CC Hybrid | 6,052 | 8,279 | | $18.5 | $34.3 |
| PORTFOLIOS | Hybrid | 7 | Renewables/CC/CT Hybrid | 4,075 | 5,575 | | $17.4 | $32.6 |
| PORTFOLIOS | Hybrid | 8 | Renewables/CT Hybrid | 3,009 | 4,116 | | $18.7 | $33.6 |
| PORTFOLIOS | Stakeholder | 9 | Biden 100 | 0 | 0 | | $20.9 | $31.3 |
| PORTFOLIOS | Stakeholder | 10 | Biden 90 | 2,225 | 3,043 | | $19.8 | $30.9 |
| PORTFOLIOS | Stakeholder | 11 | Enviro Focused | 999 | 1,366 | | $18.4 | $28.4 |
| PORTFOLIOS | Stakeholder | 12 | Reliable Energy | 8,932 | 10,439 | | | |

SECTION VI

# PREFERRED PORTFOLIO FOR THE 2021 INTEGRATED RESOURCE PLAN

## A. PREFERRED PORTFOLIO

The Company has selected the Renewables-CC-CT portfolio described in Chapter V as the preferred portfolio for the 2021 IRP. The capacity and energy mixes for this portfolio are shown below. Based on the results of our analysis discussed in Section V, we have concluded that this portfolio best balances the objectives of the 2021 IRP. Figure VI.3 shows the range of outcomes for the Renewables-CC-CT portfolio across all scenarios (blue) embedded in the range of outcomes for all portfolios across all scenarios (gray) under the three key objectives we targeted for this IRP. The costs (present value revenue requirements (PVRR)) of this portfolio fall near the middle of the range for all portfolios, while the market exposure (portion of total energy demand served by the market by the end of the planning period) falls near the bottom of the range and the carbon emissions reduction (by the end of the planning period against the 2005 baseline) falls near the top of the range for all portfolios. Under the Renewables-CC-CT portfolio, the resource mix will be diversified over time without committing to dramatic resource changes prematurely, preserving decision-making flexibility going into the 2024 IRP analysis and shielding customers from undue cost increases in the near-term.

FIGURE VI.1
CAPACITY MIX OF PREFERRED PORTFOLIO

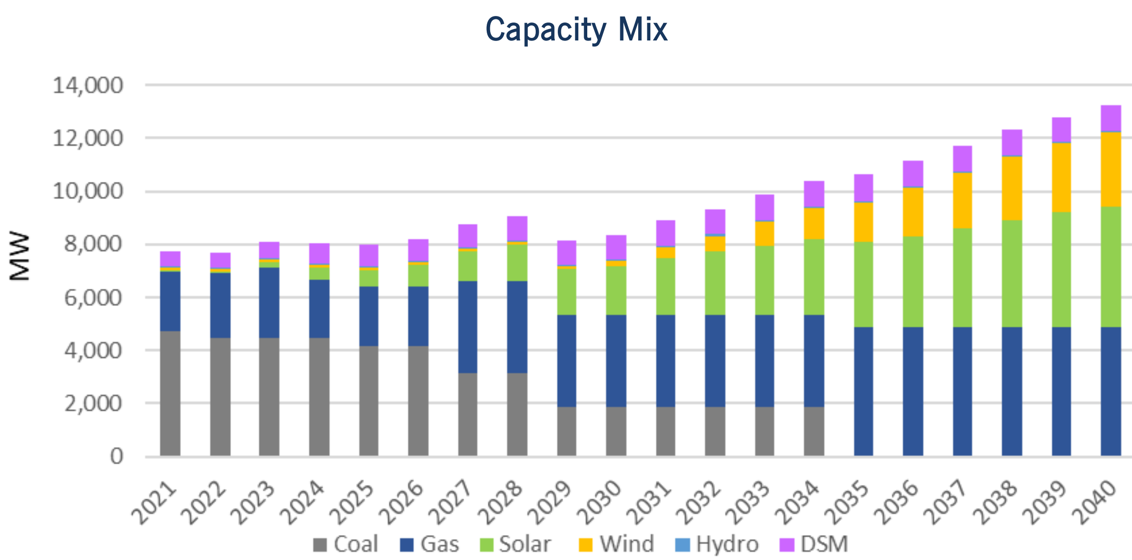



FIGURE VI.2
ENERGY MIX OF PREFERRED PORTFOLIO IN REFERENCE W/$CO_2$ REGULATION SCENARIO

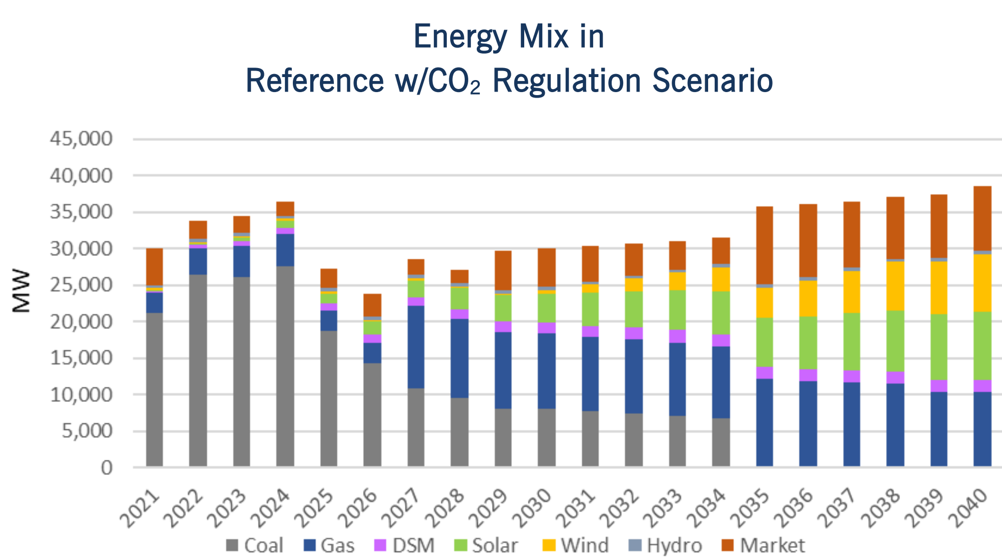
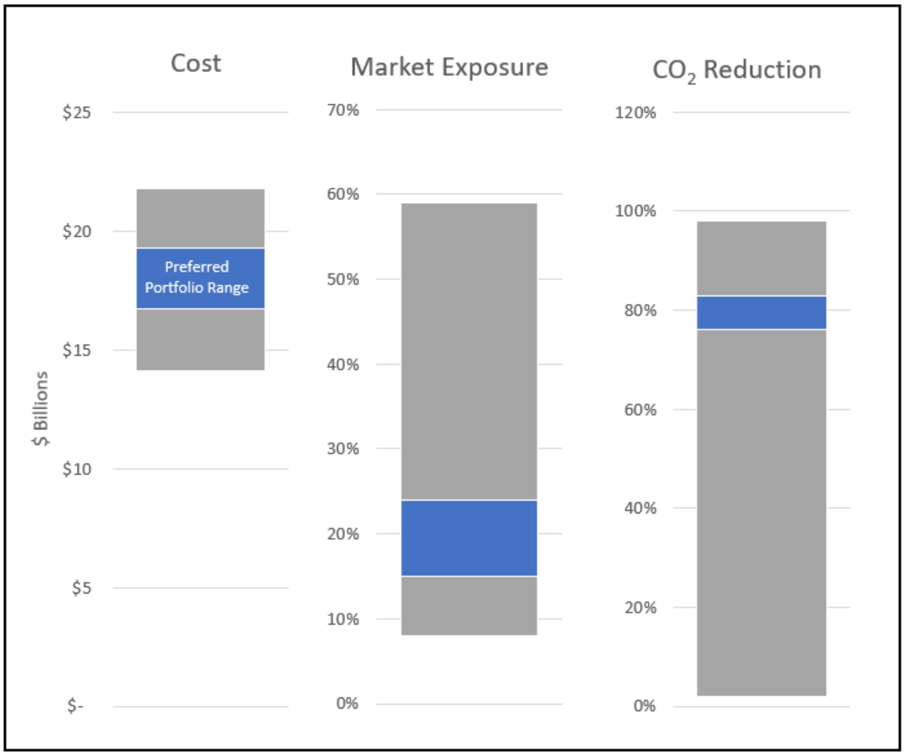


FIGURE VI.1
PERFORMANCE OF RENEWABLES-CC-CT PORTFOLIO ACROSS ALL SCENARIOS WITH RESPECT TO MAIN IRP OBJECTIVES (BLUE) WITHIN RANGE OF PERFORMANCE FOR ALL PORTFOLIOS ACROSS ALL SCENARIOS (GRAY)




In the 2021 IRP, Duke Energy Indiana used predetermined decision criteria to assist in its ultimate selection of the preferred portfolio. The decision criteria were based in large part on the energy policy priorities outlined in the 21st Century Energy Policy Taskforce Report from the General Assembly issued in 2020: Reliability, Resilience/Stability, Affordability, Environmental Sustainability and Portfolio Flexibility. Much of the criteria can be measured quantitatively, such as meeting capacity and energy requirements for reliability, customer rate impact and carbon reductions; however, some criteria are more qualitative in nature, such as flexibility and executability. The scorecard shown below compiles that information.

# TABLE VI.1
# IRP SELECTION CRITERIA

| | | | Reliability | | | Resilience / Stability | | | Affordability | | Environmental Sustainability | | | Portfolio Flexibility |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | METRIC | Dispatchable Resources as a percentage of load[1] | Can portfolio serve load in all years of IRP planning period?[2] | Average percentage of annual market purchases[3] | Diversity of Resources as measured by HHI[4] | Executability[5] | Can portfolio mix serve load in extreme weather weeks in PST?[6] | Average of portfolio PVRRs across scenarios[7] | 5 year CAGR of rates in Ref Scenario w/o CO2[8] | 2040 CO2 Reduction % and Avg Annual Tons Emitted[9] | On track for meeting Duke Energy Climate Goals?[10] | SO2, NOx, PM & Water Emissions[11] | Range of PVRRs across scenarios[12] |
| | | | Higher better | <5% Acceptable | <20-25% preferred | Lower better | | | Lower better | Lower better | Greater reducton better | | | Smaller better |
| PORTFOLIOS – Optimized | 1 | Ref w/o CO2 Reg | 115% | 0.24% | 25% | 25% | ● | ● | $16.1 | 0.8% | -47% | No | ◑ | $3.6 |
| | 2 | Ref w/ CO2 Reg | 104% | 0.36% | 16% | 25% | ◕ | ◕ | $16.1 | 0.8% | -74% | No | ◕ | $3.9 |
| | 3 | High Gas Prices | 117% | 0.13% | 31% | 31% | ● | ● | $16.5 | 0.9% | -43% | No | ◔ | $4.2 |
| | 4 | Low Gas Prices | 118% | 0.28% | 15% | 43% | ● | ● | $15.8 | 0.6% | -48% | No | ◑ | $4.9 |
| Hybrid | 5 | Balanced Hybrid | 115% | 0.06% | 9% | 19% | ◕ | ◕ | $17.5 | 1.4% | -40% | No | ◔ | $1.8 |
| | 6 | Renewables/CC Hybrid | 108% | 0.08% | 7% | 15% | ◑ | ● | $18.7 | 2.0% | -78% | Yes | ◑ | $2.0 |
| | 7 | Renewables/CC/CT Hybrid | 91% | 0.23% | 19% | 17% | ◕ | ◑ | $18.0 | 1.3% | -78% | Yes | ◑ | $2.6 |
| | 8 | Renewables/CT Hybrid | 110% | 0.05% | 17% | 18% | ◑ | ● | $19.3 | 2.0% | -82% | Yes | ◑ | $2.3 |
| Stakeholder | 9 | Biden 100 | 102% | 0.06% | 12% | 17% | ◔ | ◕ | $21.0 | 1.7% | -96% | Yes | ◕ | $1.3 |
| | 10 | Biden 90 | 97% | 0.26% | 13% | 17% | ◔ | ◕ | $20.0 | 1.5% | -90% | Yes | ◕ | $1.7 |
| | 11 | Enviro Focused | 84% | 3.70% | 41% | 18% | ◑ | ◑ | $19.3 | 1.1% | -79% | Yes | ◕ | $3.8 |
| | 12 | Reliable Energy | 98% | 0.08% | 12% | 19% | ◑ | ◑ | Note 13 | | -64% | No | ◑ | Note 13 |

| ○ | ◔ | ◑ | ◕ | ● |
|---|---|---|---|---|
| Poor | Fair | Good | Very Good | Excellent |

**Notes**

1. (Coal, Gas & Battery MW in 2030) / (Total MW in 2030)
2. Average of Energy Not Served / Total Energy for all years in all scenarios (<.5% due to outages in model)
3. Average of market purchases in all years in all scenarios
4. HHI is a concentration index calculated by adding square of each resources percentage on a MW basis
5. Greater construction level though 2030 drive this metric
6. Applies 2030 portfolio mix to extreme weather weeks in PST
7. Averages PVRRs across all scenarios
8. Average 5 year rate impact due to generation choices
9. CO2 reduction relative to 2005 and includes CO2 associated with market purchases
10. Are the 2040 CO2 emissions of a portfolio less than a linear interpolation between 2005 and 0 in 2050?
11. Composite of pollutants and water consumption based on 2030 portfolio performance
12. (Max PVRR - Min PVRR) for a portfolio across all scenarios
13. The 5 year rate impact of the Reliable Energy portfolio includes all of the capital for CCS but only 1 year of tax credits: stakeholder asked to exclude with the following context "Reliable Energy (RE) and DEI together developed a portfolio during the stakeholder process (the "RE Portfolio"). DEI developed cost estimates and rate impacts for the RE Portfolio, but upon review RE identified issues regarding the evaluation. Given inadequate time to resolve the issues, the parties agreed to describe the portfolio but omit the associated cost and rate analyses from DEI's IRP materials. DEI notes that it believes that the RE Portfolio was competitive in terms of rate impacts."

# TABLE VI.2
# LOAD, CAPACITY, AND RESERVES FOR PREFERRED PORTFOLIO

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (MW)** | 5,715 | 5,840 | 6,172 | 6,105 | 6,120 | 6,054 | 6,073 | 5,865 | 5,900 | 5,942 | 5,994 | 6,052 | 6,095 | 6,144 | 6,197 | 6,261 | 6,316 | 6,379 | 6,447 | 6,517 |
| **Reductions to Load (MW)** | | | | | | | | | | | | | | | | | | | | |
| EE | 53 | 85 | 119 | 151 | 178 | 207 | 248 | 266 | 288 | 308 | 326 | 336 | 346 | 353 | 368 | 361 | 352 | 345 | 342 | 338 |
| DR | 497 | 507 | 512 | 607 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 | 613 |
| **Adjusted Peak Load (MW)** | 5,165 | 5,248 | 5,541 | 5,346 | 5,329 | 5,234 | 5,213 | 4,986 | 4,999 | 5,021 | 5,055 | 5,103 | 5,137 | 5,178 | 5,216 | 5,286 | 5,351 | 5,421 | 5,492 | 5,566 |
| **System Generating Capacity (Nameplate MW)** | | | | | | | | | | | | | | | | | | | | |
| **Retirements** | | | | | | | | | | | | | | | | | | | | |
| Coal | 280 | 280 | 280 | 280 | 593 | 593 | 1,598 | 1,598 | 2,860 | 2,860 | 2,860 | 2,860 | 2,860 | 2,860 | 4,748 | 4,748 | 4,748 | 4,748 | 4,748 | 4,748 |
| CC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 310 | 310 | 310 | 310 | 310 | 310 |
| CT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Additions** | | | | | | | | | | | | | | | | | | | | |
| CC | 0 | 0 | 0 | 0 | 0 | 0 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 | 1,221 |
| CT & CHP | 0 | 0 | 0 | 0 | 0 | 0 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 1,181 | 1,181 | 1,181 | 1,181 | 1,181 | 1,181 |
| Capacity PPAs | 50 | 250 | 450 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 47 | 47 | 197 | 447 | 647 | 847 | 1,122 | 1,397 | 1,722 | 1,847 | 2,147 | 2,372 | 2,597 | 2,822 | 3,197 | 3,422 | 3,700 | 4,000 | 4,300 | 4,525 |
| Wind | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 200 | 400 | 600 | 900 | 1,200 | 1,500 | 1,800 | 2,100 | 2,400 | 2,600 | 2,800 |
| **Total System Generating Capacity** | 6,525 | 6,403 | 6,791 | 6,699 | 6,705 | 6,849 | 7,180 | 7,374 | 6,492 | 6,618 | 6,795 | 6,925 | 7,067 | 7,208 | 6,997 | 7,133 | 7,308 | 7,478 | 7,639 | 7,758 |
| **Reserve Margin (UCAP)** | | | | | | | | | | | | | | | | | | | | |
| Summer | 9.7% | 9.6% | 10.0% | 9.7% | 9.5% | 13.0% | 18.1% | 25.6% | 9.9% | 11.2% | 13.1% | 14.1% | 15.7% | 17.0% | 12.6% | 13.6% | 15.3% | 16.8% | 18.0% | 18.5% |
| Winter | 41.7% | 31.8% | 35.7% | 24.9% | 21.5% | 25.7% | 29.0% | 28.4% | 13.5% | 14.0% | 14.4% | 16.4% | 14.5% | 14.6% | 9.4% | 9.4% | 12.5% | 12.7% | 9.9% | 9.4% |

## B. SHORT-TERM ACTION PLAN

The Preferred Portfolio provides a measured and responsible approach with accelerated coal retirements, additions of natural gas for continued reliability and progressively adding renewable generation, beginning with solar in the short term. The benefit of this Plan is the flexibility to adjust to changing market and regulatory conditions, as well as a smooth fleet transition to one that is more diverse and less carbon intensive.

In terms of execution, the IRP can be viewed as a foundational element that sets the strategic direction of the generating fleet. Early in 2022, the Company will be issuing a request for proposals (RFP) to gather bid information for the next phase of resources that will be added to the portfolio. Charles River and Associates (CRA) was selected as the independent third-party administrator of the Indiana RFP. The Company intends for CRA to review the bids received and to provide Duke Energy Indiana with its assessment of the top bid projects for further consideration. Duke Energy Indiana reasonably expects to select several generating projects to serve its customers that will be submitted to the Indiana Utility Regulatory Commission for its review and approval under the certificate of public convenience and necessity (CPCN) process.

The IRP will also serve as a reference point for the next Energy Efficiency (EE) filing which will then lead into the next iteration of a cycle that is expected to continue in the following fashion:

| 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|
| IRP | RFP/CPCN | EE | IRP | RFP/CPCN | EE | IRP |

## C. PREFERRED PORTFOLIO'S ABILITY TO ADAPT TO CHANGING CONDITIONS

One of the benefits of increasing the diversity of Duke Energy Indiana's generating fleet is the increased flexibility that can be leveraged in the face of a changing world. Given the measured pace of transition, the Company can adjust its plans accordingly. For example, if load grows more or less than expected, the plan could adjust by accelerating or slowing down implementation of the preferred portfolio. If the relative cost of a resource should change from what is being evaluated in this IRP or certain technologies should develop faster than others, the Company can take advantage of resources with improved economics and move away from those resources whose relative economics have worsened. This could happen due to changes in a resource's capital costs, O&M costs, environmental compliance costs, the pace of technology, or other regulatory requirements.

## D. VARIABLES TO MONITOR AND ONGOING IMPROVEMENTS TO IRP PROCESS

While the preferred portfolio for the 2021 IRP includes resource choices specified through 2040, it is important to remember that resource planning is an ongoing, iterative process. Every three years we reassess the state of our operating environment and adjust our plans accordingly. The IRP will be updated again in 2024, at which time we will adapt the resource selections based on new forecasts and technical, market, and political insights. Key factors to monitor ahead of the 2024 IRP will be:

- Renewable energy and carbon policy at the federal, state and local levels
- The cost trends for solar, wind, and storage
- The evolution of MISO market rules for resource adequacy, renewables and storage
- Natural gas prices

- Technology improvements
- Required transmission investments to accommodate increased renewables


# APPENDIX A

## FINANCIAL & OPERATING FORECASTS FOR PREFERRED PORTFOLIO

# APPENDIX A

# FINANCIAL AND OPERATING FORECASTS FOR PREFERRED PORTFOLIO

## TABLE A.1
## ANNUAL REVENUE REQUIREMENTS OF PREFERRED PORTFOLIO UNDER EACH SCENARIO

| | SCENARIOS | | | |
|---|---|---|---|---|
| YEAR | Ref w/o $CO_2$ Reg | Ref w/ $CO_2$ Reg | High Gas Prices | Low Gas Prices |
| 2021 | $1,149 | $1,147 | $1,177 | $1,155 |
| 2022 | $1,199 | $1,193 | $1,261 | $1,192 |
| 2023 | $1,213 | $1,193 | $1,172 | $1,180 |
| 2024 | $1,214 | $1,211 | $1,233 | $1,161 |
| 2025 | $1,129 | $1,153 | $1,162 | $1,121 |
| 2026 | $1,164 | $1,236 | $1,222 | $1,123 |
| 2027 | $1,371 | $1,439 | $1,526 | $1,320 |
| 2028 | $1,346 | $1,435 | $1,419 | $1,298 |
| 2029 | $1,453 | $1,538 | $1,594 | $1,354 |
| 2030 | $1,496 | $1,641 | $1,698 | $1,421 |
| 2031 | $1,529 | $1,712 | $1,755 | $1,461 |
| 2032 | $1,566 | $1,755 | $1,809 | $1,505 |
| 2033 | $1,650 | $1,850 | $1,834 | $1,592 |
| 2034 | $1,854 | $2,074 | $2,049 | $1,805 |
| 2035 | $1,919 | $2,152 | $2,355 | $1,767 |
| 2036 | $1,995 | $2,234 | $2,435 | $1,844 |
| 2037 | $2,102 | $2,330 | $2,550 | $1,950 |
| 2038 | $2,204 | $2,422 | $2,630 | $2,056 |
| 2039 | $2,266 | $2,516 | $2,720 | $2,108 |
| 2040 | $2,357 | $2,600 | $2,826 | $2,195 |

## TABLE A.2
## LEVELIZED PVRR ($/KWH) OF CANDIDATE PORTFOLIO IN REFERENCE WITH $CO_2$ REGULATION SCENARIO

| Portfolio | PVRR $/kWh |
|---|---|
| Ref w/o $CO_2$ Reg | $0.044 |
| Ref w/ $CO_2$ Reg | $0.041 |
| High Gas Prices | $0.047 |
| Low Gas Prices | $0.040 |
| Balanced Hybrid | $0.046 |
| Renewables/CC Hybrid | $0.047 |
| **Renewables/CC/CT Hybrid** | **$0.047** |
| Renewables/CT Hybrid | $0.050 |
| Biden 100 | $0.053 |
| Biden 90 | $0.050 |
| Enviro Focused | $0.052 |

**Note:** IRP PVRR excludes all existing generation, transmission, and distribution rate base as well as unavoidable future expenditures. It would not be appropriate to compare these figures to market energy prices or utility rates.

## TABLE A.3
## FUEL PRICE FORECAST BY GENERATING STATION (EXISTING UNITS, $/MMBTU) [CONFIDENTIAL]

These are annual fuel cost divided by annual MMbtus for years when the generating unit operated.

| | COAL | | | | NATURAL GAS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Gallagher | Cayuga | Gibson | Edwardsport | Noblesville | Henry County | Madison | Wheatland | Vermillion | Cayuga | Edwardsport |
| 2021 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2022 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2023 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2024 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2025 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | |
| 2026 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | |
| 2027 | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | |
| 2028 | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | | |
| 2029 | | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | | |
| 2030 | | | [redacted] | [redacted] | [redacted] | [redacted] | | | | | |
| 2031 | | | [redacted] | [redacted] | [redacted] | [redacted] | | | | | |
| 2032 | | | [redacted] | [redacted] | [redacted] | [redacted] | | | | | |
| 2033 | | | [redacted] | [redacted] | [redacted] | [redacted] | | | | | |
| 2034 | | | [redacted] | [redacted] | [redacted] | [redacted] | | | | | |
| 2035 | | | | | | [redacted] | | | | | [redacted] |
| 2036 | | | | | | [redacted] | | | | | [redacted] |
| 2037 | | | | | | [redacted] | | | | | [redacted] |
| 2038 | | | | | | [redacted] | | | | | [redacted] |
| 2039 | | | | | | | | | | | [redacted] |
| 2040 | | | | | | | | | | | [redacted] |

TABLE A.4

## Projected Air Emissions and Water Usage for Existing and Potential New Units in Reference with $CO_2$ Regulation Scenario

| | Air Emissions and Water Usage - Existing Units | | | | | | Air Emissions and Water Usage - Potential New Units | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Water | | | | | | Water | |
| | $CO_2$ | Nox | $SO_2$ | Mercury | Consumed | Discharged | $CO_2$ | Nox | $SO_2$ | Mercury | Consumed | Discharged |
| Year | kTons | kTons | kTons | Pounds | Mgal | Mgal | kTons | kTons | kTons | Pounds | Mgal | Mgal |
| 2021 | 24,358 | 10.4 | 12.5 | 70 | 6,555 | 229,207 | 72 | 0.0 | - | - | 0 | 0 |
| 2022 | 30,058 | 13.0 | 17.2 | 89.6 | 7,807 | 311,099 | 55 | 0.0 | - | - | 0 | 0 |
| 2023 | 29,852 | 11.8 | 16.6 | 89.2 | 7,431 | 285,933 | 78 | 0.0 | - | - | 0 | 0 |
| 2024 | 31,921 | 11.9 | 17.8 | 94.0 | 7,754 | 306,596 | 126 | 0.0 | - | - | 0 | 0 |
| 2025 | 21,518 | 7.7 | 9.9 | 58.7 | 6,499 | 183,525 | 21 | 0.0 | - | - | 0 | 0 |
| 2026 | 17,016 | 5.2 | 6.1 | 41.3 | 6,112 | 142,852 | 30 | 0.0 | - | - | 0 | 0 |
| 2027 | 12,991 | 2.4 | 4.3 | 26.7 | 6,689 | 8,939 | 3,378 | 0.2 | - | - | 1,903 | 476 |
| 2028 | 11,713 | 2.0 | 3.9 | 23.4 | 6,584 | 8,087 | 3,362 | 0.2 | - | - | 1,916 | 468 |
| 2029 | 9,809 | 1.6 | 2.4 | 16.5 | 6,547 | 7,083 | 3,344 | 0.2 | - | - | 1,913 | 467 |
| 2030 | 9,715 | 1.5 | 2.4 | 16.3 | 6,538 | 7,034 | 3,308 | 0.2 | - | - | 1,897 | 464 |
| 2031 | 9,423 | 1.4 | 2.3 | 15.4 | 6,467 | 6,838 | 3,233 | 0.2 | - | - | 1,857 | 454 |
| 2032 | 9,136 | 1.3 | 2.2 | 14.6 | 6,422 | 6,548 | 3,250 | 0.2 | - | - | 1,867 | 456 |
| 2033 | 8,776 | 1.3 | 2.1 | 14.0 | 6,336 | 6,307 | 3,282 | 0.2 | - | - | 1,886 | 461 |
| 2034 | 8,391 | 1.2 | 2.0 | 13.4 | 6,247 | 5,973 | 3,259 | 0.2 | - | - | 1,874 | 458 |
| 2035 | 1,617 | 0.0 | 0.0 | | 4,760 | 1,126 | 3,233 | 0.2 | - | - | 1,863 | 455 |
| 2036 | 1,503 | 0.0 | 0.0 | | 4,730 | 1,081 | 3,203 | 0.2 | - | - | 1,847 | 452 |
| 2037 | 1,473 | 0.0 | 0.0 | | 4,724 | 1,067 | 3,185 | 0.2 | - | - | 1,838 | 449 |
| 2038 | 1,429 | 0.0 | 0.0 | | 4,675 | 1,041 | 3,141 | 0.2 | - | - | 1,815 | 443 |
| 2039 | 1,020 | 0.0 | 0.0 | | 4,537 | 857 | 3,084 | 0.2 | - | - | 1,784 | 436 |
| 2040 | 993 | 0.0 | 0.0 | | 4,531 | 840 | 3,083 | 0.2 | - | - | 1,783 | 436 |

## TABLE A.5
## EMISSIONS ALLOWANCES AND $CO_2$ PRICE FORECASTS [CONFIDENTIAL]

| | NOx and $SO_2$ Price Forecasts ($/ton) | | | $CO_2$ Price Forecasts ($/ton) |
|---|---|---|---|---|
| Year | Annual NOx | Seasonal NOx[i] | Annual $SO_2$ | Reference |
| 2021 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2022 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2023 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2024 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2025 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2026 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2027 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2028 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2029 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2030 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2031 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2032 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2033 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2034 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2035 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2036 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2037 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2038 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2039 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2040 | [redacted] | [redacted] | [redacted] | [redacted] |

[i] Seasonal NOx allowances cover May-September of each year.

DUKE ENERGY INDIANA

# APPENDIX B

## LOAD FORECAST

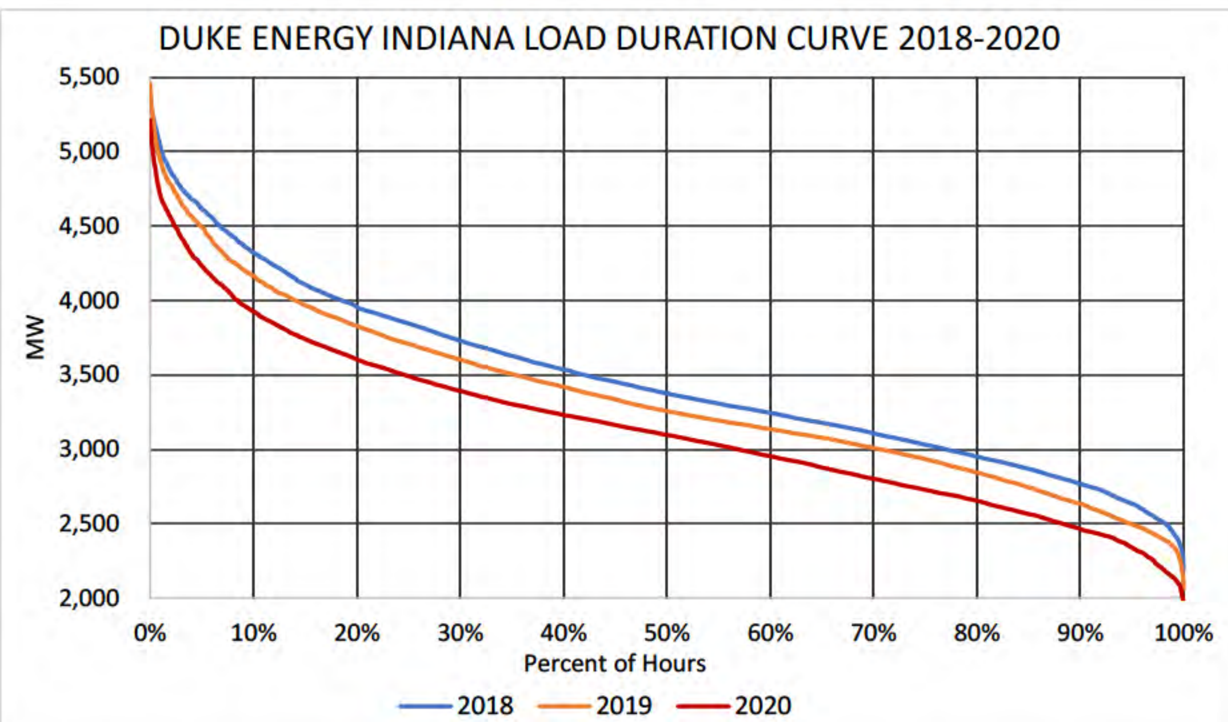
# APPENDIX B

## LOAD FORECAST

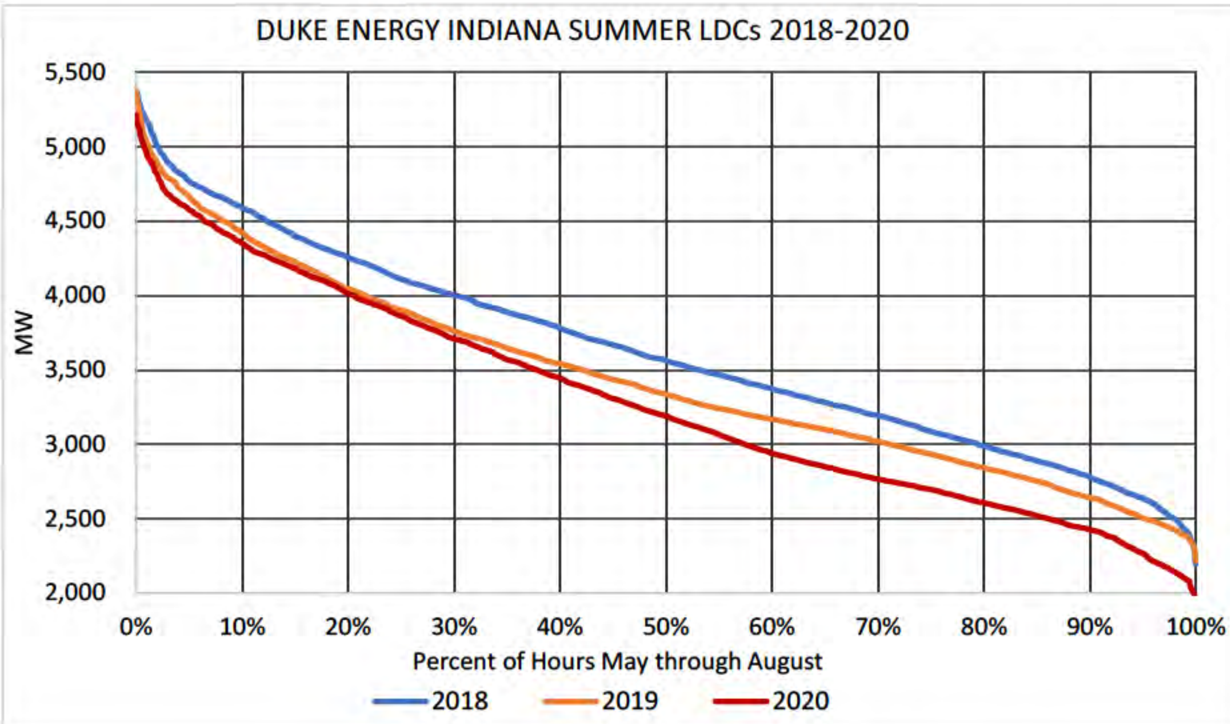
The Load Forecast Dataset to develop this IRP is voluminous in nature. This data will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours and upon execution of an appropriate confidentiality agreement or protective order, if applicable. Please contact Beth Heneghan at 317-837-1254 for more information.

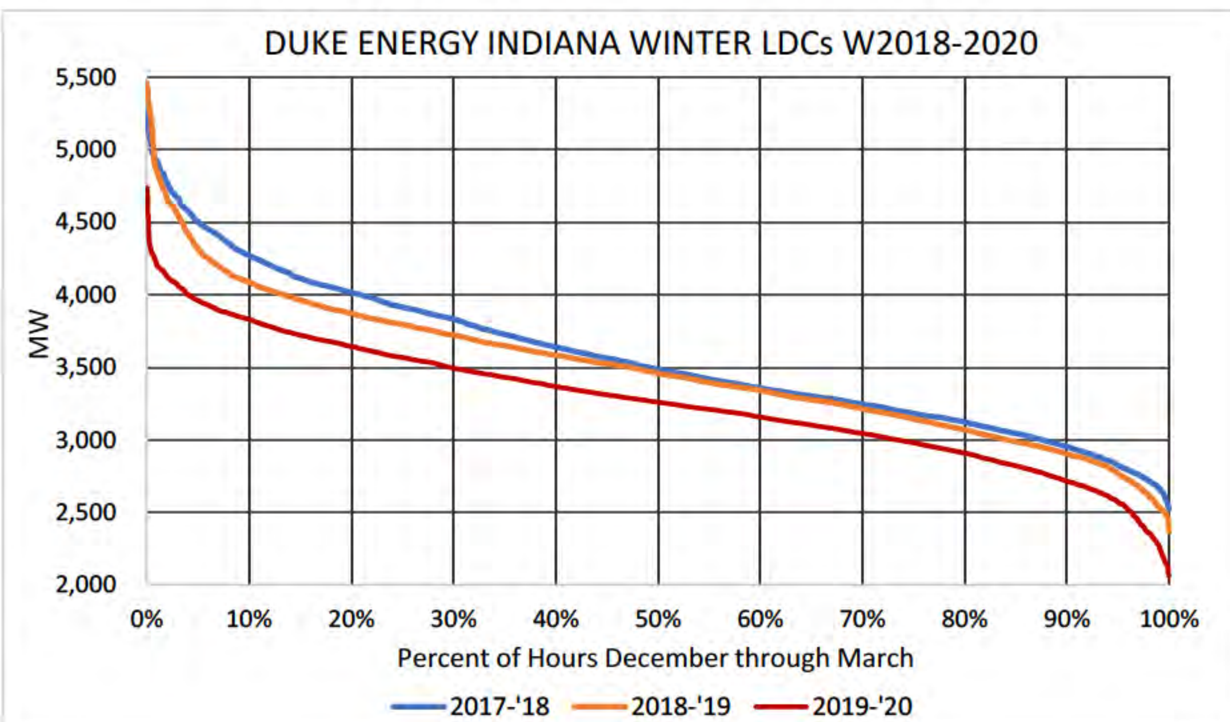
## 170 IAC 4-7-5 ENERGY AND DEMAND FORECASTS

### SEC. 5. (A) 1(A) ANNUAL LOAD DURATION CURVES

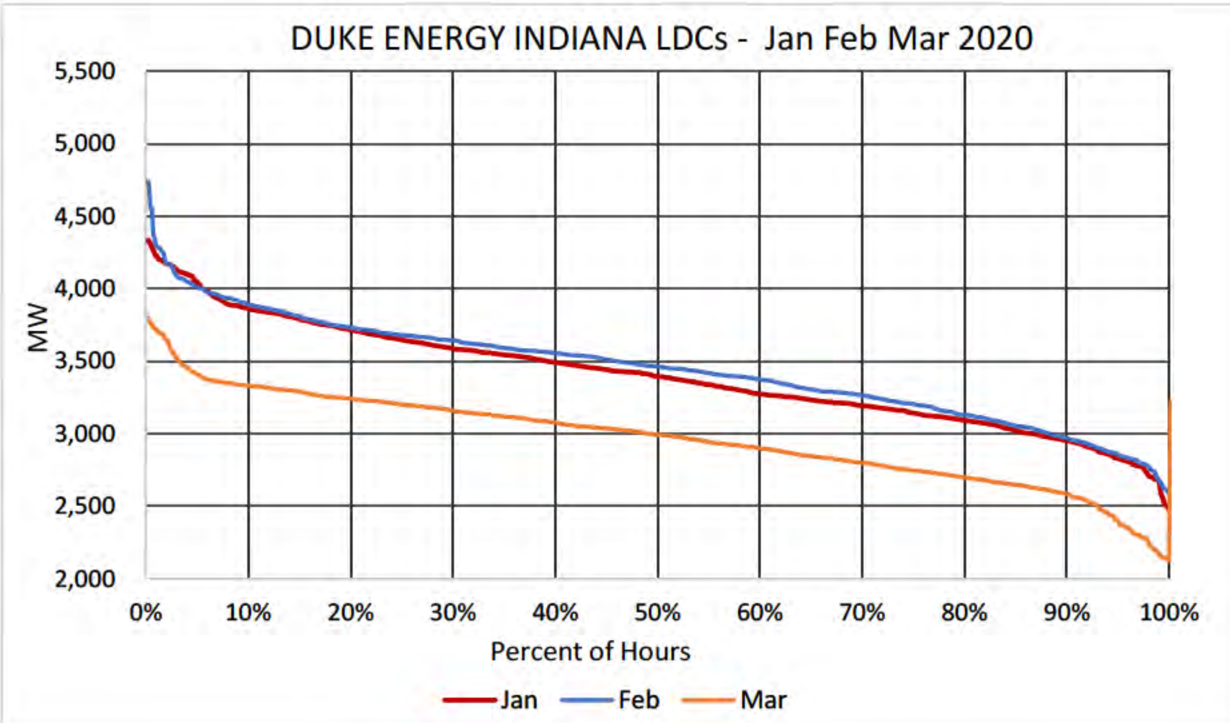


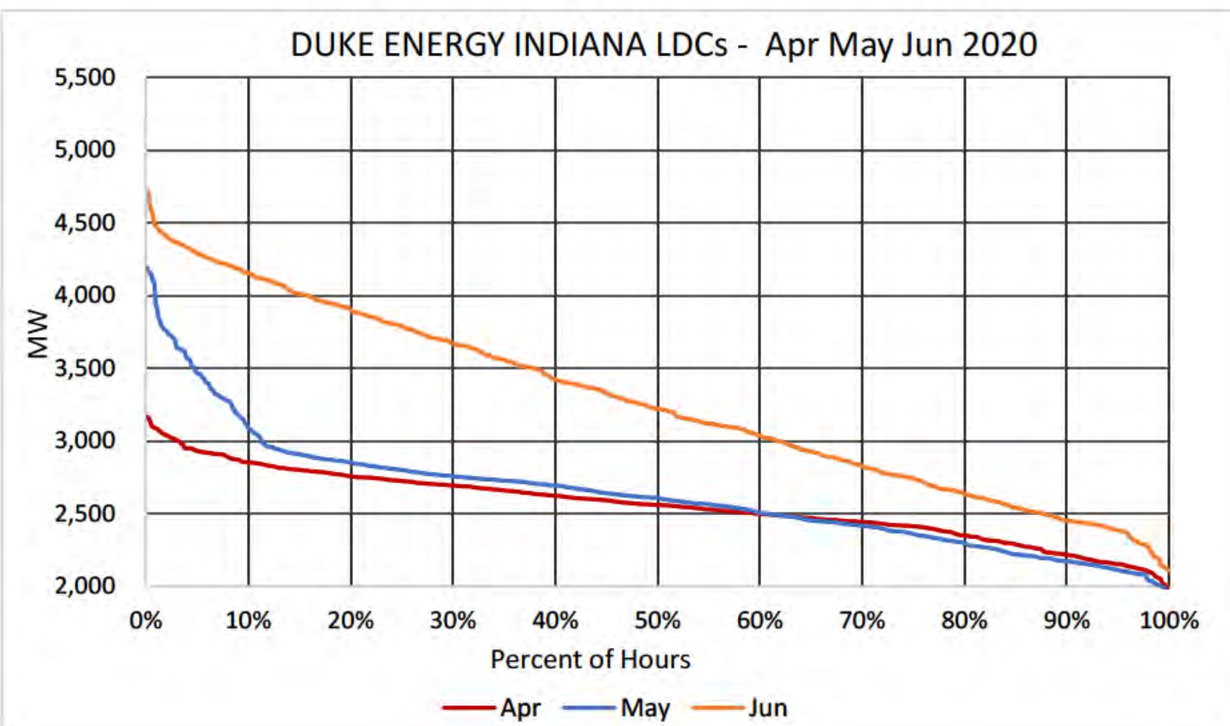
# SEC. 5. (A) 1(B) SEASONAL LOAD DURATION CURVES



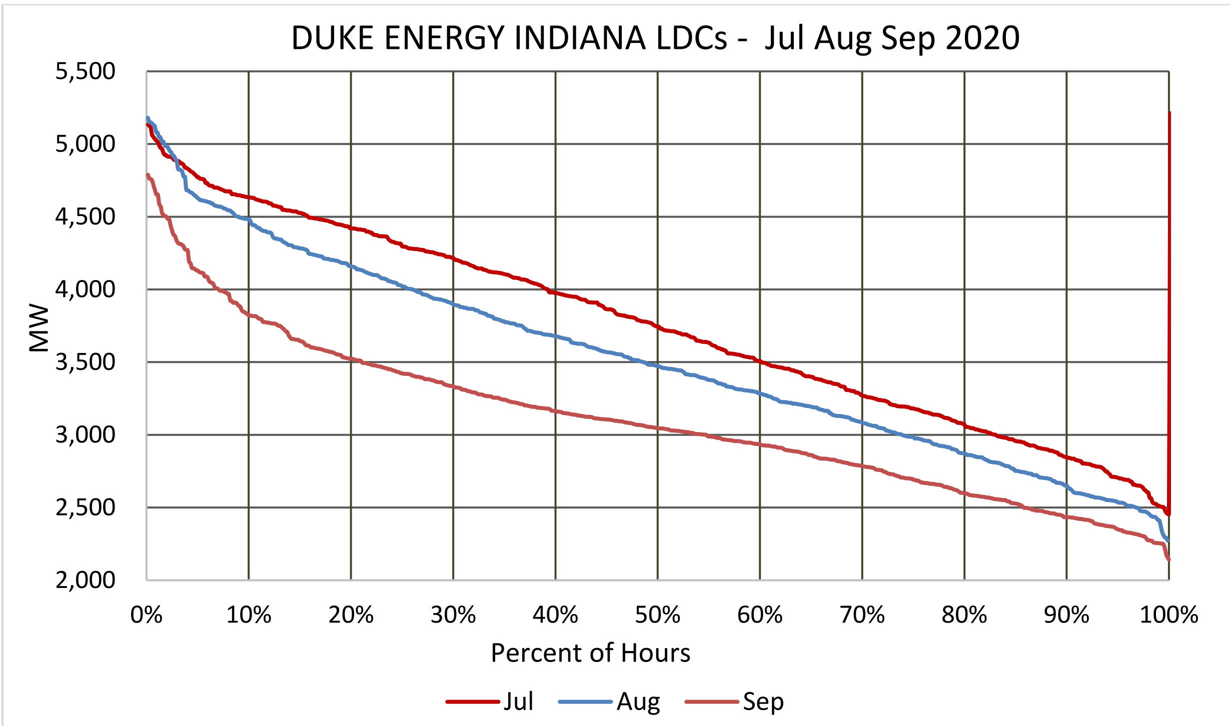



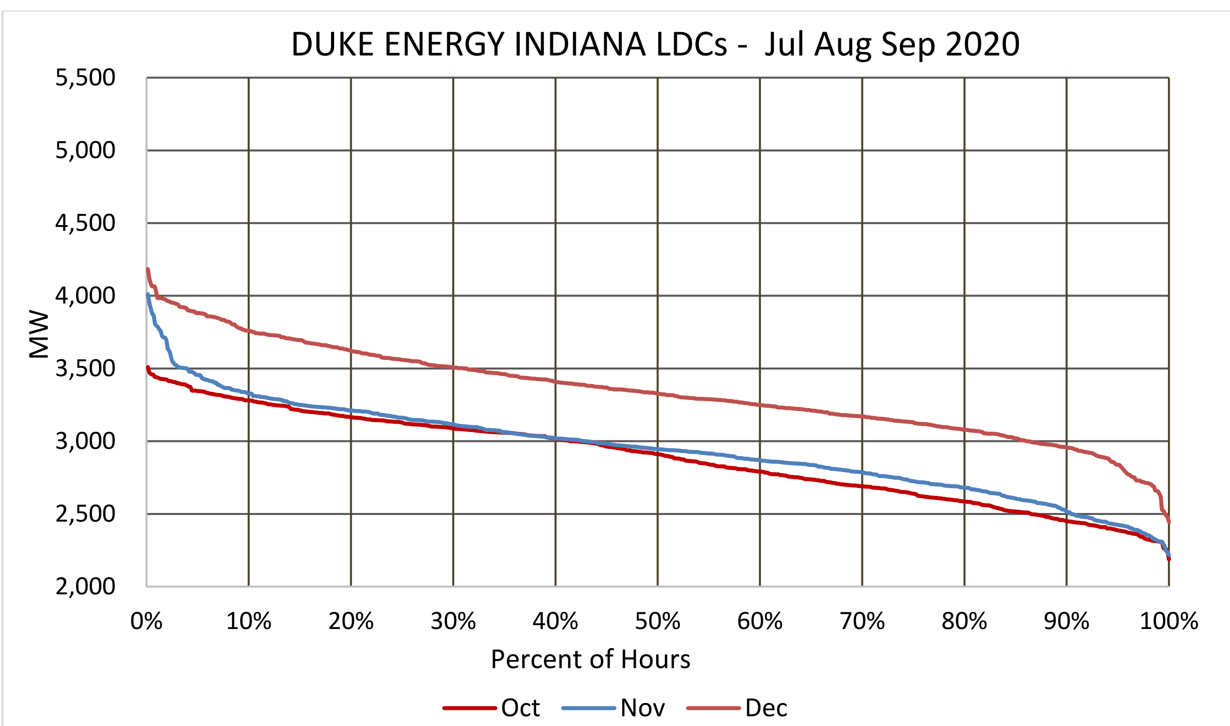
## SEC. 5. (A) 1(C) MONTHLY LOAD DURATION CURVES



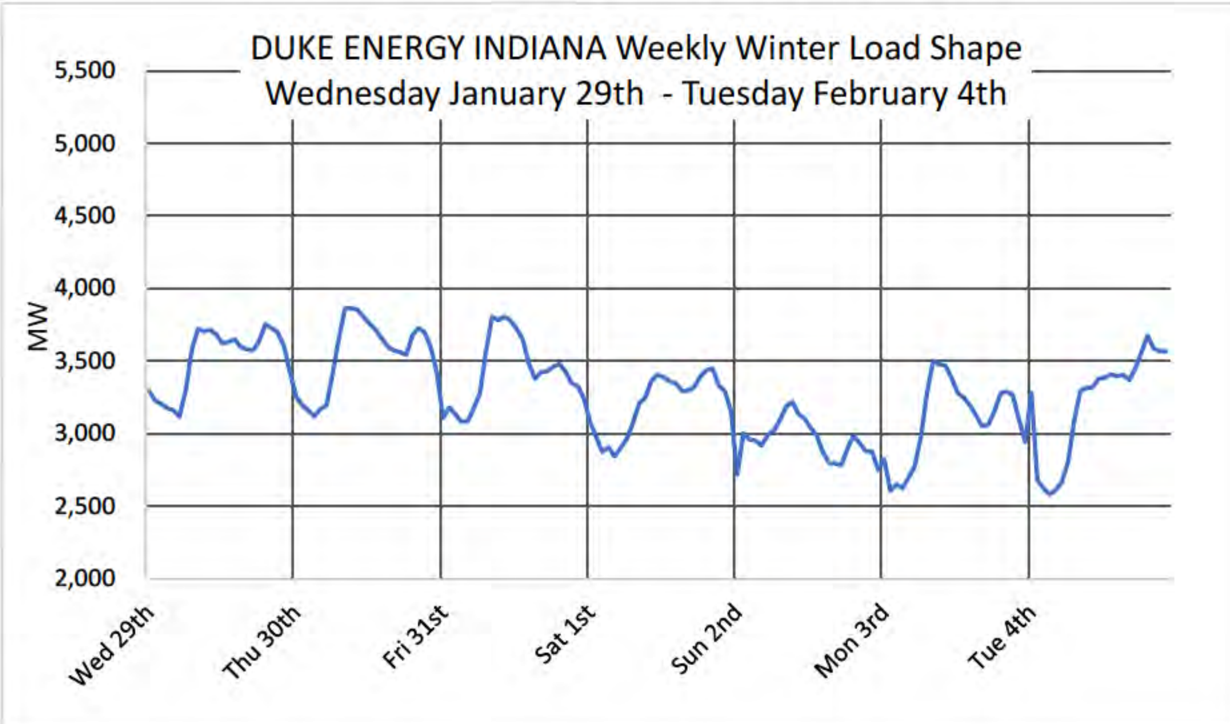



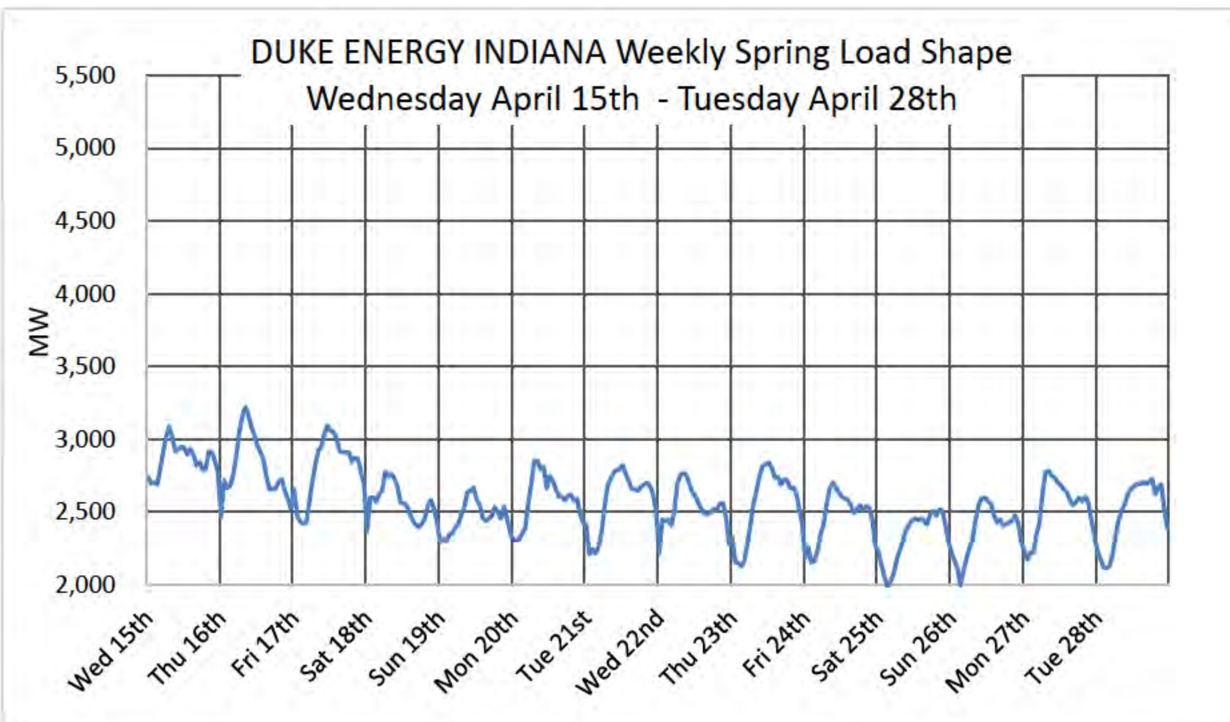
## SEC. 5.(A) 1(C) MONTHLY LOAD DURATION CURVES (CONT.)



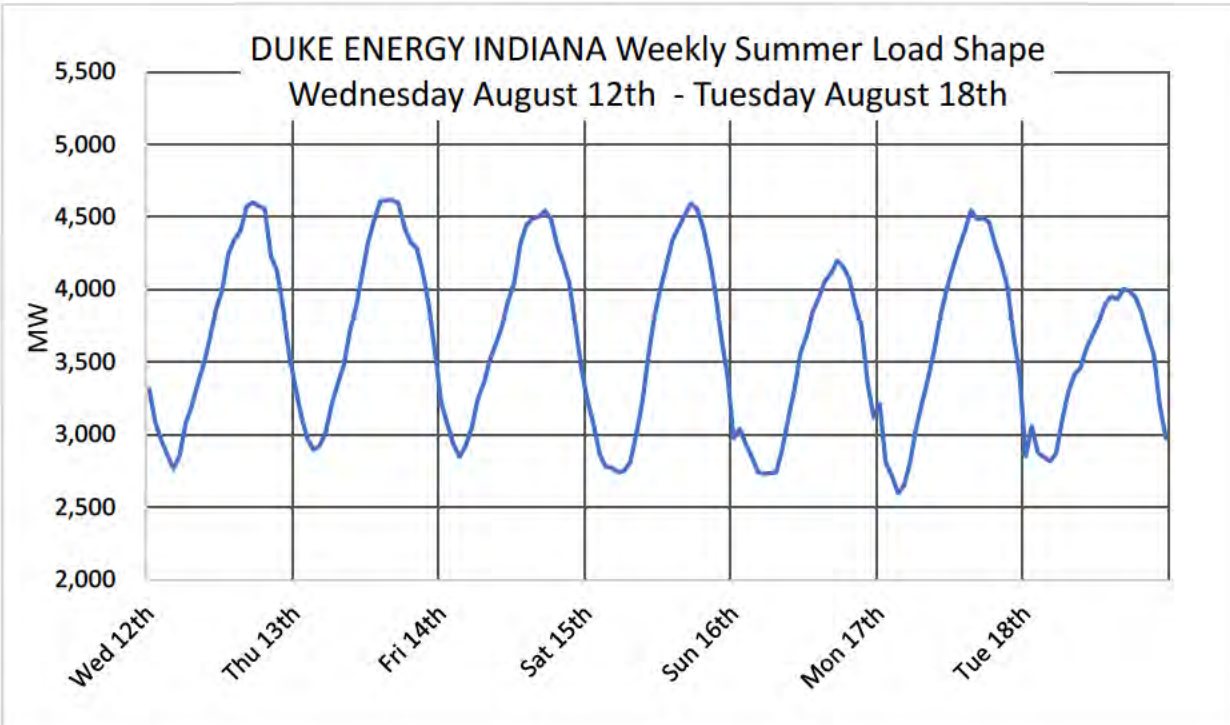



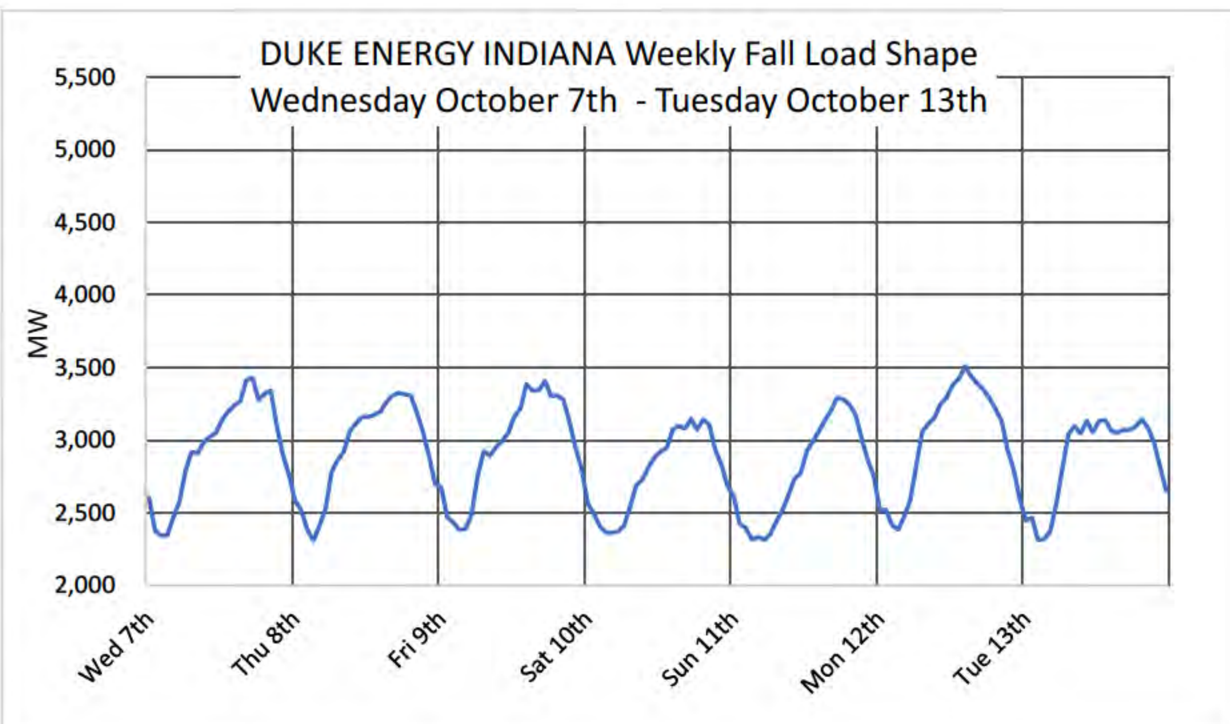
# SEC. 5. (A) 1(D) SELECTED WEEKLY LOAD SHAPES



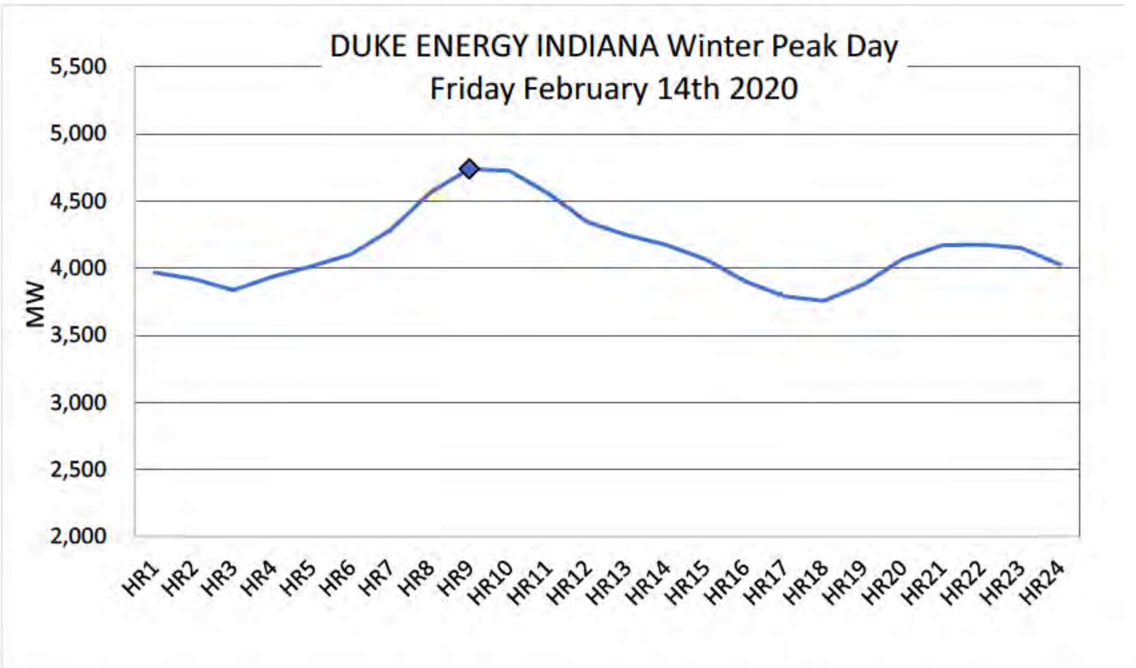



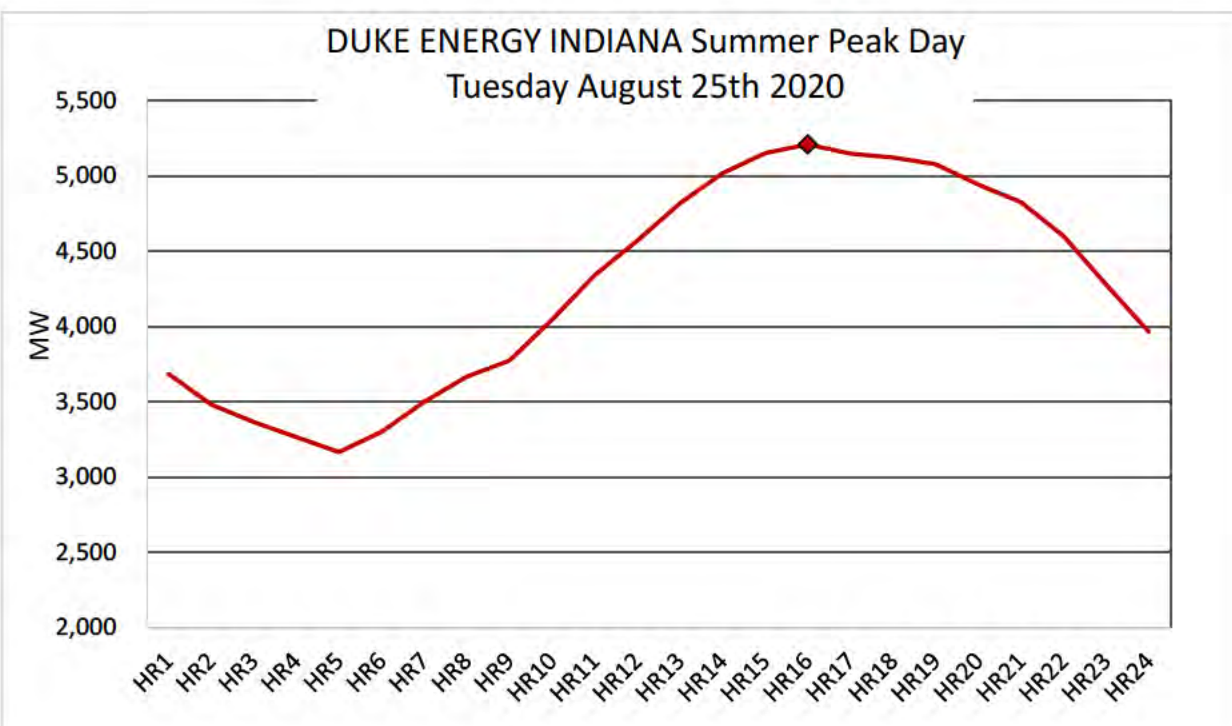
# SEC. 5.(A) 1(D) SELECTED WEEKLY LOAD SHAPES (CONT.)



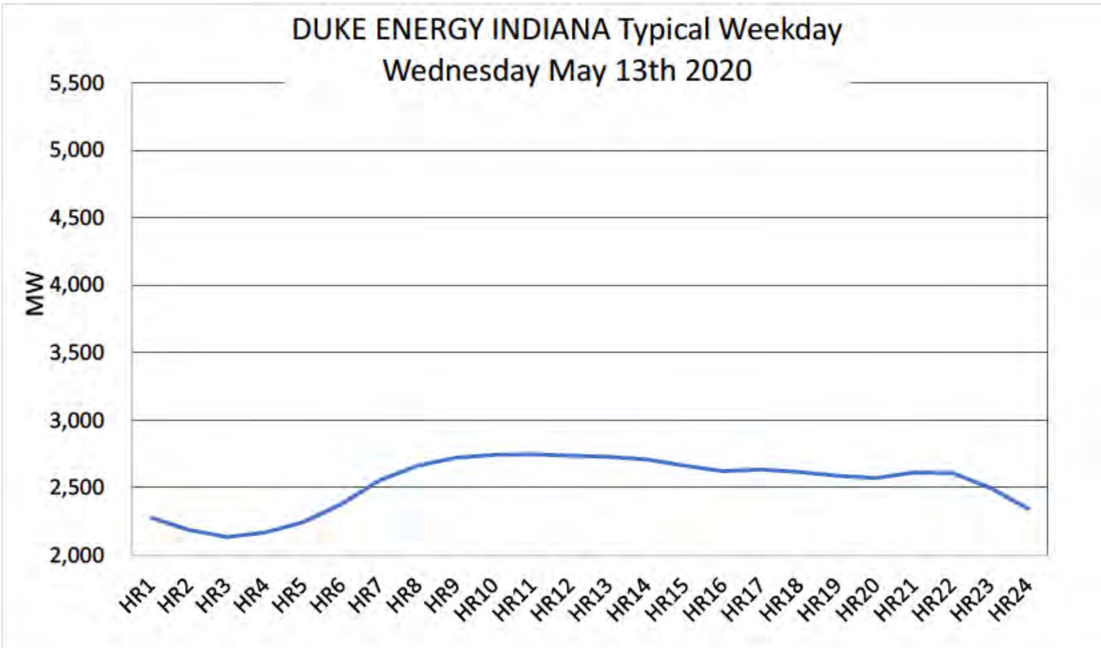



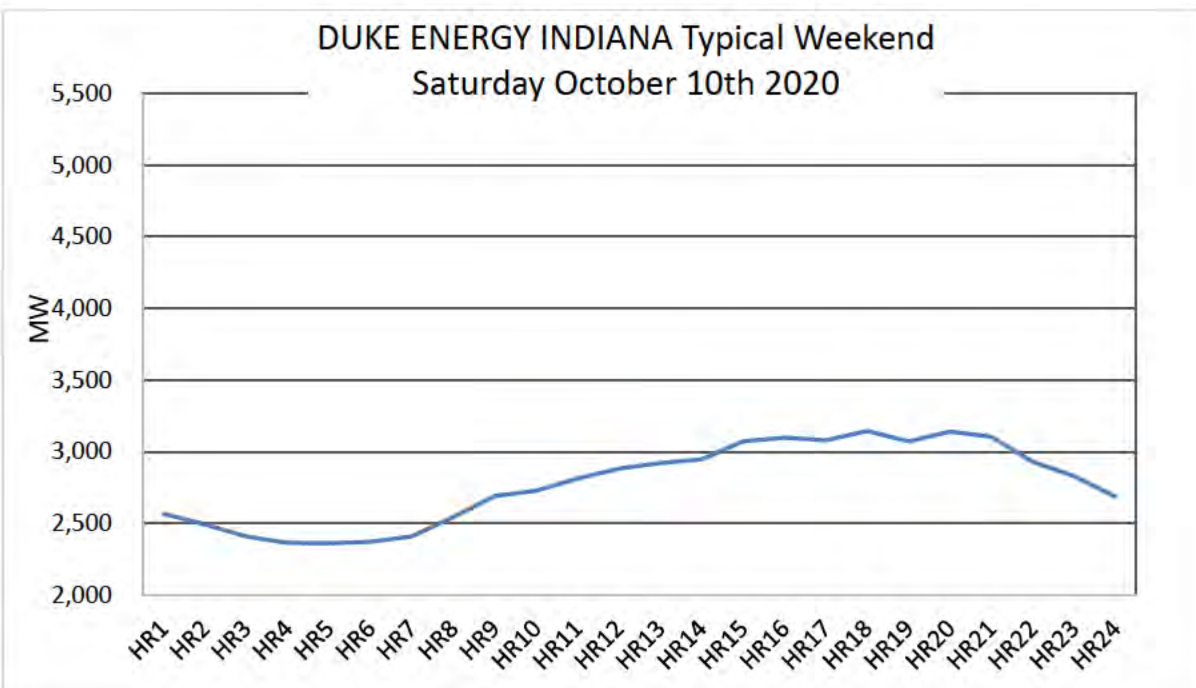
# SEC. 5. (A) 1(E) SELECTED DAILY LOAD SHAPES – WINTER PEAK DAY, SUMMER PEAK DAY



## SEC. 5. (A) 1(E) SELECTED DAILY LOAD SHAPES – TYPICAL WEEKDAY, TYPICAL WEEKEND (CONT.)



# SEC. 5. (A) 2(A) DISAGGREGATION OF HISTORICAL AND FORECAST ENERGY AND CUSTOMER DATA BY CUSTOMER CLASS

| Year | Residential | Commercial | Industrial | Other | Retail | Residential | Commercial | Industrial | Other | Retail |
|---|---|---|---|---|---|---|---|---|---|---|
| History | Gigawatt Hours | | | | | Customers | | | | |
| 2008 | 9,313 | 6,274 | 10,807 | 2,339 | 28,733 | 674,620 | 90,815 | 2,845 | 9,587 | 777,867 |
| 2009 | 8,884 | 6,007 | 9,029 | 2,312 | 26,232 | 674,103 | 90,842 | 2,815 | 9,863 | 777,623 |
| 2010 | 9,648 | 6,219 | 10,097 | 2,308 | 28,272 | 678,996 | 91,012 | 2,790 | 10,122 | 782,920 |
| 2011 | 9,182 | 6,135 | 10,167 | 2,247 | 27,731 | 680,389 | 90,892 | 2,754 | 10,302 | 784,336 |
| 2012 | 8,941 | 6,173 | 10,449 | 2,223 | 27,787 | 684,734 | 91,293 | 2,734 | 10,259 | 789,019 |
| 2013 | 9,232 | 6,203 | 10,449 | 2,224 | 28,109 | 689,735 | 91,446 | 2,726 | 10,282 | 794,188 |
| 2014 | 9,285 | 6,197 | 10,643 | 2,216 | 28,341 | 694,479 | 91,630 | 2,708 | 10,235 | 799,052 |
| 2015 | 8,924 | 6,245 | 10,505 | 2,147 | 27,821 | 700,953 | 91,956 | 2,707 | 10,220 | 805,835 |
| 2016 | 9,036 | 6,322 | 10,565 | 2,136 | 28,058 | 709,356 | 92,302 | 2,721 | 10,181 | 814,560 |
| 2017 | 8,645 | 6,146 | 10,599 | 2,107 | 27,496 | 715,639 | 92,682 | 2,718 | 10,145 | 821,184 |
| 2018 | 9,550 | 6,341 | 10,607 | 2,133 | 28,631 | 725,966 | 93,185 | 2,721 | 10,063 | 831,934 |
| 2019 | 9,247 | 6,208 | 10,327 | 2,056 | 27,837 | 735,652 | 93,424 | 2,692 | 10,056 | 841,823 |
| 2020 | 9,082 | 5,771 | 9,574 | 1,897 | 26,323 | 746,789 | 94,242 | 2,697 | 10,038 | 853,766 |
| Forecast | | | | | | | | | | |
| 2021 | 9,102 | 5,991 | 9,842 | 1,953 | 26,888 | 752,190 | 92,844 | 2,711 | 11,924 | 859,669 |
| 2022 | 9,115 | 6,064 | 10,155 | 2,030 | 27,364 | 762,525 | 93,255 | 2,699 | 11,964 | 870,442 |
| 2023 | 9,131 | 6,101 | 10,327 | 2,040 | 27,599 | 772,473 | 93,716 | 2,701 | 11,990 | 880,880 |
| 2024 | 9,234 | 6,137 | 10,375 | 2,039 | 27,785 | 782,170 | 94,152 | 2,702 | 12,015 | 891,040 |
| 2025 | 9,285 | 6,110 | 10,357 | 2,026 | 27,778 | 791,699 | 94,578 | 2,703 | 12,041 | 901,022 |
| 2026 | 9,383 | 6,117 | 10,390 | 2,011 | 27,902 | 800,967 | 94,993 | 2,704 | 12,067 | 910,732 |
| 2027 | 9,500 | 6,145 | 10,449 | 1,998 | 28,091 | 809,863 | 95,391 | 2,704 | 12,092 | 920,049 |
| 2028 | 9,645 | 6,188 | 10,467 | 1,985 | 28,285 | 818,507 | 95,777 | 2,705 | 12,115 | 929,104 |
| 2029 | 9,744 | 6,200 | 10,475 | 1,975 | 28,394 | 827,042 | 96,158 | 2,705 | 12,139 | 938,044 |
| 2030 | 9,865 | 6,217 | 10,503 | 1,965 | 28,550 | 835,489 | 96,534 | 2,705 | 12,162 | 946,891 |
| 2031 | 9,997 | 6,247 | 10,564 | 1,957 | 28,764 | 843,786 | 96,904 | 2,705 | 12,185 | 955,581 |
| 2032 | 10,163 | 6,300 | 10,622 | 1,947 | 29,032 | 851,903 | 97,265 | 2,705 | 12,208 | 964,081 |
| 2033 | 10,288 | 6,307 | 10,669 | 1,937 | 29,201 | 859,788 | 97,616 | 2,705 | 12,228 | 972,337 |
| 2034 | 10,449 | 6,333 | 10,710 | 1,930 | 29,422 | 867,400 | 97,954 | 2,705 | 12,248 | 980,308 |
| 2035 | 10,619 | 6,375 | 10,756 | 1,929 | 29,679 | 874,973 | 98,291 | 2,705 | 12,268 | 988,236 |
| 2036 | 10,826 | 6,454 | 10,812 | 1,935 | 30,028 | 882,463 | 98,623 | 2,705 | 12,287 | 996,079 |
| 2037 | 10,979 | 6,508 | 10,872 | 1,946 | 30,305 | 889,728 | 98,945 | 2,706 | 12,305 | 1,003,684 |
| 2038 | 11,150 | 6,594 | 10,939 | 1,960 | 30,643 | 896,778 | 99,257 | 2,706 | 12,322 | 1,011,064 |
| 2039 | 11,320 | 6,697 | 11,018 | 1,979 | 31,013 | 903,723 | 99,565 | 2,706 | 12,339 | 1,018,332 |
| 2040 | 11,510 | 6,805 | 11,095 | 1,997 | 31,407 | 910,077 | 99,840 | 2,706 | 12,355 | 1,024,978 |
| 2041 | 11,637 | 6,864 | 11,155 | 2,008 | 31,663 | 915,832 | 100,082 | 2,706 | 12,370 | 1,030,991 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Δ | 2,555 | 1,093 | 1,581 | 111 | 5,340 | 169,043 | 5,841 | 9 | 2,332 | 177,225 |
| CAGR '20-'41 | 1.2% | 0.8% | 0.7% | 0.3% | 0.9% | 1.0% | 0.3% | 0 0% | 1.0% | 0.9% |

## SEC. 5. (A) (3) ACTUAL AND WEATHER NORMALIZED ENERGY AND DEMAND

| 2021 IRP | | | | |
|---|---|---|---|---|
| Year | Energy Actual GWh | Energy W/Normal GWh | Summer Actual MW | Summer W/Normal MW |
| History: | | | | |
| 2011 | 33,625 | 33,749 | 6,749 | 6,490 |
| 2012 | 31,028 | 31,369 | 6,494 | 6,510 |
| 2013 | 33,104 | 34,106 | 6,229 | 6,461 |
| 2014 | 32,063 | 31,728 | 5,830 | 6,084 |
| 2015 | 32,131 | 32,003 | 5,863 | 6,008 |
| 2016 | 32,318 | 32,267 | 6,079 | 6,181 |
| 2017 | 32,097 | 32,039 | 5,838 | 6,049 |
| 2018 | 31,532 | 31,547 | 5,904 | 5,895 |
| 2019 | 32,191 | 31,964 | 5,896 | 5,686 |
| 2020 | 31,447 | 31,678 | 5,755 | 6,029 |

## SEC 5(A)(4) A DISCUSSION OF METHODS AND PROCESSES USED TO WEATHER NORMALIZE

Duke Energy Indiana weather normalizes weather sensitive energy sales and peak demands to an average 30-year condition using the Indianapolis Airport weather station. This normal weather series is updated every year by adding the latest complete new year and dropping the earliest complete year.

The Duke Energy Indiana weather normalization of energy sales applies a daily modeling procedure that incorporates daily Duke Energy Indiana load research data by class. This procedure, which is also the basis for class load profiles, selects weather variables that best explains historical weather variation. Day-of-week variables capture non-weather variation as well. Each model's weather variable coefficient is multiplied by the difference between actual and normal series and summed by month to determine the weather adjustment. The difference between actual and normal weather conditions is multiplied by the specific weather variable's model coefficient. This results in a weather adjustment to energy.

The Duke Energy Indiana weather normalization of peak demand is very similar, but the weather in question deals with the weather on each monthly peak day. Normal monthly peak weather is a 30-year average of peak weather. For Summer and Winter peak, typically January and July, a 30-year seasonal extreme is developed to account for the monthly variability of the seasonal peak. Again, the difference between actual weather and normal projected weather is applied to a peak model weather coefficient.

## SEC 5(A)(5) A TWENTY (20) YEAR PERIOD FOR PEAK DEMAND AND ENERGY USAGE FORECAST

| Year | System Annual mW | Retail Annual mW | Wholesale Annual mW | System Annual gWh | Retail Annual gWh | Wholesale Annual gWh | System Load Factor |
|---|---|---|---|---|---|---|---|
| 2021 | 5,702 | 5,255 | 442 | 31,765 | 29,047 | 2,684 | 63.6% |
| 2022 | 5,804 | 5,317 | 483 | 32,124 | 29,561 | 2,530 | 63.2% |
| 2023 | 6,115 | 5,362 | 749 | 32,875 | 29,814 | 3,027 | 61.4% |
| 2024 | 6,025 | 5,375 | 647 | 32,939 | 30,015 | 2,890 | 62.4% |
| 2025 | 6,018 | 5,368 | 647 | 32,951 | 30,008 | 2,910 | 62.5% |
| 2026 | 5,932 | 5,389 | 539 | 32,542 | 30,141 | 2,367 | 62.6% |
| 2027 | 5,928 | 5,416 | 509 | 32,714 | 30,346 | 2,335 | 63.0% |
| 2028 | 5,697 | 5,440 | 254 | 32,457 | 30,555 | 1,868 | 65.0% |
| 2029 | 5,710 | 5,453 | 254 | 32,151 | 30,673 | 1,444 | 64.3% |
| 2030 | 5,730 | 5,472 | 254 | 32,320 | 30,842 | 1,444 | 64.4% |
| 2031 | 5,763 | 5,505 | 254 | 32,551 | 31,073 | 1,444 | 64.5% |
| 2032 | 5,804 | 5,547 | 254 | 32,845 | 31,363 | 1,448 | 64.6% |
| 2033 | 5,833 | 5,575 | 254 | 33,023 | 31,545 | 1,444 | 64.6% |
| 2034 | 5,867 | 5,610 | 254 | 33,262 | 31,783 | 1,444 | 64.7% |
| 2035 | 5,912 | 5,654 | 254 | 33,539 | 32,061 | 1,444 | 64.8% |
| 2036 | 5,972 | 5,715 | 254 | 33,920 | 32,438 | 1,448 | 64.8% |
| 2037 | 6,030 | 5,772 | 254 | 34,215 | 32,737 | 1,444 | 64.8% |
| 2038 | 6,094 | 5,837 | 254 | 34,580 | 33,102 | 1,444 | 64.8% |
| 2039 | 6,168 | 5,910 | 254 | 34,980 | 33,502 | 1,444 | 64.7% |
| 2040 | 6,241 | 5,984 | 254 | 35,410 | 33,928 | 1,448 | 64.8% |
| 2041 | 6,295 | 6,038 | 254 | 35,683 | 34,205 | 1,444 | 64.7% |

## SEC 5(A)(6-9) AN EVALUATION OF THE PERFORMANCE OF PEAK DEMAND AND ENERGY USAGE FOR THE PREVIOUS TEN (10) YEARS

The performance of peak demand and energy usage during the past ten years has been underwhelming. The intense impact of Covid-19 on electric consumption sits on the foundation of the Great Recession, the most severe economic recession in the United States since the 1930s. This has left the utility industry in a period of great uncertainty, akin to the period following the Oil embargoes in the 1970s. According to the EIA, “It will take a while for the energy sector to get to its new ‘normal,’ the pandemic triggered a historic energy demand shock that led to… decreases in energy production, and sometimes volatile commodity prices in 2020. The pace of economic recovery, advances in technology, changes in trade flows, and energy incentives will determine how the United States produces and consumes energy in the future.”

{*https://www.eia.gov/todayinenergy/detail.php?id=46636*}. Duke Energy Indiana actual load nor peak demand have returned to the level set in 2008. The destruction of wealth and jobs from the Great Recession set utility growth rates in customer growth and energy usage back drastically. When it appeared that some growth might be returning, Covid-19 hit and almost completely shut down the economy, an event the economy in general, and specifically electric utility sales are slowly recovering from.

A second industry event occurring over the last ten years that must be mentioned is the availability of merchant generation. Relatively inexpensive natural gas (central station or customer self-service) generation and subsidized renewable generation has resulted in low-cost generation options for wholesale service municipals and cooperatives. Duke Energy Indiana has gone through a material drop in wholesale sales in recent years; we expect the summit of our wholesale to hit in 2023 peak, and then drop nearly 500 MW over the course of the forecast.

A third factor impacting the level of growth in Duke Energy Indiana peak and energy sales is the adoption of federally mandated highly efficient residential and commercial sector appliances and utility sponsored programs offered to help spur more efficient use of electricity. Duke Energy Indiana has observed that the residential and commercial classes are more likely to participate in utility energy efficiency programs with the current legislative landscape in Indiana for large industrial customers enabled to opt-out of EE programs. Industrial customers are able to implement their own cost saving efforts, including a growing number of combined heat and power (CHP) units.

Each of these events have worked to reduce electric energy sales growth and even shrink the average annual kWh use per residential customer for several years. We have found that, currently, Itron's SAE (Statistically Adjusted End-use) forecast methodology works best to capture the changing levels of more efficient appliances saturating through the residential households and commercial class end-uses.

While Duke Energy Indiana has been projecting impacts of roof-top solar and electric vehicles upon the energy and peak demand projections for several years, we are continually improving these projections by applying actual solar load shapes and EV "charging time" data to improve our understanding of these influences upon class hourly load shapes.

## LOAD MODIFIERS - ROOFTOP SOLAR AND ELECTRIC VEHICLES

Rooftop solar photovoltaic (PV) and electric vehicles (EVs) are considered load modifiers for the load forecast: behind-the-meter solar PV generation reduces the effective load that Duke Energy serves while plug-in EV charging increases the load that Duke Energy serves. Rooftop solar PV generation and EV load are independently forecasted and combined with the base load and EE impacts to produce the final electric load forecast. Because the impacts from existing rooftop solar PV generation and EVs are embedded in the historical data from which the base load forecast is derived, only incremental or “net new” rooftop solar PV generation and EV load are added within the planning horizon.

## ROOFTOP SOLAR

Rooftop solar refers to behind-the-meter solar PV generation for residential, commercial, and industrial customers. Energy produced by rooftop solar is consumed by the customer and offsets their electric load consumption. Excess energy is exported to the grid and credited to the customer at rates specific to the net energy metering (NEM) policies in Indiana. As of the IRP filing, the current NEM rates are full retail rates, but are expected to decrease to 125% of the marginal electricity price for an excess generation starting July 1, 2022. Despite this decrease in NEM rates and the corresponding increase in the payback period, forecasted rooftop solar adoptions are expected to increase over the planning horizon due to declining technology costs and an increase in customer preference for self-generation.

The rooftop solar generation forecast is created from the capacity forecasts and hourly production profiles for residential, commercial, and industrial customers.  The capacity forecast is developed as the product of a customer adoption forecast and an average capacity value. The customer adoption forecast is based on linear regression modeling in Itron MetrixND and relies on current adoption rates and both current and future payback periods (amount of time to recover the cost of installing rooftop solar) to generate a customer adoption forecast. Payback periods are a function of installation costs, regulatory incentives, and electric bill savings. Historical and projected technology costs are provided by Guidehouse Inc. while projected incentives and bill savings are developed internally based on current regulatory policies and input from subject matter experts. The average capacity value, or size of the installed rooftop PV system, is derived using historical adoption trends and is shown in Table B-1 below.

## TABLE B-1
## AVERAGE ROOFTOP SOLAR CAPACITY (KW-AC)

| Customer Class | Duke Energy Indiana |
|---|---|
| Residential | 8 |
| Non-residential | 250 |

Hourly production profiles are developed using 20 years of historical irradiance data from Solar Anywhere and Solcast for 5 locations across Duke Energy Indiana's service territory. This data is modeled in PVsyst to develop capacity factors for all sites and years, which are combined on weighted average basis to produce '12x24' hourly production profiles (there is one 24-hour generation profile for each month).

The table below shows the overall increase in rooftop solar customers, capacity, and energy increases from the beginning to the end of the IRP planning period.

## TABLE B-2
## NET NEW ROOFTOP SOLAR ADOPTIONS FROM 2021

| Year | Number of Customers | Percent of Total Customers | Capacity (MW) | Energy (MWH/YEAR) |
|---|---|---|---|---|
| 2021 | 470 | 0.3% | 10 | 5,700 |
| 2035 | 6,400 | 0.8% | 143 | 184,700 |

## ELECTRIC VEHICLES

EV charging represents a significant opportunity for load growth in the planning horizon. President Biden's recently announced goal of having 50% of new U.S. EV sales be electric by 2030 and announcements by various automakers to achieve new U.S. EV sales of 40%-50% by 2030 are indicators that EV adoption will continue to expand. New vehicle sales are only a portion of the vehicles in operation, but the load growth from the infrastructure needed to provide for electric vehicles charging presents a significant opportunity over the planning horizon.

Duke Energy's EV load forecast is derived from a series of EV forecasts and load profiles. The Electric Power Research Institute (EPRI) provides EV forecasts specific to Duke Energy Indiana's service area for three adoption cases (low, medium, and high) and five vehicle types. In recent years, Duke Energy has used EPRI's medium adoption case with minor adjustments as needed for known or expected changes in the market. Vehicle types include plug-in EVs with 10-, 20- and 40-mile range and fully electric vehicles with 100 and 250-mile range. Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential and public charging.

The EPRI vehicle load forecast and the unique hourly load profiles are used to develop jurisdictional hourly level load profiles that is used as an input to feed the Duke Energy Indiana load forecast.

Table B-3 shows the projected incremental additions of EVs in operation, along with the impacts on energy, at the beginning and end of the planning horizon.

## TABLE B-3
## ELECTRIC VEHICLES IN OPERATION AND LOAD IMPACTS

| YEAR | EVS IN OPERATION | PERCENT OF VEHICLE FLEET | LOAD (MWH/YEAR) |
|---|---|---|---|
| 2021 | 5,906 | 0.4% | 19,500 |
| 2035 | 191,708 | 10.6% | 720,000 |

## SEC 5(B)(1-3) AN EVALUATION OF PLAUSIBLE RISK BOUNDARIES OR ALTERNATIVE FORECASTS OF PEAK DEMAND AND ENERGY USE

A High and a Low scenario were prepared centered on the Base (Most Likely) scenario. The Base Scenario utilized Moody's January 2021 edition of their Baseline Forecast (the probability that the economy will perform either better or worse is 50%). The Key Assumptions of the Baseline Forecast:


- **55.5 Million Covid-19 Cases - Herd immunity achieved by September.**
- **Federal Government will approve $1.9 trillion in additional fiscal support.**
- **Federal Reserve keeps the federal funds rate at 0% to 0.25%, until the 2nd Q 2023. The Federal Reserve does not taper its asset purchases until 2022.**
- **U.S. trade-weighted dollar remains strong while West Texas Intermediate crude oil prices remain low, hovering between $40 and $60 per barrel through the end of 2022.**

As previously stated, Duke Energy Indiana utilizes a SAE model, where the projected efficiencies and saturations of appliance types impact the forecast more than the economics alone, which are indexed. Indexing the economic variables decreases response to changes in level of the dependent variable. In addition, the low levels of sales growth over the last decade decreased the dynamism of response to the relatively mild economic variation provided in alternative scenarios provided by Moody's in the economic variables utilized in the base case. The initial runs with the alternate economic scenarios did not provide sufficient variation from the base model to utilize in resource adequacy modeling. Therefore, the high and low case where developed utilizing 90/10 Confidence levels established using 1.645 standard deviations of the mean of the forecast to establish an upper and lower band. We added a high case (to meet the current administration's 2030 goal of a 50% adoption rate) of Electric Vehicle adoption.

These High and Low forecasts are concordant with Moody's S1 and S3 scenarios, respectively. The High Scenario or S1-Upside-10th Percentile (a 10% probability that the economy will perform better and 90% probability that it will perform worse.) The Key Assumptions of the S1 Forecast:

- Consumer optimism increases supported by development of a reliable vaccine for Covid-19.
- Businesses reopen at a somewhat faster pace than in the baseline as new Covid-19 cases recede relatively quickly.
- The expected fiscal stimulus boosts the economy more than expected.
- Consumers return to spending on air travel, retail and hotels sooner than expected.
- Steadily declining unemployment and consequently fewer business bankruptcies.
- Political and economic tensions between the U.S. and China decline.
- US Adopts electric vehicles as outlined in Administration plan (Duke Energy Indiana addition).

The Low Scenario or S3-Downside-90th Percentile (a 90% probability that the economy will perform better and 10% probability that it will perform worse.) The Key Assumptions of the S3 Forecast:

- Incidence of new infections, hospitalizations, and deaths from Covid-19 is significantly above the baseline, causing businesses to reopen much more slowly than expected. State and local officials in some areas of the country require some nonessential businesses to close, but there is no return to widespread shutdowns.
- Concern about vaccine efficacy, effectiveness of widespread distribution, and agreement on the part of enough people to receive it.
- Consumer confidence erodes in the first quarter of 2021, spending on air travel, retail and hotels is weaker than expected, and the
- Economy falls back into recession.
- Disagreements in Congress prevent additional federal fiscal stimulus measures.
- Political and economic tensions with China begin to rise again amid the disappointing outcomes regarding the incidence of illness and the economy.

The publishing address for Moody's Analytics is 121 North Walnut Street, West Chester, PA 19380.

# SEC 5 (B)(1-3) LOW – BASE- HIGH ENERGY & PEAK SCENARIOS

| | Annual System Requirements GWH | | | | |
|---|---|---|---|---|---|
| Year | Low | | Base | | High |
| 2021 | 31,452 | *-1.0%* | 31,765 | *1.0%* | 32,078 |
| 2022 | 31,812 | *-1.0%* | 32,124 | *1.0%* | 32,437 |
| 2023 | 32,562 | *-1.0%* | 32,875 | *1.0%* | 33,190 |
| 2024 | 32,626 | *-0.9%* | 32,939 | *1.0%* | 33,265 |
| 2025 | 32,638 | *-0.9%* | 32,951 | *1.0%* | 33,294 |
| 2026 | 32,229 | *-1.0%* | 32,542 | *1.1%* | 32,910 |
| 2027 | 32,402 | *-1.0%* | 32,714 | *1.2%* | 33,117 |
| 2028 | 32,144 | *-1.0%* | 32,457 | *1.5%* | 32,935 |
| 2029 | 31,838 | *-1.0%* | 32,151 | *1.8%* | 32,733 |
| 2030 | 32,007 | *-1.0%* | 32,320 | *2.2%* | 33,044 |
| 2031 | 32,238 | *-1.0%* | 32,551 | *2.5%* | 33,362 |
| 2032 | 32,532 | *-1.0%* | 32,845 | *2.8%* | 33,759 |
| 2033 | 32,711 | *-0.9%* | 33,023 | *3.1%* | 34,049 |
| 2034 | 32,949 | *-0.9%* | 33,262 | *3.5%* | 34,417 |
| 2035 | 33,226 | *-0.9%* | 33,539 | *3.9%* | 34,836 |
| 2036 | 33,607 | *-0.9%* | 33,920 | *4.3%* | 35,372 |
| 2037 | 33,903 | *-0.9%* | 34,215 | *4.7%* | 35,825 |
| 2038 | 34,267 | *-0.9%* | 34,580 | *5.1%* | 36,359 |
| 2039 | 34,667 | *-0.9%* | 34,980 | *5.6%* | 36,939 |
| 2040 | 35,097 | *-0.9%* | 35,410 | *6.1%* | 37,566 |
| 2041 | 35,370 | *-0.9%* | 35,683 | *6.8%* | 38,121 |
| CAGR | | | | | |
| 2021-'41 | 0.6% | | 0.6% | | 0.9% |

| | Annual System Requirements MWH | | | | |
|---|---|---|---|---|---|
| Year | Low | | Base | | High |
| 2021 | 5,663 | *-0.7%* | 5,702 | *1.2%* | 5,770 |
| 2022 | 5,788 | *-0.3%* | 5,804 | *1.6%* | 5,896 |
| 2023 | 6,122 | *0.1%* | 6,115 | *1.9%* | 6,232 |
| 2024 | 6,056 | *0.5%* | 6,025 | *2.3%* | 6,167 |
| 2025 | 6,054 | *0.6%* | 6,018 | *3.1%* | 6,204 |
| 2026 | 5,970 | *0.6%* | 5,932 | *3.8%* | 6,160 |
| 2027 | 5,971 | *0.7%* | 5,928 | *4.6%* | 6,201 |
| 2028 | 5,743 | *0.8%* | 5,697 | *5.6%* | 6,015 |
| 2029 | 5,742 | *0.6%* | 5,710 | *6.8%* | 6,098 |
| 2030 | 5,763 | *0.6%* | 5,730 | *7.8%* | 6,178 |
| 2031 | 5,793 | *0.5%* | 5,763 | *8.6%* | 6,259 |
| 2032 | 5,830 | *0.4%* | 5,804 | *9.4%* | 6,349 |
| 2033 | 5,850 | *0.3%* | 5,833 | *10.2%* | 6,426 |
| 2034 | 5,875 | *0.1%* | 5,867 | *10.9%* | 6,509 |
| 2035 | 5,904 | *-0.1%* | 5,912 | *11.6%* | 6,600 |
| 2036 | 5,944 | *-0.5%* | 5,972 | *12.3%* | 6,704 |
| 2037 | 5,976 | *-0.9%* | 6,030 | *12.8%* | 6,803 |
| 2038 | 6,017 | *-1.3%* | 6,094 | *13.4%* | 6,913 |
| 2039 | 6,063 | *-1.7%* | 6,168 | *14.0%* | 7,031 |
| 2040 | 6,098 | *-2.3%* | 6,241 | *15.0%* | 7,176 |
| 2041 | 6,126 | *-2.7%* | 6,295 | *15.6%* | 7,280 |
| CAGR | | | | | |
| 2021-'41 | 0.4% | | 0.5% | | 1.2% |

## SEC 5 (C) ELECTRIC VEHICLE, SOLAR& UTILITY ENERGY EFFICIENCY IMPACT ON RETAIL SALES

| | | | Gigawatt Hours | | |
|---|---|---|---|---|---|
| Year | "Baseline" | EV | PV | UEE | Total |
| 2021 | 27.0 | 0.0 | (0.0) | (0.1) | 26.9 |
| 2022 | 27.6 | 0.0 | (0.0) | (0.2) | 27.4 |
| 2023 | 27.9 | 0.0 | (0.0) | (0.3) | 27.6 |
| 2024 | 28.2 | 0.0 | (0.1) | (0.4) | 27.8 |
| 2025 | 28.4 | 0.1 | (0.1) | (0.6) | 27.8 |
| 2026 | 28.6 | 0.1 | (0.1) | (0.7) | 27.9 |
| 2027 | 28.9 | 0.1 | (0.1) | (0.8) | 28.1 |
| 2028 | 29.2 | 0.2 | (0.1) | (0.9) | 28.3 |
| 2029 | 29.3 | 0.2 | (0.1) | (1.0) | 28.4 |
| 2030 | 29.5 | 0.3 | (0.1) | (1.1) | 28.6 |
| 2031 | 29.8 | 0.3 | (0.1) | (1.2) | 28.8 |
| 2032 | 30.1 | 0.4 | (0.2) | (1.3) | 29.0 |
| 2033 | 30.2 | 0.5 | (0.2) | (1.4) | 29.2 |
| 2034 | 30.4 | 0.6 | (0.2) | (1.4) | 29.4 |
| 2035 | 30.6 | 0.7 | (0.2) | (1.4) | 29.7 |
| 2036 | 30.8 | 0.8 | (0.2) | (1.4) | 30.0 |
| 2037 | 31.0 | 0.9 | (0.2) | (1.4) | 30.3 |
| 2038 | 31.2 | 1.0 | (0.2) | (1.3) | 30.6 |
| 2039 | 31.4 | 1.1 | (0.3) | (1.3) | 31.0 |
| 2040 | 31.7 | 1.3 | (0.3) | (1.3) | 31.4 |
| 2041 | 31.8 | 1.4 | (0.3) | (1.2) | 31.7 |
| Total Δ | 4.9 | 1.4 | (0.3) | (1.2) | 4.8 |


DUKE ENERGY
INDIANA

# APPENDIX C

## SUPPLY-SIDE RESOURCES

APPENDIX C

# SUPPLY-SIDE RESOURCES

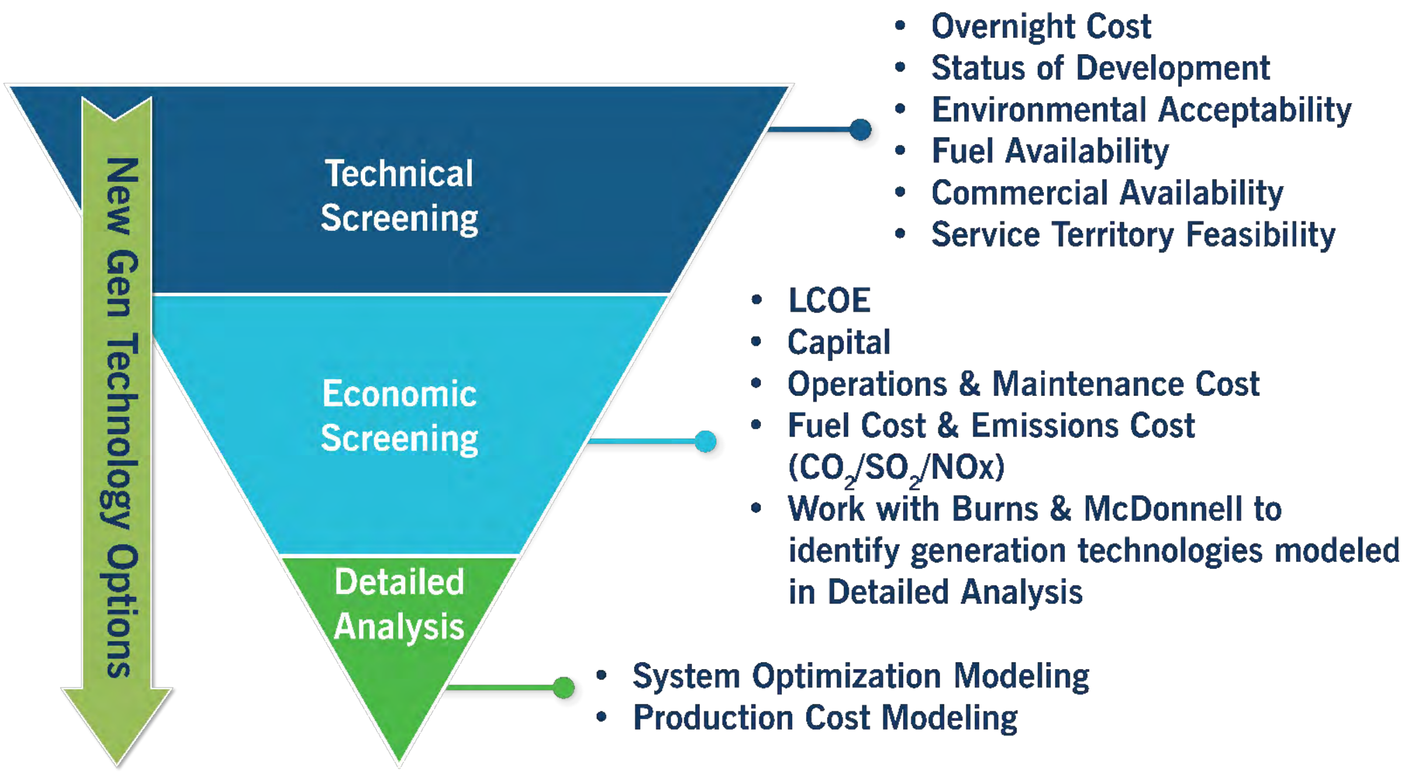
## 1. INTRODUCTION

The Company screens generation technologies prior to performing detailed analysis in order to develop a manageable set of possible generation alternatives. Generating technologies are screened from both a technical perspective and an economic perspective. In the technical screening, technology options are reviewed to determine technical limitations, commercial availability issues and feasibility in the Duke Energy Indiana service territory.

Economic screening is based on estimated levelized cost of electricity (LCOE) based on an assumed capacity factor over the life of the asset ($/MWh). The technologies must be technically and economically viable in order to be passed on to the detailed analysis phase of the IRP process. The Company develops LCOE data for dozens of technologies and works with Burns & McDonnell to determine the generation types defined in the Generic Unit Summary (GUS). The cost and operating data in the GUS are entered into the EnCompass model for economic selection.

FIGURE C.1

NEW GENERATION TECHNOLOGIES SCREENING PROCESS




## 2. TECHNICAL SCREENING

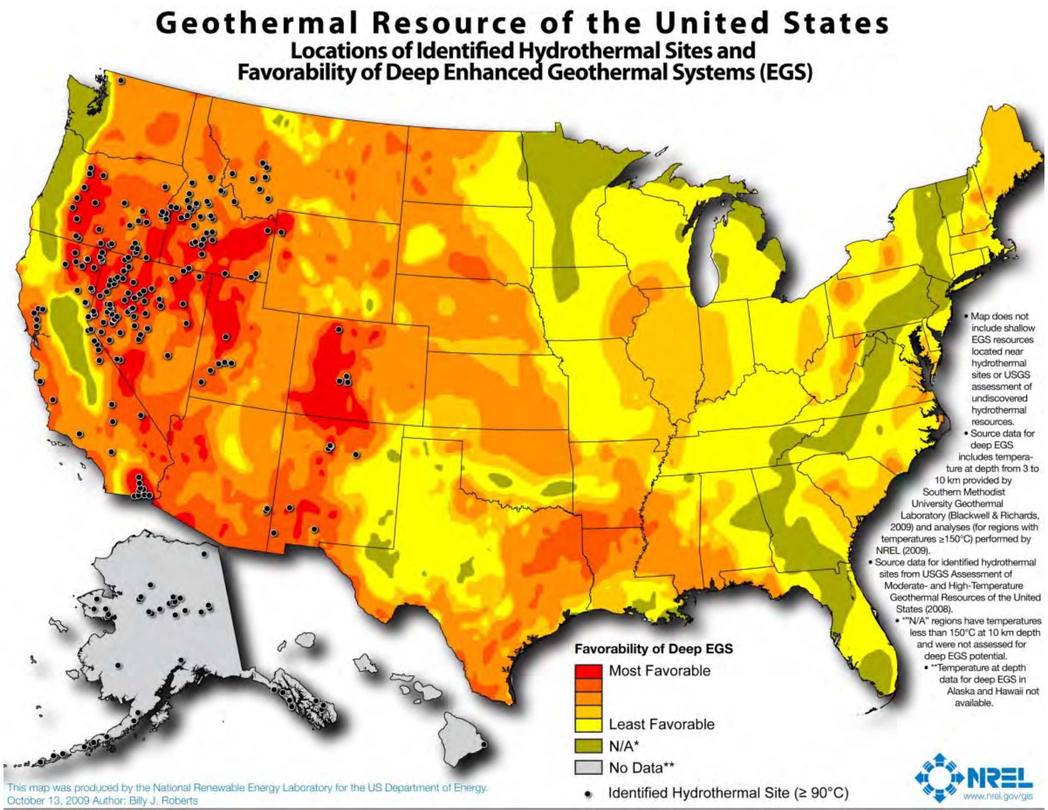
The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or cannot feasibly serve the Duke Energy Indiana service territory.

## TECHNOLOGIES EXCLUDED

A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

- **Geothermal** was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project. See Figure C.2, below.

## FIGURE C.2
## NREL GEOTHERMAL RESOURCE MAP OF THE US

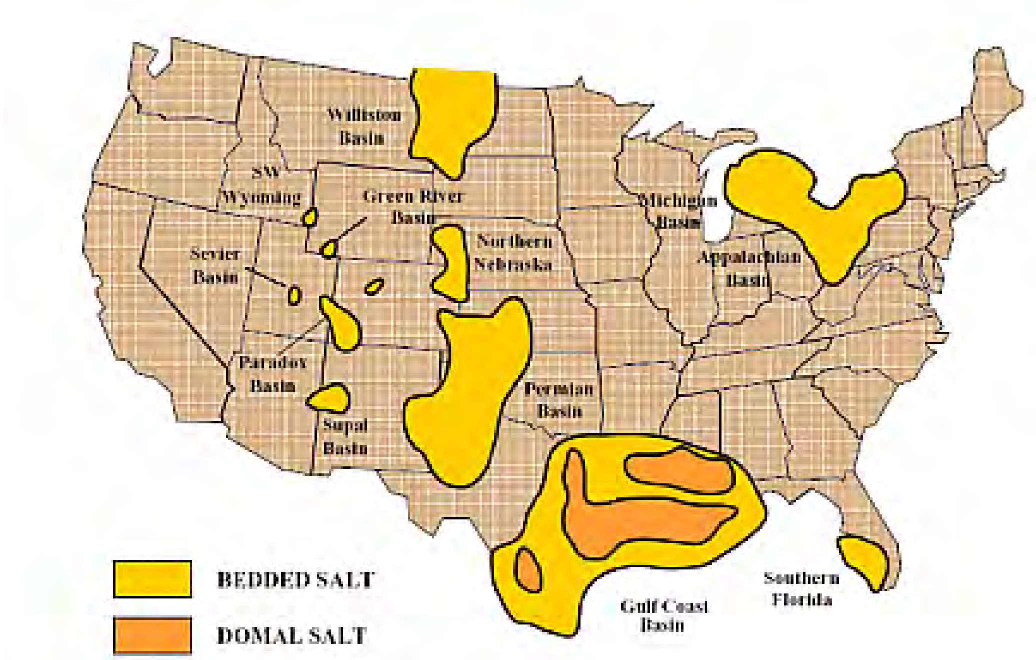



- **Pumped Storage Hydropower (PSH)** is the only conventional, mature, commercial, utility-scale electricity storage option available currently. This technology consumes off-peak electricity by pumping water from a lower reservoir to an upper reservoir. When the electric grid needs more electricity and when electricity prices are higher, water is released from the upper reservoir. As the water flows from the upper reservoir to the lower reservoir, it goes through a hydroelectric turbine to generate electricity. Many operational pumped storage hydropower plants are providing electric reliability and reserves for the electric grid in high demand situations. PSH can provide a high amount of power because its only limitation is the capacity of the upper reservoir.

Typically, these plants can be as large as 4,000 MW and have an efficiency of 76% - 85% (EPRI, 2012). Therefore, this technology is effective at meeting electric demand and transmission overload by shifting, storing, and producing electricity. This is important because an increasing supply of intermittent renewable energy generation such as solar will cause challenges to the electric grid. 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.

- **Compressed Air Energy Storage (CAES)**, although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. Traditional systems require a suitable storage site, commonly underground where the compressed air is used to boost the output of a gas turbine. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce, especially in the Indiana. However, above-ground compressed air energy storage (AGCAES) technologies are under development but at a much smaller scale, approximately 0.5 - 20MW. Several companies have attempted to develop cost effective CAES systems using above ground storage tanks. Most attempts to date have not been commercially successful, but their development is being monitored.

## FIGURE C.3
## COMPRESSED AIR ENERGY STORAGE (CAES) - POTENTIAL U.S. SALT CAVERN SITE DEPICTION, NETL




- **Liquid Air Energy Storage (LAES)** uses electricity to cool air until it liquefies, stores the liquid air in a tank, brings the liquid air back to a gaseous state (by exposure to ambient air or with waste heat from an industrial process) and uses that gas to turn a turbine and generate electricity. Although demonstrated through several pilot projects, the scaling of this technology and the resultant economics is not yet completely understood. As research and pilots continues with LAES, Duke Energy will continue to monitor as the technology offers bulk energy storage without the need for reservoir construction.

- **Advanced Nuclear Reactors** are typically defined as nuclear power reactors employing fuel and/or coolant significantly different from that of current light water reactors (LWRs) and offering advantages related to safety, cost, proliferation resistance, waste management and/or fuel utilization. These reactors are characteristically typed by coolant with the main groups including liquid-metal cooled, gas cooled, and molten-salt fueled/cooled. There are at least 25 domestic companies working on one or multiple advanced reactor designs funded primarily by venture capital investment, and even more designs are being considered at universities and national labs across the country. Duke Energy has been part of an overall industry effort to further the development of advanced reactors since joining the Nuclear Energy Institute Advanced Reactor Working Group at its formation in early 2015. Duke Energy will continue to allot resources to follow the progress of the advanced reactor community and will provide input to the proper internal constituents as additional information becomes available.
- **Fuel Cells**, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially viable/available for utility-scale application.
- **Supercritical $CO_2$ Brayton Cycle** is of increasing interest; however, the technology is still in the demonstration process. NET Power is the leading developer of the technology and is working on a pilot project. The early issues with the pilot show that

the technology has not yet reached commercial status, although recent news report have been more positive on the technology. Duke Energy will continue to monitor pilot and early commercial Supercritical $CO_2$ Brayton Cycle projects to determine if the technology passes the technical screening in future years. Although this technology is expected to produce fewer emissions than a combined cycle plant, the technology requires carbon capture and sequestration if powered by natural gas.

- **Offshore Wind** was eliminated because there are no suitable offshore locations for Indiana.
- **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 could be integrated into the steam cycle and support additional MW generation similar in concept to the purpose of duct firing a heat recovery steam generator. This technology, although attractive, has several hurdles yet to clear, including a clean operating history and initial capital cost reductions. This technology is very site-specific and Duke Energy will continue to monitor developments in the area of steam augmentation.
- **Hydrogen** as a fuel offers an advantage over traditional fossil fuels in not emitting carbon dioxide when burned. There has been substantial renewed interest by the industry in pursuing hydrogen as a replacement fuel for natural gas. Although promising, hydrogen as a utility fuel is still in the early stages from both a production and generation standpoint. Turbine manufacturers have proven successful with hydrogen/natural gas cofiring of up to 30-50% hydrogen by volume without significant gas turbine alterations in many of the combined cycle and combustion turbine plants currently in operation, dependent on gas turbine type. However, to

move to 100% hydrogen-fueled turbines substantial improvements in turbine technology are required. Additionally, hydrogen production would have to increase by many orders of magnitude to have ample supply to match the current production output of natural gas-fueled turbines. Although hydrogen screens out from a technical perspective due to readiness level, in some deep decarbonization portfolios that required significant $CO_2$ reductions by 2035, hydrogen was included as a fuel option for new CTs to help meet these aggressive targets. Duke Energy will continue to monitor hydrogen technology, both production and generation, to prepare for its potential future use as a natural gas fuel substitute.

- Additional Storage technologies continue to be developed and pursued by a variety of companies. The range of technologies is vast and include non-lithium-ion batteries, mechanical storage, thermal storage, and variants of pumped hydro storage. Although some storage technologies passed the technology screening, the majority are still in a pre-commercial status. These technologies continued to be studied as future options for generation and include lead acid batteries, sodium-sulfur batteries, metal-air batteries, subterranean pumped storage, gravitational energy, hydrogen, flywheel energy, liquid air energy, chilled water, molten salt, silicon, concrete, sand, and phase change storage. Duke Energy will continue to monitor the developments and pilots of the various storage options to determine which designs have reached commercial status.

## TECHNOLOGIES INCLUDED FOR SELECTION

A brief explanation of the technology additions for 2021 and the basis for their inclusion follows:

- **Small Modular Nuclear Reactors (SMR)** are generally defined as having a power output of less than 350 MW per reactor and utilizing water as the coolant. They typically have the capability of grouping a number of reactors in the same location to achieve the desired power generating capacity for a plant. In 2012, the U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to “promote the accelerated commercialization of SMR technologies to help meet the nation’s economic energy security and climate change objectives.” SMRs continue to gain interest as they contribute no emissions to the atmosphere and, unlike their predecessors, provide flexible operating capabilities alongside inherently safer designs. NuScale Power is the leader in SMR design and licensing in the US. A NuScale power module is expected to output 77 MW each, and a standard plant offering is expected to contain 6 or 12 modules. The NuScale received a certification from the Nuclear Regulatory Committee (NRC) in 2021, which allows utilities to pursue the design as a new commercial asset. The first NuScale module is expected to reach commercial status in the late 2020s timeframe.
- **Combined Cycle with Carbon Capture and Utilization and Storage (CCUS)** has been a technology under evaluation previously but has more importance in a carbon-constrained energy system. CCUS technology continues to be tested throughout the United States as a low-carbon technology deployment option. CCUS 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 also be considered to extend the life of operating plants while moving towards lower $CO_2$ emissions goals. CCUS will continue to be monitored by Duke Energy and evaluated as decarbonization technology to meet future low carbon requirements.

- **Flow batteries** utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks that hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference. Although flow batteries' capital costs project to be higher than Li-Ion batteries, flow batteries project to become most effective as the duration of the battery is increased due to energy capacity being dictated primarily by the size of the tanks. Therefore, flow batteries have been included in the technology options as a longer duration storage option. Although flow batteries are included as a technology option, the models did not select the technology due to 6-hour Li-Ion batteries being more economical for storage applications longer than 4 hours.

## GENERATION FLEXIBILITY

As more intermittent generation becomes associated with the system, there may be a greater need for generation that has rapid load changing capabilities. This generation would need to be dispatchable, possess desirable capacity/energy, and ramp at a desired rate. Some of the technologies that have 'technically' screened in possess these qualities or have the potential to in the near future. Effort is being made to value the characteristics of flexibility and quantify that value to the system. As a result of the flexible generation need, some features of "generic" plant's base designs have been modified to reflect the change in cost and performance to accomplish a more desired plant characteristic to diminish the impact of the intermittent generation additions. Additionally, in 2020 Duke Energy released a revision to its previous Climate Report with goals to reduce $CO_2$ from its generating facilities by 2030 and even deeper reductions by 2050. Duke Energy concluded that it would need new technologies that have not yet reached commercialization status that performed as Zero-Emitting Load-Following Resources (ZELFR). The load-following requirement comes from the flexibility need described above, and the zero-emission portion is to help Duke Energy meet its future climate goals. Duke Energy is evaluating several generation technologies that are considered pre-commercial to meet the ZELFR need. Technologies considered typically fall under the broad categories of advanced nuclear, advanced renewables, advanced transmission and distribution, biofuels, carbon capture utilization and storage (CCUS), fuel cells, hydrogen, long duration energy storage, and supercritical $CO_2$ Brayton Cycle. These emerging technologies are expected to be cost competitive with the current technology options in a $CO_2$-constrained future. CCUS is a site-specific technology, and the economics of the technology compared to alternative dispatchable, low carbon options (e.g., advanced nuclear) could be competitive with favorable geology. All of these technologies are expected to help Duke Energy meet future carbon reduction goals if they reach commercial status and are economically competitive.

## ENERGY STORAGE

Energy storage continues to become more economical and useful as additional variable energy resources are installed. Modeling included 4-hour and 6-hour Lithium Ion battery storage as technology selection options. Although battery storage cost still remains high in the near term, 4-hour and 6-hour storage are expected to have decreasing costs as more batteries 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.

## 3. ECONOMIC SCREENING

The Company selected the technologies listed below for the screening analysis in EnCompass for the Duke Energy Indiana territory. 2021 additions include Small Modular Reactors (SMRs) as a base load technology and Flow Battery Storage as a storage technology. Combined cycle, combustion turbines, and CHP are the most economic dispatchable baseload and peaking options available today. In a carbon-constrained future SMRs and combined cycle with Carbon Capture and Utilization and Storage (CCUS) are likely to be competitive in the post-2030 timeframe. Lithium Ion batteries are expected to be competitive with combustion turbines in the future based on their expected price decline.

Non-dispatchable options include onshore wind, solar PV, and solar PV plus storage. As the amount of solar PV deployed grows into the future, solar PV plus storage allows continued deployment of solar while preserving the ability to contribute to the system needs.

### Dispatchable

- **Base load –** 2 x 1,117 MW Nuclear Units
- **Base load –** 12 x 77 MW Small Modular Reactor (SMR) modules
- **Base load –** 1,157 MW – 2x1 J Class Advanced Combined Cycle (CC) (Fired)
- **Base load –** 775 MW – 2x1 F Class Advanced Combined Cycle (CC) (Fired)
- **Base load –** 17 MW – Combined Heat & Power (CHP, CT driven)

- **Peaking/Intermediate –** 201 MW, 12 x Reciprocating Engine Plant
- **Peaking/Intermediate –** 840 MW 4 x F-Frame Combustion Turbines (CTs)
- **Storage –** 50 MW / 200 MWh Li-ion Battery

Non-Dispatchable

- **Renewable –** 150 MW Wind - On-Shore
- **Renewable –** 75 MW Solar PV - Single Axis Tracking
- **Renewable –** 75 MW Solar PV plus storage (20 MW / 80 MWh Li-ion Battery)

## Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include but may not be limited to the following internal Departments: Duke Energy's Project Management & Construction, Emerging Technologies, and Corporate & Regulatory Strategy. The following external sources may also be utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). In addition, fuel and operating cost estimates are developed internally by Duke Energy, from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific but generally reflect the costs and operating parameters for installation in the Midwest. Finally, every effort is made to ensure that capital, operating and maintenance costs (O&M), fuel costs and other parameters are current and include similar scope across the technologies being screened. The supply-side screening analysis uses the same fuel prices for coal and natural gas as well as $NO_x$, $SO_2$, and

$CO_2$ allowance prices as those utilized downstream in the detailed analysis (discussed in Appendix A).

## 4. CAPITAL COST FORECAST

A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs, but the costs of all generation technologies technically screened in. The Technology Forecast Factors were sourced from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2020 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.

Using 2020 as a base year, an "annual forecast factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2018, April 2019).

From *NEMS Model Documentation 2018, April 2019*:

*"Uncertainty about investment costs for new technologies is captured in the ECP [Electricity Planning Submodule] using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.*

*Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity."*

The resulting Forecast Factor Table developed from the EIA technology maturity curves for each corresponding technology screened is depicted in Table C.4.

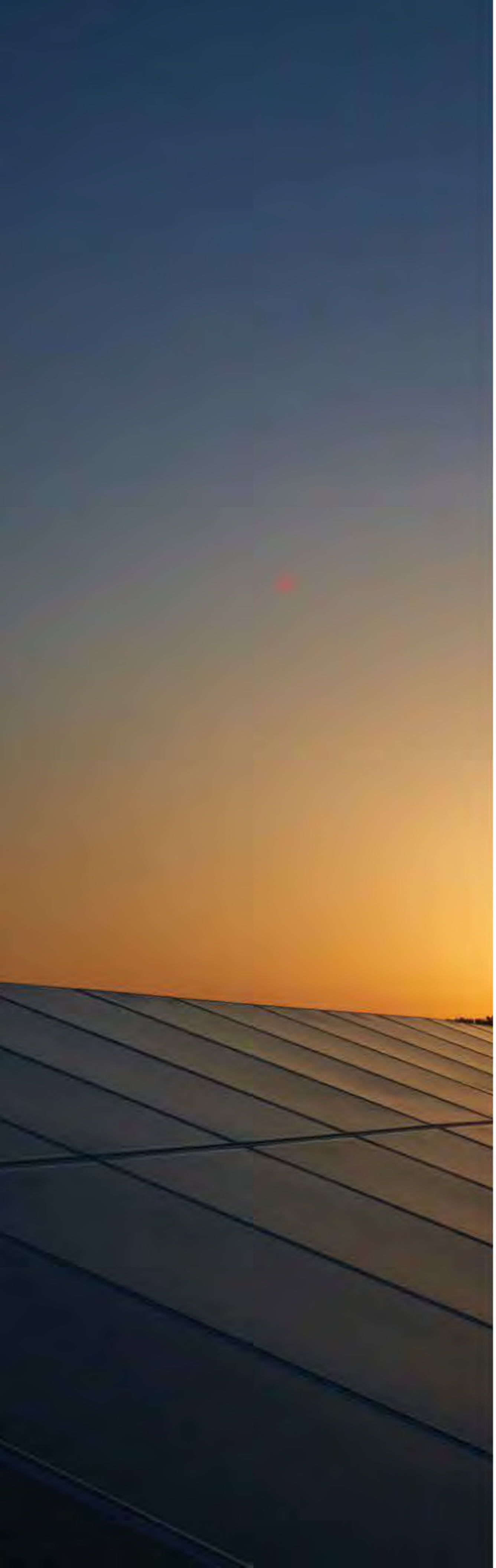
## TABLE C.4
## EXCERPT FROM FORECAST FACTOR TABLE BY TECHNOLOGY (EIA - AEO 2020)

| Year | Frame CT | Small Modular Reactor | Onshore Wind | Solar PV - Tracking | Solar PV - Tracking w/ storage | Li-Ion Battery Storage | 1x1 Combined Cycle | 2x1 Combined Cycle | 2x1 Combined Cycle w/ CCS |
|---|---|---|---|---|---|---|---|---|---|
| 2021 | 1 000 | 1.000 | 1.000 | 1.000 | 1 000 | 1.000 | 1.000 | 1.000 | 1 000 |
| 2022 | 1 000 | 1.000 | 1.010 | 0.928 | 0 923 | 0.910 | 1.000 | 1.000 | 1 000 |
| 2023 | 0 990 | 1.000 | 1.010 | 0.878 | 0 867 | 0.838 | 1.000 | 1.000 | 0 990 |
| 2024 | 0 970 | 1.000 | 1.010 | 0.841 | 0 817 | 0.748 | 0.990 | 0.990 | 0 990 |
| 2025 | 0 960 | 1.000 | 1.010 | 0.799 | 0.772 | 0.699 | 0.990 | 0.990 | 0 980 |
| 2026 | 0 950 | 0.980 | 1.000 | 0.765 | 0.736 | 0.656 | 0.970 | 0.970 | 0 960 |
| 2027 | 0 930 | 0.970 | 0.990 | 0.724 | 0.696 | 0.625 | 0.960 | 0.960 | 0 950 |
| 2028 | 0 910 | 0.950 | 0.970 | 0.694 | 0.667 | 0.600 | 0.940 | 0.940 | 0 930 |
| 2029 | 0 890 | 0.940 | 0.960 | 0.666 | 0.640 | 0.580 | 0.930 | 0.930 | 0 910 |
| 2030 | 0 880 | 0.920 | 0.950 | 0.650 | 0.628 | 0.561 | 0.910 | 0.910 | 0 890 |
| 2031 | 0 870 | 0.900 | 0.930 | 0.634 | 0.611 | 0.544 | 0.900 | 0.900 | 0 880 |
| 2032 | 0 850 | 0.890 | 0.920 | 0.625 | 0 594 | 0.526 | 0.890 | 0.890 | 0 860 |
| 2033 | 0 840 | 0.870 | 0.910 | 0.608 | 0 577 | 0.509 | 0.870 | 0.870 | 0 840 |
| 2034 | 0 820 | 0.860 | 0.890 | 0.600 | 0 569 | 0.491 | 0.860 | 0.860 | 0 830 |
| 2035 | 0 810 | 0.840 | 0.880 | 0.583 | 0 561 | 0.482 | 0.850 | 0.850 | 0 810 |

The EIA AEO forecast factors were blended with additional third-party capital cost projections (Guidehouse) for more rapidly developing technologies (Solar PV and Battery Storage) in order to provide a consistent forecast through the planning period for all technologies evaluated. The resulting Capital Cost changes for the technologies are shown in Table C.4.

## TABLE C.5
## ESTIMATED OVERNIGHT CAPITAL COSTS OF SELECTED TECHNOLOGIES ($/KW) [CONFIDENTIAL]

| Technology | Overnight Capital Cost - Winter Ratings |
|---|---|
| Conventional Nuclear | [redacted] |
| Small Modular Reactors (SMRs) (12 units) | [redacted] |
| 2x1 J-Class Combined Cycle | [redacted] |
| 2x1 J-Class Combined Cycle with CCS | [redacted] |
| 2x1 F-Class Combined Cycle | [redacted] |
| Combined Heat and Power | [redacted] |
| Reciprocating Engines (12 units) | [redacted] |
| F-Frame Combustion Turbine (4 units) | [redacted] |
| 4-Hour Li-Ion Battery Storage | [redacted] |
| **6-Hour Li-Ion Battery Storage** | [redacted] |
| Onshore Wind | [redacted] |
| Solar PV with Single Axis Tracking (SAT) | [redacted] |
| Solar PV with SAT Plus Li-Ion Storage | [redacted] |



DUKE ENERGY
INDIANA

# APPENDIX D

## DEMAND-SIDE RESOURCES

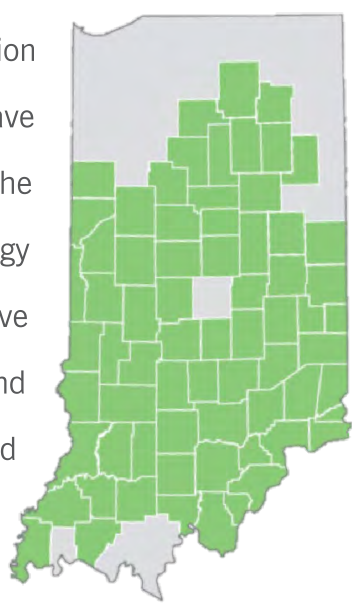
APPENDIX D

# DEMAND-SIDE RESOURCES

## A. INTRODUCTION

As part of the IRP, Duke Energy Indiana analyzes the impacts associated with new Energy Efficiency (EE) or Demand Response (DR) programs and any changes to existing EE or DR measures/programs. The portfolio of existing and future EE and DR measures/programs is evaluated within the IRP to examine the impact on the generation plan if the current set of measures/programs were to continue and proposed cost-effective programs were added. Additionally, all proposed and current EE and DR programs are evaluated in the IRP modeling process to determine if a given measure/program should be included in the IRP. The projected load impacts of all measures/programs included in the IRP's preferred portfolio.

## B. HISTORY OF DUKE ENERGY INDIANA'S PROGRAMS



Duke Energy Indiana has a long history associated with the implementation of EE and DR programs. 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. Implementing cost-effective EE and DR programs helps reduce overall long-term supply costs. Demand response programs include customer-specific contract options and innovative pricing programs approved in the Company's most recent base rate proceeding (Cause No. 45253). Duke Energy Indiana's EE and DR programs are primarily selected for implementation based upon their cost-effectiveness; however, there may be programs, such as a low income program, that are chosen for implementation due to desirability from an educational and/or societal perspective.

## C. CURRENT ENERGY EFFICIENCY PROGRAMS

Duke Energy Indiana's current EE program portfolio was approved by the Commission in Cause No. 43955 – DSM8 for the periods 2021-23.


## 1. RESIDENTIAL PROGRAMS

The following programs are currently approved to be offered through 2023:

### SMART $AVER® RESIDENTIAL

Program objectives include promoting energy savings and increased customer satisfaction through offering prescriptive incentives to residential customers for the purchase and installation of energy efficient measures designed to help customers improve the efficiency of their heating, ventilation, air conditioning (HVAC) system, building shell, in-ground swimming pool filtration, and water heating.

## HVAC EQUIPMENT

The HVAC Equipment program offers prescriptive incentives to residential customers for the purchase and installation of energy efficient measures designed to help customers improve the efficiency of their HVAC. As a result of increased federal energy efficiency standards for baseline (SEER rating) and higher cost for energy efficient equipment, the Company implemented modifications to offer a cost-effective Program. Modifications include a tiered incentive structure for HVAC equipment, an optional add-on measure, and a new referral channel component for eligible trade allies. Two incentive levels are made available for customers replacing HVAC equipment, based on the efficiency rating of the new unit installed, along with an add-on optional efficiency measure, for a smart thermostat. Customers can choose to combine the optional smart thermostat with the HVAC equipment replacement that will further improve the efficiency of the HVAC system. The smart thermostat is a programmable Wi-Fi enabled thermostat to help customers monitor and manage their HVAC from their smart device, and must be purchased and programmed as part of the HVAC equipment installation.

## ATTIC INSULATION AND AIR SEALING

Program incentives are provided to customers that have a trained participating contractor to seal and insulate the home's attic. Trained technicians utilize diagnostic equipment and proven procedures to identify and seal attic penetrations to improve the homes comfort and to reduce energy bills. After the sealing process is complete, attic insulation is installed to provide protection from higher attic temperatures. Trade allies submit incentive applications following successful completion of insulation and air sealing within the attic. The attic insulation and air sealing incentive is available one time per household.

## DUCT SEALING

Program incentives are provided to customers that have a certified contractor seal the home's duct system to reduce air leakage. Trained technicians utilize diagnostic equipment and proven procedures to seal leaks which can reduce energy bills and improve comfort. Trade allies submit incentive applications following successful completion of duct sealing measure. The duct sealing incentive will be paid one time per duct system.

## HEAT PUMP WATER HEATER

Program incentives are provided to encourage the adoption and installation of high efficiency heat pump water heaters in existing residences with electric water heating. Duke Energy Indiana served homeowners currently residing in or building a single-family residence, condominium, or duplex home are eligible for this program. Duke Energy program personnel establish relationships with plumbing contractors and national home improvement retailers who interface directly with residential customers. Incentives are paid directly to the customer following the installation of a qualified heat pump water heater and approval of a completed application.

## VARIABLE-SPEED POOL PUMP

Program incentives are provided to encourage the adoption and installation of energy efficient, variable-speed pool pumps for the main filtration of in-ground residential swimming pools. Duke Energy Indiana served homeowners currently residing in or building a single family residence with an in-ground swimming pool are eligible for this program. Duke Energy program personnel establish relationships with pool professionals who interface directly with residential customers. Incentives are paid directly to the customer following the installation of a qualified variable-speed pool pump and approval of a completed application.

## REFERRAL CHANNEL

The referral component of the Program, Find It Duke, is a new delivery channel that provides a free referral service to customers to enhance program awareness and participation. The service simplifies the customer's decision-making around energy efficiency purchases and takes the guesswork out of finding reliable, qualified contractors with competitive offers. This delivery channel supports the Company's role as an energy efficiency program administrator while building trusted partnerships with customers and HVAC and home performance contractors as well as home builders ("Trade Allies") who interface directly with residential customers.

The Referral Channel offers high achieving Trade Allies in the Program the ability to receive referral services. The Referral Channel establishes designations between registered Trade Allies as referred or non-referred. As part of the Program, the Company generates leads for qualified, referred Trade Allies by identifying prospective customers with interest in eligible incentivized energy efficiency upgrades and/or subsequent non-incentivized services.

Trade Ally eligibility to participate in the referral channel is based upon previous registration in one or more of the Program incentive measures, and meeting minimum performance requirements which demonstrates their active engagement and promotion of the Program. Performance criteria include such metrics as quantity and accuracy of qualifying rebate applications submitted, customer service rating, and quality assurance. Trade Allies who meet the performance criteria may elect to opt-in to participate in the referral channel. These Trade Allies will be able to receive referrals from the Company when requested by a customer. Customers will have the option of contacting one or more of the referred Trade Allies. The Trade Ally will pay the Company a set fee for receiving customer referrals, structured in a manner that encourages sales of qualifying, high efficiency products and services. These fees received by the Company from the referral channel are paid back into the program to improve cost effectiveness.

Duke Energy Indiana continues to pay the customers of the referred and non-referred Trade Allies an energy efficiency incentive for qualifying eligible measures.

## FREE LED PROGRAM

The Free LED program is designed to increase the energy efficiency of residential customers by offering customers LEDs to install in high-use fixtures within their homes. The LEDs are offered through an on-demand ordering platform, enabling eligible customers to request LEDs and have them shipped directly to their homes. Eligibility and participation limits are based on past participation in the CFL program and other Duke Energy programs distributing lighting. The maximum number of bulbs available for each customer is 15, but customers may choose to order less. Bulbs are available in 3, 6, 8, 12 and 15 pack and include 9 watts dimmable LEDs.

## SPECIALTY LIGHTING & OTHER ENERGY EFFICIENT PRODUCTS

The Duke Energy Savings Store is an extension of the on-demand ordering platform enabling eligible customers to purchase a variety of energy efficient products. These products are shipped directly to customers' homes. The Savings Store offers a variety of products including specialty Light Emitting Diodes lamps ("LEDs") lighting, including; Reflectors, Globes, Candelabra, 3 Way, Dimmable and A-Line type bulbs, smart thermostats, smart strips, water savings products, dehumidifiers, air purifiers, & LED fixtures. Duke Energy incentive levels vary by bulb type and product, the customer pays the difference, including shipping. The amount of product each customer can purchase is restricted by an account limit per product type, but customers may choose to order more without the Duke Energy incentive.

The primary goal for this program is to help customers lower their energy bills and to remove inefficient equipment from the electric grid. This program educates customers about energy consumption and how it compares to high efficiency alternatives.

The Savings Store is managed by a third party vendor, Energy Federation Inc. ("EFI"). EFI is responsible for maintaining the Savings Store website and fulfilling customer purchases. The Savings Store landing page provides information about the store, products, account information and order history. Support features include a toll free number, package tracking, live chat and frequently asked questions. Educational information is available to help customers with their purchase decisions. The educational information provides information on product types, application types, compatibility, savings, benefits, understanding watts versus lumens  and recycling/safety tips.

Duke Energy Indiana residential customers with an active residential account are eligible to participate and must agree to terms and conditions, including the condition that all products will be installed at the accounts premise address, to participate in this program.

## RETAIL LIGHTING

This upstream, buy-down retail-based lighting program works through lighting manufacturers and retailers to offer discounts to Duke Energy Indiana customers selecting incentivized LEDs and energy-efficient fixtures at the shelf for purchase at the register. Retailers, such as, but not limited to, Home Depot, Lowe's, Habitat ReStore, and Dollar Tree will be evaluated at the store level for possible inclusion in this program.

This program encourages customers to adopt energy efficient lighting through incentives on a wide range of LED products, including Reflectors, Globes, Candelabra, 3 Way, Dimmable, as well as fixtures. Customer education is imperative to ensure customers are purchasing the correct bulb for the application in order to obtain high satisfaction with energy efficient lighting products, ensuring subsequent energy efficient purchases.

The incentive amount varies by product type and the customer pays the difference as well as any applicable taxes. Pack limits will be in place and enforced to the best of the retailers' ability.

CLEAResult is the implementation vendor for the Retail program. CLEAResult utilizes a field team to promote and monitor the program at the participating retail locations. A toll free call center and website will be hosted by CLEAResult to provide program information to Duke Energy Indiana customers. The website includes a retailer locator where customers can enter their zip code and search for retailers and specific bulb and fixture types in their area. A tool available to customers is an interactive savings calculator, which explains the different types of lighting technologies, helps guide customers to the appropriate bulb/s for their application and provides an estimate of energy and monetary savings. Eligible program participants include Duke Energy Indiana residential customers.

The primary goals for this program are to help customers lower their energy bills and to remove inefficient equipment from the electric grid. This program educates customers about energy consumption attributed to lighting and how to reduce their consumption by using high efficiency alternatives.

## SAVE ENERGY AND WATER KIT

The Save Energy and Water Kit (SEWK) is designed to increase the energy efficiency of residential customers by offering customers energy efficient water measures, and Insulated Pipe Wrap to install in high-use fixtures within their homes. These energy saving devices will be offered to eligible customers and by opting in, customers can have these devices shipped directly to their homes, free of charge. Eligibility is based on past campaign participation (including this Program and any other programs offering energy efficient water devices that Duke Energy Indiana has offered to Indiana customers) and the customer must have an electric water heater. Customers receive a kit with varying amounts, based on the size of the home, of the following devices: bath and kitchen aerators, state-of-the-art shower heads and insulated pipe tape. Customers also now have the ability to upgrade the showerhead(s) included in their kit to a form factor that better meets their needs. Upgrade options include a wider pattern showerhead and a shower wand. Customers will be able to upgrade showerheads at Program cost, there is no margin associated with these measures. Upgrades are intended to increase In-Service Rates and Customer Satisfaction. The kit also includes directions and items to help with installation.

This programs implementation vendor is Energy Federation, Inc. (EFI), who will receive and fulfill orders and provide support for damaged and missing orders. In addition to processing Business Reply Card orders, EFI also maintains the Save Energy and Water Kit Online store where customers can redeem the offer online. The Online Store helps reduce print and postage costs as well as paper waste and enables the ability for customers to upgrade the showerhead(s) in their kit. For customer service, EFI will maintain a call center to answer questions, provide installation support, and take orders.

## LOW INCOME NEIGHBORHOOD

The Low Income Neighborhood program, known as the Neighborhood Energy Saver Program, or NES, 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 receive a walk-through energy assessment and one-on-one education. Additionally, the customer receives a comprehensive package of energy efficient measures. Each measure listed below is installed or provided to the extent the measure is identified as energy efficiency opportunity based on the results of the energy assessment.

1. Energy Efficient Bulbs - Up to 15 LED bulbs to replace incandescent bulbs.
2. Electric Water Heater Wrap and Insulation for Water Pipes.
3. Electric Water Heater Temperature Check and Adjustment.
4. Faucet Aerators - Up to three low-flow faucet aerators.
5. Showerheads - Up to two low-flow showerheads.
6. Wall Plate Thermometer –one per home.
7. HVAC Winterization Kits – Up to three winterization HVAC kits for wall/window air conditioning units along with education on the proper use, installation and value of the winterization kit as a method of stopping air infiltration.
8. HVAC Filters - A one-year supply of HVAC filters will be provided along with instructions on the proper method for installing a replacement filter.
9. Refrigerator Magnet – highlighting the top 10 energy tips.
10. Air Infiltration Reduction Measures - Weather stripping, door sweeps, caulk, foam sealant and clear patch tape will be installed to reduce or stop air infiltration around doors, windows, attic hatches and plumbing penetrations.

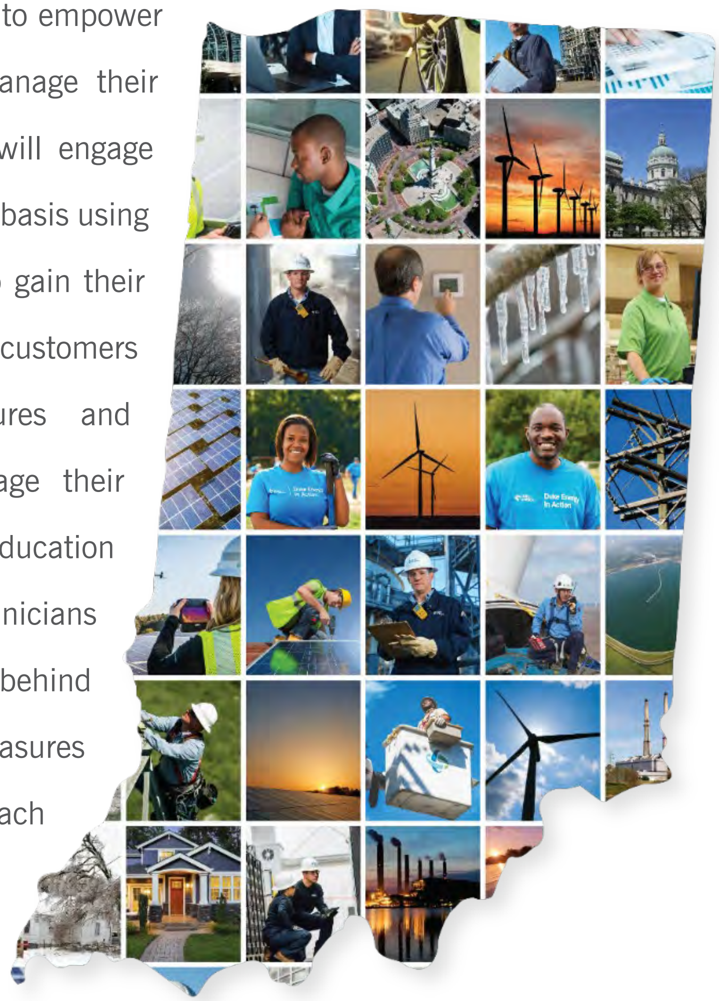
Targeted low-income neighborhoods qualify for this program if approximately 50% of the households have incomes of <200% of the Federal Poverty Guidelines. Duke Energy

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 in the target neighborhoods with electric service provided by Duke Energy Indiana.

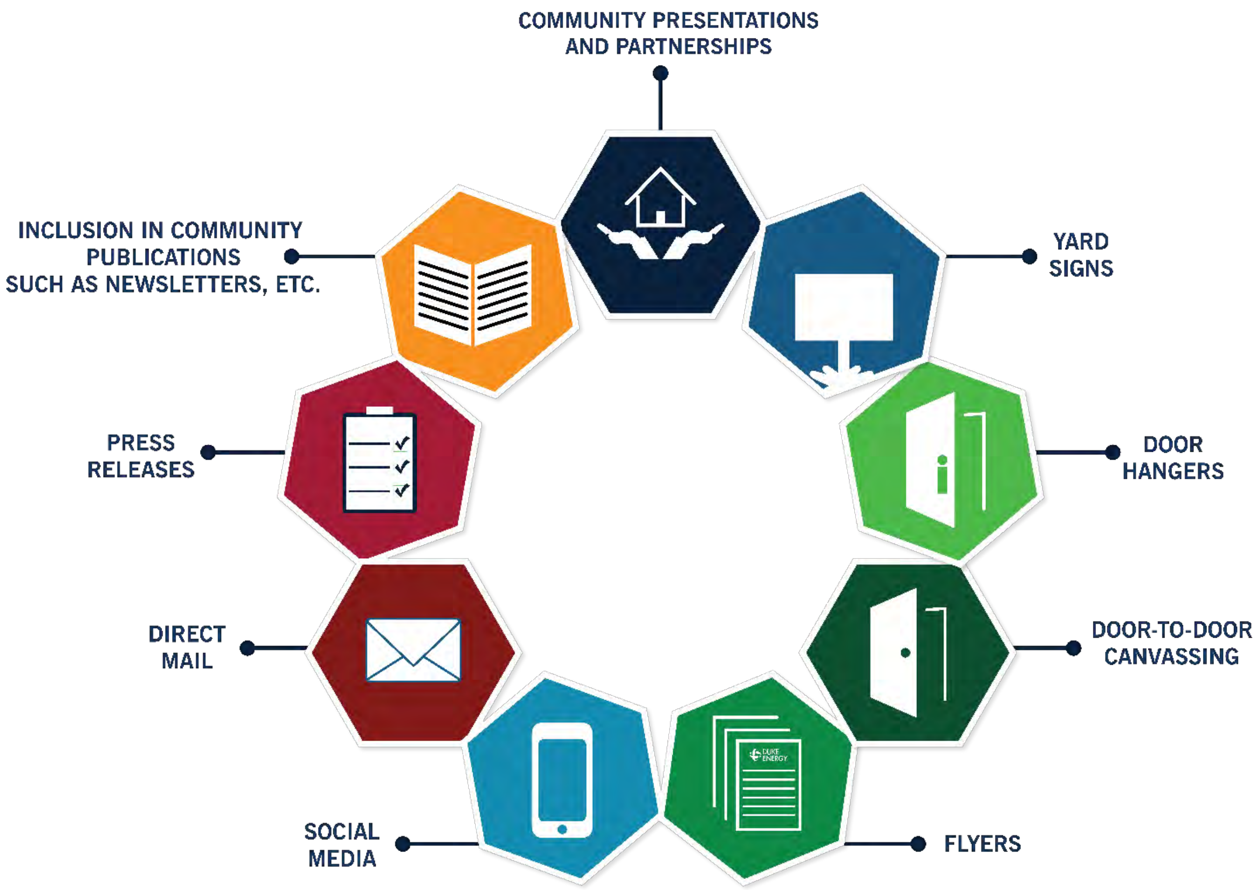
The community approach offered by this program offers the following benefits:

- 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

The primary goal for this program is to empower low-income customers to better manage their energy bills. Duke Energy Indiana will engage low-income customers on a personal basis using a grass roots marketing approach to gain their trust. Crucial steps include providing customers with free energy saving measures and educating them on how to manage their energy needs. After a one-on-one education session, energy efficiency technicians provide customers with leave-behind materials to emphasize the measures installed, the importance of each measure, and how to maintain the measure. The marketing strategy for this program will focus on a grassroots approach.



Below are some of the marketing strategies Duke Energy Indiana may utilize to meet participation goals:




## LOW INCOME WEATHERIZATION

The Low Income Weatherization program is designed to help Duke Energy Indiana income-qualified customers reduce their energy consumption and lower their energy cost. This Program specifically focuses on owner occupied, single family homes meeting income qualification levels based on DOE standards (i.e., income below 200% of the federal poverty level). The program will include renters. This program will provide direct installation of weatherization and energy-efficiency measures including refrigerator and furnace replacement.

Duke Energy Indiana will utilize the Indiana Housing and Community Development Authority (IHCDA) to administer the program, partnering with the current Indiana Community Action Association weatherization network.

Measures available through the program include:

- Electric Heating System Tune-up & Cleaning
- Electric Heating System repair up to $600
- Mini-split heat pump
- Water Heater Wrap for electric water heaters
- Water Heater Pipe Wrap
- Cleaning / replacing electric dryer vents
- Energy Efficient Light Bulbs
- Water saving shower heads and aerators
- Weather-stripping doors & windows
- Energy Education
- Additional cost effective measures using the National Energy Audit Tool ("NEAT") audit where the energy savings pay for the measure over the life of the measure as determined by a standard heat loss/economic calculation. Such items can include but are not limited to attic insulation, air sealing, wall insulation, crawl space insulation, floor insulation, duct sealing.

Up to $750 can be spent on a home for Health & Safety issues which may prevent them from receiving weatherization assistance. In addition, refrigerator replacement will be available to income-eligible customers whose refrigerators test to be inefficient or >10 years old, including renters.

## MULTIFAMILY ENERGY EFFICIENCY PRODUCTS & SERVICES

The Multifamily Energy Efficiency Products & Services program allow 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. Franklin Energy is the implementation vendor who delivers this program.

This program's objective is the installation energy efficient measures including:

a. LED Lighting
b. Kitchen Faucet Aerators*
c. Bathroom Faucet Aerators*
d. Showerheads*
e. Hot Water Pipe wrap*

*Water measures are only available if water is heated electrically

Measures are installed by program crews during scheduled direct install visits and the crews are accompanied by property personnel. Franklin Energy installers carry tablets to keep track of what is installed in each apartment and what energy inefficient products are removed.

After installations are complete, Quality Assurance (“QA”) inspections are conducted on approximately 20% of properties that completed installations in a given month. The QA inspections are conducted by an independent third party.

Promotion of this program is primarily focused on personalized outreach to targeted property managers/owners where each unit is individually metered and has electric water heating. Program collateral stresses the benefits of this program to property managers. Benefits include  higher occupancy rates, lower energy bills, lower water bills and lower tenant turnover. In addition, tenants will be informed about the energy efficient measures installed in their residence and how these new measures will help reduce their energy costs.

Once enrolled, the program provides property managers with a variety of marketing tools to create awareness of this program to their tenants. Materials include Program letters to each tenant informing them of what is being installed and when the installation will take place. Tenants are provided an educational leave-behind brochure when the installation is complete. The brochure provides additional details on the installed measures as well as an opportunity to fill out a customer satisfaction survey to provide valuable Program feedback. Once the installation is complete the property will receive a complimentary window cling highlighting the participation in the program.

## 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. The kit may include measures such as energy efficient lighting and water measures, outlet/switch gaskets, weather stripping and energy saving tips.

The primary goal is to empower customers to better manage their energy usage. Example recommendations might include the following:

- Turning off vampire load equipment when not in use
- Turning off lights when not in the room
- Using energy efficient lighting in light fixtures
- Using a programmable thermostat to better manage heating and cooling usage

- Replacing older equipment
- Adding insulation and sealing the home

This program targets Duke Energy Indiana residential customers that own a single family home. Program participation is primarily driven through bill inserts and targeted mailings; however, for those who elect to receive offers electronically, email marketing will be used to supplement. Additional channels include but are not limited to mass media, billboards, community events, and online awareness via the Duke Energy website as well as through online services.

## MY HOME ENERGY REPORT

My Home Energy Report (MyHER) program provides customers with a comparison of their energy usage to similar single family 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 behavior. The paper reports are mailed up to 8 times and emailed up to 12 times a year for single family dwellings. Multifamily dwellings receive up to 6 paper reports if they do not have an email and up to 4 paper reports and 12 electronic reports throughout the year. MyHER Interactive, a portal, provides similar information as the printed report but also provides the ability to create a savings plan, see how energy is used in the home by end use, provides an energy expert to respond to customer questions and delivers weekly email challenges.

MyHER is a foundational part of the existing EE portfolio because it provides customers with an awareness of their usage and provides them information they can use to reduce their monthly electric bill, including information about other EE measures available to them through the Duke Energy Indiana Residential EE Portfolio.

The objective of this program is to generate kWh savings, increase customer satisfaction and educate customers on other Energy Efficiency offers from Duke Energy Indiana.

The paper report MyHER program is an opt out program that automatically creates and sends reports for eligible customers.  The MyHER Interactive portal is an opt in program and is marketed through messages in the printed report and email marketing campaigns. Sweepstakes offers are used to encourage enrollment on the Interactive Portal.

## ENERGY EFFICIENCY EDUCATION PROGRAM FOR SCHOOLS

The Energy Efficiency Education Program for Schools is available to students enrolled in public and private schools who reside in households served by Duke Energy Indiana. The current curriculum administered by The National Theatre for Children (NTC) targets K-12 grade students. The primary goal of this program is to educate students on the importance of energy conservation and teach them how 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 participating student household.  The program also includes a fun and educational game app, Kilowatt Krush, which is available to all students who see a performance, regardless of kit eligibility.

The Program provides principals and teachers with an innovative curriculum that educates students about energy, resources, how energy and resources are related, ways energy is wasted and how to be more energy efficient. The centerpiece of the curriculum is a live theatrical production focused on concepts such as energy, renewable fuels and energy efficiency performed by two professional actors. Teachers receive supportive educational material for classroom and student take home assignments. The workbooks, assignments and activities meet state curriculum requirements.

Students are encouraged to request an Energy Efficiency Starter Kit. The kit contains specific energy efficiency measures to reduce home energy consumption. The kit is available at no cost to student households at participating schools who are Duke Energy Indiana customers and have not received a kit in the last 36 months. Program participation is driven by student households that elect to receive the Energy Efficiency Starter Kit.

The National Theatre for Children is responsible for all marketing campaigns and outreach. NTC utilizes direct mail and email sent directly to principals to market the Program.

## POWER MANAGER®

Power Manager® is a residential load control program. It is used to reduce electricity demand by controlling residential air conditioners, electric water heaters, and thermostats during periods of peak demand. A load control switch is attached to the outdoor air conditioning unit of participating customers. For water heaters, the switch is installed on or near the appliance. The device enables Duke Energy Indiana to cycle central air conditioning systems off and on when the load on Duke Energy Indiana's system reaches peak levels. The water heater switch will enable Duke Energy Indiana to cycle off electric water heaters during times of high electric demand—year round.

The objective of the Power Manager® program is to provide customer bill savings to customers through reducing their usage during times of high system loads or high wholesale energy prices. This program delivers direct savings to participating customers in the form of bill credits as well as reduces rates for all customers by providing a cheaper capacity option than building generation for the small number of hours that the program impacts.

Customers residing in single family homes participating in this Program receive a one-time enrollment incentive and monthly bill credits during the months of May – September for Power Manager® participation. Customers who select Option A, which cycles their air conditioner to achieve a 1.0 kW load reduction, receive a $25 credit at installation. Customers selecting Option B, which cycles their air conditioner to achieve a 1.5 kW load reduction, receive a $35 credit at installation. The bill credit provided for each cycling event is based on: the kW reduction option selected by the customer. For each control season (May through Sept), customers will receive a credit of $7.50 for Option A and $10 for Option B in credits. For water heaters, participating customers receive a one-time incentive of $5 and a bill credit for Power Manager® participation. Annually, customers will receive a bill credit of $6 in credits.

For the 2020-2023 portfolio, Duke Energy Indiana included our Bring Your Own Thermostat (BYOT) program into our Power Manager suite. BYOT is a residential Demand

Response (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. Since it was first introduced in 2012, over a dozen utilities have implemented, or are planning to implement BYOT pilot programs in the United States. Duke Energy Indiana is partnering with a third-party vendor who has contracts with multiple thermostat manufacturers to offer demand response through aggregation of the different thermostat models.

The program will be marketed to customers through participating device manufacturers who offer utility branded marketing and enrollment services. One of the significant advantages of Smart Thermostats is its ability to have two way communication. Agreements with the aggregation vendor and the thermostat manufacturers include the ability to send messages to device owners inviting them to participate in their utility's DR program. Communication may include, but is not limited to messages on the unit, email and text messages. Interested customers are brought into the enrollment system, which can vary by manufacturer. In addition to the unit manufacturer communication, the company may use a number of channels including, but not limited to online marketing direct mail and social media.

For BYOT, Duke Energy Indiana hopes to reach new customers who have not traditionally participated in demand response. For their participation, customers are provided annual recurring monetary incentives via gift cards or bill credits.

## 2. NON-RESIDENTIAL PROGRAMS

### SMART $AVER®

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 in order 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 in 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 Duke Energy Indiana Program.

This program is delivered to customers through three incentive categories: Prescriptive, Custom and Performance.

## PRESCRIPTIVE INCENTIVES

Prescriptive Incentives are pre-determined, fixed incentives for common energy efficiency equipment. Pre-approval is not required; eligibility requirements and incentive amounts are published on the application form posted to the Duke Energy website.

This program promotes prescriptive incentives for the following technologies – lighting, HVAC, pumps, variable frequency drives, food services, process equipment, and information technology equipment. Equipment and incentives are predefined based on current market assumptions and Duke Energy's engineering analysis. The eligible measures, incentives and requirements for both equipment and customer eligibility are listed in the applications posted on Duke Energy'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 Nonresidential 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.
Prescriptive Incentives are offered to customers through multiple channels, including an application form (paper and electronic), the online Energy Efficiency Store, and Midstream network. Additional channels may be added in the future, in order to reach as many customers as possible.

## CUSTOM INCENTIVES

Unlike Prescriptive Incentive 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. There are two potential approaches for applying for Custom Incentives; Classic Custom and Custom Calculation Tools. Application documents vary slightly depending on the approach taken. The two approaches differ in terms of the method by which energy savings are calculated. Customers eligible for the Custom Calculation Tools calculations approach may elect to apply under the Classic Custom approach if that is their preference.

The following application forms are located on the Duke Energy website under Smart $aver® Custom Incentives (Business and Large Business tabs). These forms may be completed and returned to the program via e-mail or through use of the Online Application Portal.

- Custom Application – Administrative Information
- Energy Savings Calculations & Basis
    - Classic Custom Approach (> 700,000 kWh or no applicable Custom to Go calculator)
    - Variable Frequency Drives
    - Energy Management Systems (HVAC)
    - Compressed Air Systems
    - Lighting
    - General (for technologies not listed above)

- Custom Calculation Tools (< 700,000 kWh unless otherwise noted and applicable)
    - Variable Frequency Drives (Fans & Pumps)
    - HVAC/Energy Management Systems
    - Compressed Air Systems
    - Lighting (>700,000 kWh is supported)
- Application Assistance – Customer can elect to have a Duke Energy contracted vendor complete the Smart $aver Application on their behalf for a fee ($300).
- Calculation Assistance – Customer can elect to have a Duke Energy contracted vendor complete calculations on their behalf for a fee

    Lighting calculations: $700

    - Simple single measure (i.e. compressed air): $1,500
    - HVAC or process equipment: $2,800

The Smart $aver® Custom Incentive 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 marketed as the "Smart Saver Calculation Tools".

## PERFORMANCE INCENTIVES

Duke Energy Indiana's $mart $aver® Performance Incentive provides a mechanism to encourage the installation of high efficiency measures not eligible for Smart $aver® Prescriptive or Custom Incentive payments. $mart $aver® Performance Incentive has been designed to complement the Company's Smart $aver® Prescriptive and Custom measures, 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 end result. The types of measures that will be covered by $mart $aver® Performance Incentive will include some combination of unknown building conditions or system constraints, coupled with uncertain operating, occupancy, or production schedules. The specific type of measures will be included in the contract with the Customer.

To receive payment under this program, the customer must submit an application and receive approval before making a decision to implement the project. An estimated total project savings will be calculated and agreed to by the applicant and the Company. Program incentives will be based on the published incentive rate schedule. Incentives paid under Performance Incentive may be divided into multiple payments. When applicable, the Initial incentive payment will be made upon completion of the project, and following a review and approval by the company. This initial payment will be based on a portion of the initial estimated total savings for the project that will be achieved with a high degree of confidence. Subsequent and, ultimately, Final Measured Incentive Payment(s) will be made as savings are confirmed and will be equal to the applicable incentive rate multiplied by the verified savings amount. The percentage of payment made for the initial incentive versus the verified incentive payment amount will be made on a project-by-project basis according to the measure of uncertainty assigned to the project.

Performance Incentives will leverage the application materials and processing channels established in the Smart $aver® Custom program, as well as, the same promotional channels.

Due to the different types of projects, and the range of variables involved with these different categories of energy efficiency measures, the program Evaluation, Measurement & Verification will be performed separately for Prescriptive, Custom and Performance measures.

Optional energy assessments are available to identify and/or evaluate energy efficiency projects and measures. The scope of an energy assessment may include but is not limited to facility energy audit, new construction/renovation energy performance simulation, system energy study and retro-commissioning service. Payments are available to offset a portion of the costs of a qualifying energy assessment. The Company may vary the percentage of energy assessment payment based on the facility size, age, equipment, and other criteria that could affect the amount of energy efficiency opportunities identified. All, or a portion of, the energy assessment payment may be contingent on the customer implementing a minimum amount of cost effective energy efficiency measures within a set timeframe. A Virtual Energy Assessment is now offered through a Duke Energy contracted vendor which requires no onsite visit and at no cost to the customer.

## SMALL BUSINESS ENERGY SAVER

The purpose of Duke Energy Indiana's Small Business Energy Saver (SBES) program is to reduce energy usage through the direct installation of energy efficiency measures within qualifying small and medium non-residential customer facilities. SBES 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. The SBES program 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.

All aspects of SBES are managed by a Duke Energy-authorized program vendor. Program participants receive a free, no-obligation energy assessment of their facility followed by a recommendation of energy efficiency measures to be installed in their facility along with the projected energy savings, costs of all materials and installation, and up-front incentive amount from Duke Energy Indiana. Upon receiving the results of the energy assessment, if the customer decides to move forward with the proposed energy efficiency project, the customer makes the final determination of which measures will be installed. The energy efficiency measure installation is then scheduled at a convenient time for the customer and the measures are installed by a Duke Energy-authorized vendor electrical subcontractor.

The SBES 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 heating ventilation and air conditioning (HVAC) applications. Lighting measures such as interior and exterior light emitting diode (LED) fixtures, screw-in LED lamps; LED tubes and LED retrofit kits; LED exit signs; and occupancy sensors may be offered. All lighting measures offered are Consortium for Energy Efficiency (CEE), ENERGY STAR, or Design Lights Consortium (DLC) qualified products. Refrigeration measures may include new electronically commutated (EC) motors, anti-sweat heater controls, evaporator fan controls, LED refrigeration case lighting, beverage machine/novelty cooler controls, and automatic door closers for walk-in freezers. HVAC upgrades such as unitary, split systems, and air sourced heat pumps and programmable thermostats may be included. In anticipation of technological advancements, Duke Energy Indiana proposes the flexibility to incentivize additional cost effective measures where appropriate within the lighting, refrigeration and HVAC fields. In order to encourage participation within this hard-to-reach customer segment, Duke Energy Indiana provides an upfront customer incentive for up to 80 percent of the total cost of installed measures. Incentives will be provided based on Duke Energy Indiana's cost effectiveness modeling to ensure cost effectiveness over the life of the measures.

Duke Energy Indiana's incentive payment for any installed measures will be paid directly to the program vendor upon verification that the energy efficiency measure(s) have been installed. The program vendor is only compensated by Duke Energy Indiana for energy savings produced through the installation of energy efficiency measures. All project costs above the incentive amount will be the responsibility of the customer and paid based upon payment terms arranged between the customer and program vendor. The program vendor will offer interest-free extended payment options to the customer, to further minimize any financial barriers to participation.

The objective of the Small Business Energy Saver (SBES) program is to enable the direct installation of high efficiency equipment in existing small and medium non-residential facilities by removing common barriers to energy efficiency program participation.

This program may be promoted through various marketing channels that include, but are not limited to:

- Direct mail (letters and postcards to qualifying customers)
- Duke Energy website
- Community outreach events
- Small Business Group outreach events
- Paid advertising/mass media
- Social media promotions
- Door to door canvassing

Marketing efforts will be designed to create customer awareness of this program, to educate customers on energy saving opportunities and to emphasize the convenience of participation in SBES.

## 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. 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 (DR) participation, and earn an incentive based upon that selection.
Both thermostat and switch customers have the same DR participation options, and receive the same DR incentives.

Power Manager® for Business will be offered to business customers with qualifying air conditioning systems, summer weekday energy usage and broadband/Wi-Fi internet. Customers must agree to have the control device installed on their A/C system and to allow Duke Energy Indiana to control their A/C system during Power Manager® events. Qualifying air conditioning systems include:

- Individual split air conditioning systems
- Rooftop Units
- Packaged terminal air conditioners (PTACs)

Customers participating in this Program receive an incentive based on upon the level of demand response cycling they select:

- 30% cycling:  $50 per DR summer season (per device)
- 50% cycling:  $85 per DR summer season (per device)
- 75% cycling: $135 per DR summer season (per device

The incentive will be paid out after installation of the device(s) and then annually. Devices are installed at the customer premise at no charge to the customer.

The objective of the Power Manager® for Business program is to provide customer bill savings to customers through reducing their usage during times of high system loads or high wholesale energy prices. This program delivers direct savings to participating customers in the form of bill credits as well as reduces rates for all customers by providing a cheaper capacity option than building generation for the small number of hours that the program impacts. In addition, this program is reaching a subset of the customer base that previously has not been well-served by similar demand response programs (too small for PowerShare® and not eligible for the residential Power Manager® program).

Power Manager® for Business will be marketed through targeted direct mail campaigns, targeted e-mail campaigns, outbound telemarketing, on Duke Energy's Web site and via cross selling with the Small Business Energy Saver Program. Direct sales via door-to-door outreach will also be evaluated for potential inclusion as a future marketing channel.

## OUTDOOR LIGHTING MODERNIZATION PROGRAM

The primary goal for this program is to incentivize customers to switch from older, less efficient High intensity discharge (HID) technology to LED technology. This will lower electrical energy consumption for street and area lighting. The program will be offered in 2021-2023 allowing for a ramp-up period in 2021 with 25% of forecasted participation and then 37.5% in both 2022 and 2023.

The Outdoor Lighting Modernization Program encourages the market transition of Duke Energy Indiana owned street and area lighting to a more efficient Light-emitting diode (LED) lighting technology. Currently, only 5% of our Indiana lights (including streetlights and area lights) are LED as compared to 28% of US streets and roadways. Duke Energy Indiana's existing outdoor lighting customers are on the following tariffed rates:

- SL – Streetlight Service
- UOLS – Unmetered OL Electric Service
- MOLS – Metered OL Electric Service
- OL-E – Outdoor Lighting Service Agreement

Most existing outdoor lighting customers currently have Mercury Vapor (MV), Metal Halide (MH), or High Pressure Sodium (HPS or Sodium Vapor) fixtures. Upon complete fixture failure, the Company changes out MV, MH, and/or HPS fixtures to HPS. Customers may opt to upgrade to LED service under  Rider 42, Rate LED Unmetered Outdoor Lighting Service or under Rate OL-E Outdoor Lighting Service Agreement. Under this program, these customers will be offered an incentive to switch to Rider 42 with a per-fixture incentive based on wattage.

Generally, LED outdoor lighting products are preferred by customers because they offer significantly reduced energy use, exhibit longer lifetimes, do not contain mercury, and provide a high color quality which provides better illumination.

Rider 42 includes prescriptive rates for LEDs, so it provides rate clarity for customers. There are no upfront costs to the customer unless the lighting installation exceeds the Company's standards, as described in the Rider 42 Tariff. Customers can opt for standard or decorative fixtures. If a customer has a decorative pole and converts to a decorative LED, the customer may need to change out the pole as well. Customers can choose from a wide selection of LED decorative fixtures as replacements for the currently installed fixtures. The rate impact will depend upon the LED fixtures selected by customers. If it is too cost prohibitive, the customer can choose not to upgrade. Pole prices are also clearly stated in the Rider 42 tariff.

Customers with company owned lights will be contacted regarding their eligibility to participate in this program. The customer will receive an engineering estimate prior to accepting the contract outlining the estimated costs. Once the customer has accepted the proposal with selections made as to fixture type and pole replacement, if applicable, the project will be submitted for completion. After verification of the installation, we will pay customers directly a per fixture incentive based on wattage of what is being replaced.

The marketing strategy for this program will use internal marketing resources for this program and communications also via our community relations and account managers. A dedicated 1-800 number will be established as well as a comprehensive marketing plan once program approval has been received.

## 3. DEMAND RESPONSE PROGRAMS

In addition to the programs approved in Cause 43955 – DSM8, Duke Energy Indiana also offers the following Demand Response programs under its Rider 70 and other special contracts:

### POWERSHARE® CALLOPTION

***Program:*** PowerShare® CallOption is a non-residential demand response program. The program has components for customers to respond with load curtailment for both emergency and economic conditions and is marketed under the name PowerShare® CallOption. Customers receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated events triggered by capacity problems. Economic events are triggered on a day-ahead notification based on projections of next day market prices. Customers may "buy through" an economic event by paying the posted hourly price for the day of the event. Emergency events are triggered by MISO and provide customers notification that requires a response within 6 hours. There is no ability to buy through for emergency events.

**Eligibility.** Available to Customers served under Rates LLF and HLF that can provide at least 100 kW of load curtailment. Customers without load profile metering (less than

500 kW in maximum annual 30-minute demand) must pay the incremental cost of metering. Customers must enter into a service agreement.

**Customer Incentive.** Program participants will receive capacity credits (premiums) for loads they agree to curtail during program events. The amount of the capacity credit will depend on the offer and level of participation selected by the customer as well as the amount of load response. For actual energy curtailed during an economic event, CallOption customers will receive energy credits (event incentives). The amount of the event incentives will depend on the energy curtailed during the event and the established strike price.

## SPECIAL CURTAILMENT CONTRACTS

Duke Energy Indiana has contracted with several of its industrial customers to reduce their demand for electricity during times of peak system demand. Currently, two contracts are in effect. These contracts allow Duke Energy Indiana to provide "as available" or "non-firm" service to those customers. Some of these contracts date back to the late 1980s and early 1990s. By the terms of these contracts, Duke Energy Indiana can interrupt those customers at times of system peak, high marginal prices, or during times of system emergencies.

These interruptible contracts contain "buy-through" features except during times of system emergency. The Company currently expects and plans for a 185 MW reduction in the load forecasts for this "as available" load. This is projected to remain available and under contract over the forecast horizon, although there is a risk that customers will not renew the interruptible provisions of their contracts when they expire.

## D. PROJECTED IMPACTS

Duke Energy Indiana, through its DSM Oversight Board (OSB), hired a third-party consulting firm to conduct a market potential study (MPS) for EE and DR programs over a 25-year time horizon. The MPS energy savings and costs were extrapolated for five additional years in order to provide a 20 year EE forecast for the IRP. The MPS formed the basis of the projected impacts from EE and demand response programs. In preparing the projected impact options available for selection in this IRP, the Company 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 by the IRP models. The Energy Efficiency bundles were modeled based on the currently approved DSM portfolio and two of the four 2021 Duke Energy Indiana MPS scenarios: the Expanded Measure List and the Expanded Measure List with Avoided Cost Sensitivity. These two scenarios were selected as the basis for the bundles in collaboration with the OSB due to having the lowest levelized cost per MWh for EE savings.

The annual energy savings estimates were provided by either the currently approved EE Portfolio (2021-2023) or the Market Potential Study (2024-2040). The annual megawatt-hours and costs for the bundles were used to calculate a levelized cost in $/MWh for each bundle. These levelized costs were adjusted to cover the costs of program overhead and utility incentives and then credited with the savings associated with avoided Transmission and Distribution costs. These adjustments made the final costs lower than the base levelized costs associated with each bundle. The levelized cost and hourly MWh for each bundle were loaded into the IRP models as discrete resource options for selection. This process enabled the EE programs to compete for selection against traditional generating resources to serve projected customer load.

## 2021-2023

For the first 3-year bundle (2021-2023), the IRP model was required to select the entire bundle that reflects the savings and costs associated with the currently approved DSM portfolio. This first bundle also contained the Income Qualified programs for the 2024-2040 period as these programs are often higher cost than others, thus, they were represented in this "must-select" bundle to prevent disadvantaging future EE programs based on the higher average cost of Income Qualified programs.

## 2024-2040

For all subsequent bundles, the recommended EE portfolio includes only the bundles selected by the IRP model. In each time period of the IRP, the model had the option to select the bundles based on the "expanded measure" scenario, the "expanded measure list + higher avoided cost" scenario, or no energy efficiency bundle. In all cases, the IRP model selected a bundle covering every time period in all IRP scenarios.

In order to provide the model with increased granularity in the near term, a set of bundles was analyzed with a duration of three years for the periods 2021-23 and 2024-26. These three-year periods also correspond with the current and upcoming DSM Plan filings. In order to reduce the computational burden on the IRP models, the next three sets of bundles were analyzed with a duration of 8 years for the periods 2027-34, 2035-2042 and 2043-2050.

Bundles beyond the MPS were defined by extrapolation for the final 5 years.  The bundles in the 2040's were used to minimize potential end effects.

Table D-1 below provides the potential projected annual Gross MWh impacts (includes Free Riders) from the EE programs in the Moderate Transition Portfolio, as selected by the IRP model.

## TABLE D-1
## MWH LOAD IMPACTS OF EE PROGRAMS

| Year | Cumulative Gross MWh Impacts at Generation |
|---|---|
| 2021 | 207,105 |
| 2022 | 422,052 |
| 2023 | 635,299 |
| 2024 | 867,338 |
| 2025 | 1,086,538 |
| 2026 | 1,293,068 |
| 2027 | 1,492,079 |
| 2028 | 1,687,707 |
| 2029 | 1,878,286 |
| 2030 | 2,064,310 |
| 2031 | 2,245,672 |
| 2032 | 2,422,911 |
| 2033 | 2,599,691 |
| 2034 | 2,777,092 |
| 2035 | 2,956,222 |
| 2036 | 3,137,449 |
| 2037 | 3,319,517 |
| 2038 | 3,503,094 |
| 2039 | 3,688,187 |
| 2040 | 3,875,337 |

Table D-2 provides the MW impacts from the special contracts and demand response programs. The MW impacts from the selected EE programs are included in the Load Forecasting section.

## TABLE D-2
## MW LOAD IMPACTS OF DR PROGRAMS[1]

| | Demand Response Program Load Impacts MW | | | |
|---|---|---|---|---|
| Year | PowerShare | Power Manager | Interruptible | Total DR |
| 2021 | 262 | 35 | 200 | 497 |
| 2022 | 272 | 35 | 200 | 507 |
| 2023 | 276 | 36 | 200 | 512 |
| 2024 | 333 | 74 | 200 | 607 |
| 2025 | 338 | 75 | 200 | 613 |
| 2026 | 338 | 76 | 200 | 613 |
| 2027 | 338 | 76 | 200 | 613 |
| 2028 | 338 | 76 | 200 | 613 |
| 2029 | 338 | 76 | 200 | 613 |
| 2030 | 338 | 76 | 200 | 613 |
| 2031 | 338 | 76 | 200 | 613 |
| 2032 | 338 | 76 | 200 | 613 |
| 2033 | 338 | 76 | 200 | 613 |
| 2034 | 338 | 76 | 200 | 613 |
| 2035 | 338 | 76 | 200 | 613 |
| 2036 | 338 | 76 | 200 | 613 |
| 2037 | 338 | 76 | 200 | 613 |
| 2038 | 338 | 76 | 200 | 613 |
| 2039 | 338 | 76 | 200 | 613 |
| 2040 | 338 | 76 | 200 | 613 |

[1] DR MWs for Power Manager includes MWs from Power Manager, Power Manager Water Heaters, Power Manager for Apartments, and Power Manager for Business.

## E. EXISTING ENERGY EFFICIENCY PROGRAMS, HISTORICAL PERFORMANCE

Duke Energy Indiana has been aggressive in the planning and implementation of energy efficiency programs. The forecast of loads provided in Chapter 3 incorporates the effects of these historical impacts in the baseline forecast, subject to anticipated "roll off" into prevailing codes and standards.

## F. INTEGRATED VOLT-VAR CONTROL (IVVC)

Duke Energy Indiana is implementing grid modernization throughout the enterprise with a vision of creating a sustainable energy future for our customers and our business by being a leader of innovative approaches that will modernize the grid.

Duke Energy Indiana is implementing an IVVC project that will better manage the application and operation of voltage regulators (the Volt) and capacitors (the VAR) on the Duke Energy Indiana distribution system. In general, the project optimizes the operation of these devices, resulting in a reduction and "flattening" of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by automating the substation level voltage regulation devices and capacitors, distribution line capacitors, and distribution line voltage regulators, while integrating them into a single control system. The control system continuously monitors and operates the voltage regulators and capacitors in near real time, coordinated control to maintain the optimized "flat" voltage profile. Once the system is operating with a flat voltage profile across an entire circuit, the net result is a reduction of system loading.

The deployment of an IVVC program for Duke Energy Indiana is anticipated to take approximately seven years, and began in 2019. This IVVC program is projected to reduce future distribution-only system peak needs by approximately 0.09% in 2021, 0.13% in 2022, and 0.64% in 2023 and beyond. Although the subject of grid modernization is very broad, only the supply and demand impacts of the IVVC program is included in the IRP process where the IVVC program is modeled as a resource.

The cadence of IVVC assets going into service and providing benefits have been adjusted based on historical actuals and is therefore less than the original projections. However, many of the IVVC deployments not completed under TDSIC 1.0 are expected to carry-over into TDSIC 2.0, and result in load reductions equivalent to the original projections of 0.7%. In addition, there is a proposed expansion of the IVVC program in TDSIC 2.0 that will provide further load reductions. The ability to deploy this plan under TDSIC 2.0 depends on regulatory actions.

## G. DUKE ENERGY INDIANA ENERGY EFFICIENCY DATA

### 1. AVOIDED COST FOR EE SCREENING

The avoided costs used in screening the EE and DR programs in the Market Potential Study to determine the Economic Potential were based on information in the Portfolio Program filing (Cause No. 43955 – DSM8) approved by the Commission on December 29, 2020. The Company considers this information to be a trade secret, confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order. Please contact Beth Heneghan at (317) 838-1254 for more information.

## 2. EE PROGRAM DATA

EE and DR Program data is voluminous, and will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours. Please contact Beth Heneghan at (317) 838-1254 for more information.

## 4. BENEFIT/COST TEST COMPONENTS AND EQUATIONS

| BENEFIT/COST TEST MATRIX | | | | | |
|---|---|---|---|---|---|
| Benefits: | Participant Test | Utility Test | Ratepayer Impact Test | Total Resource Test | Societal Test |
| Customer Electric Bill Decrease | X | | | | |
| Customer Non-electric Bill Decrease | X | | | | |
| Customer O&M and Other Cost Decrease | X | | | X | X |
| Customer Income Tax Decrease | X | | | X | |
| Customer Investment Decrease | X | | | X | X |
| Customer Rebates Received | X | | | | |
| Utility Revenue Increase | | | X | | |
| Utility Electric Production Cost Decrease | | X | X | X | X |
| Utility Generation Capacity Credit | | X | X | X | X |
| Utility Transmission Capacity Credit | | X | X | X | X |
| Utility Distribution Capacity Credit | | X | X | X | X |
| Utility Administrative Cost Decrease | | X | X | X | X |
| Utility Cap. Administrative Cost Decrease | | X | X | X | X |
| Non-electric Acquisition Cost Decrease | | | | X | X |

| BENEFIT/COST TEST MATRIX | | | | | |
|---|---|---|---|---|---|
| Benefits: | Participant Test | Utility Test | Ratepayer Impact Test | Total Resource Test | Societal Test |
| Utility Sales Tax Cost Decrease | | X | X | X | |
| Costs: | | | | | |
| Customer Electric Bill Increase | X | | | | |
| Customer Non-electric Bill Increase | X | | | X | |
| Customer O&M and Other Cost Increase | X | | | X | X |
| Customer Income Tax Increase | X | | | X | |
| Customer Capital Investment Increase | X | | | X | X |
| Utility Revenue Decrease | | | X | | |
| Utility Electric Production Cost Increase | | X | X | X | X |
| Utility Generation Capacity Debit | | X | X | X | X |
| Utility Transmission Capacity Debit | | X | X | X | X |
| Utility Distribution Capacity Debit | | X | X | X | X |
| Utility Rebates Paid | | X | X | | |
| Utility Administrative Cost Increase | | X | X | X | X |
| Utility Cap. Administrative Cost Increase | | X | X | X | X |

| BENEFIT/COST TEST MATRIX | | | | | |
|---|---|---|---|---|---|
| Benefits: | Participant Test | Utility Test | Ratepayer Impact Test | Total Resource Test | Societal Test |
| Non-electric Acquisition Cost Increase | | | | X | X |
| Utility Sales Tax Cost Increase | | X | X | X | |

Benefit/Cost Ratio = Total Benefits/Total Costs

TABLE D-3
PROJECTED PROGRAM EXPENDITURES

## DUKE ENERGY INDIANA 2021 – 2023 ENERGY EFFIIENCY PROGRAMS*

| RESIDENTIAL | | 2021-2023 |
|---|---|---|
| Agency Assistance Portal | $ | 19,978 |
| Energy Efficiency Education Program for Schools | $ | 2,574,748 |
| Low Income Neighborhood | $ | 2,024,131 |
| Low Income Weatherization | $ | 4,782,194 |
| Multi-Family EE Products & Services | $ | 6,190,270 |
| My Home Energy Report | $ | 8,397,062 |
| Residential Energy Assessments | $ | 4,488,821 |
| Smart $aver® Residential | $ | 14,041,902 |
| Power Manager | $ | 8,291,145 |
| **Total Residential** | **$** | **50,810,251** |

| NON-RESIDENTIAL | | |
|---|---|---|
| Public Efficiency Streetlighting | $ | 2,173,924 |
| Smart $aver® Non-Residential | $ | 40,644,456 |
| Power Manager® for Business | $ | 5,498,476 |
| Small Business Energy Saver | $ | 10,927,521 |
| **Total Non-Residential** | **$** | **59,244,376** |
| | | |
| Market Potential Study | | |
| **Total Non-Residential** | **$** | **275,000** |
| | | |
| Grand Total 2011-2023 Portfolio | **$** | **110,329,627** |

* Totals may not foot due to rounding

DUKE ENERGY INDIANA

# APPENDIX E

## TRANSMISSION PLANNING

APPENDIX E

# TRANSMISSION PLANNING

## 1. TRANSMISSION EXECUTIVE SUMMARY

### A. SYSTEM DESCRIPTION

The Duke Energy Indiana bulk transmission system is comprised of the 345 kilovolt (kV), 230 kV, and 138 kV systems. The Duke Energy Indiana transmission system serves primarily to deliver bulk power into and/or across the Duke Energy Indiana service area. This bulk power is distributed to numerous substations that supply lower voltage sub-transmission systems and distribution circuits, or directly to large customer loads. Because of the numerous interconnections Duke Energy Indiana has with neighboring local balancing areas, the Duke Energy Indiana 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.

As of December 2020, Duke Energy Indiana's wholly and jointly owned share of bulk transmission included approximately 855 circuit miles of 345 kV lines, 779 circuit miles of 230 kV lines, and 1478 circuit miles of 138 kV lines. Duke Energy Indiana, Indiana Municipal Power Agency (IMPA), and Wabash Valley Power Alliance (WVPA) own the Joint Transmission System (JTS) in Indiana. The three co-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.

## B. ELECTRIC TRANSMISSION FORECAST

As a member of the Midcontinent Independent System Operation (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.

# 2. ELECTRIC TRANSMISSION FORECAST

## A. GENERAL DESCRIPTION

The Duke Energy Indiana bulk transmission system is comprised of 138 kV, 230 kV, and 345 kV systems. The 345 kV system distributes power from Duke Energy Indiana's large generating units, and interconnects the Duke Energy Indiana system with other systems. The 345 kV system is connected to the 138 kV and 230 kV systems through large transformers at a number of substations across the system. 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. This power is distributed to substations, which supply lower voltage sub-transmission systems and distribution circuits, or directly to a number of large customer loads.

## B. TRANSMISSION AND DISTRIBUTION PLANNING PROCESS

Transmission and distribution (T&D) planning is a complex process which 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 make sure 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 is 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 FERC Form 715 Part 4. The Company adheres to any applicable NERC and RFC Reliability Standards, and to its own detailed planning criteria, which are shown in the following paragraphs. Violations of these criteria would require expansion of 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.

## VOLTAGE

Bus voltages are screened using the Transmission System Voltage Limits 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.

## TRANSMISSION SYSTEM VOLTAGE LIMITS

| Nominal Voltage (kV) | Normal Voltage Limits | | Emergency Voltage Limits | |
|---|---|---|---|---|
| | Minimum | Maximum | Minimum | Maximum |
| 345 | 95% | 105% | 90% | 105% |
| 230 | 95% | 107% | 90% | 107% |
| 138 | 95% | 105% | 90% | 105% |

## THERMAL

The following guidelines shall be used to ensure acceptable thermal loadings:

a) In normal conditions, no facility should exceed its continuous thermal loading capability.

b) 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 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 capable of interrupting the maximum fault current duty imposed on the circuit breaker.

## SINGLE CONTINGENCIES

The thermal and voltage limits should not be violated for either normal operations or under the loss of:

a) A single transmission circuit
b) A single transformer
c) A single generating unit
d) 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.

## C. 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 ten years if the planned transmission system expansions are completed as currently scheduled. See Part F in this Appendix for 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, RFC 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.

## D. 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.

## E. TRANSMISSION EXPANSION PLANS

The transmission system expansion plans for the Duke Energy Indiana system are developed for the purpose of meeting 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 MW and MVAR 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 development of the regional transmission plan. MTEP 21 assessed the Duke Energy Indiana transmission system for the period 2021 through 2031 with simulations for years 2021, 2022, 2023, 2026 and 2031. 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 and increased operating expenses from redispatching network resources or other operational actions.

## F. TRANSMISSION PROJECT DESCRIPTIONS

The following planned transmission projects include new substation transformers, transmission capacitors, transmission circuits, and upgrades of existing circuits and substations.

The Mitchell Lehigh project provides a networked feed to the expanding Lehigh customer. The networked feed will consist of a new 138 kV substation with an auto-sectionalizing scheme, an approximately 4 mile line from the new substation going northwest to the 138 kV line, and an approximately 3.5 mile line from the new substation going southeast to the 138 kV line. The project will be connected to the Bedford to Gallagher 138 kV line.

The Fairbanks Solar project consists of a new three breaker 345 kV ring bus to connect a new 250 MW solar farm to the power system. The ring bus will connect approximately 13 miles south of the Dresser substation on the Dresser to HE Merom 345 kV line. In addition to connecting the solar farm, this project will reduce 345 kV line exposure.

The Hardy Hills project is a new three breaker self-build 230 kV ring bus to connect a new 195 MW solar farm to the power system. The ring bus will connect approximately 14.5 miles from the New London station on the New London to Frankfort 230 kV line. Duke Energy Indiana will provide oversight of the new substation construction as well as the transmission line work necessary to connect the substation to the electrical grid. In addition to connecting the solar farm, this project will reduce 230 kV line exposure.

The NW Tap to Lafayette Cincinnati Street 138 kV line rebuild will rebuild approximately 11.2 miles of 138 kV line with larger sized conductor, including conductor that is double circuited with the NW Tap to Lafayette Cincinnati Street line. This project will allow for connection of a customer, expansion in the Lafayette service area, and lower loadings on lines for contingency outages.

The Lafayette South to Lafayette Shadeland 138 kV line rebuild will rebuild approximately 3.4 miles of 138 kV line with larger sized conductor. This project will allow for connection of a customer, expansion in the Lafayette service area, and lower loadings on lines for contingency outages.

## G. 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.

## H. SHORT TERM IMPLEMENTATION PLAN - PLANNED NEW TRANSMISSION FACILITIES

### DESCRIPTION OF PROJECTS

See the tables below for status of previous projects reported as well as a current projects listing. More detailed descriptions of the current projects can be found above in Part G of this Appendix.

### CRITERIA AND OBJECTIVES FOR MONITORING SUCCESS

Milestones and criteria used to monitor the transmission facilities projects are typical of construction projects and measured on the following factors:


- **Comparison of the actual completion date to the targeted completion date**
- **Comparison of the actual cost to the budgeted cost**

### ANTICIPATED TIME FRAME AND ESTIMATED COSTS

The cash flows associated with the major new transmission facility projects planned are shown below.

## STATUS UPDATES AND CHANGES FROM PREVIOUS REPORT DUKE ENERGY INDIANA TRANSMISSION PROJECTS

| | | | | CASH FLOWS ($000)* | | |
|---|---|---|---|---|---|---|
| PROJECT NAME | MILES or MVA | kV | PROGRESS/ COMPLETION DATE | 2019 | 2020 | 2021 |
| Sugar Creek to Ameren Kansas (Note 1) | 1.3 | 345 | 6/5/2019 Duke Energy Indiana Portion Completed 6/21/2019 Full Project Completed 12/14/2020 | $9,459 | $336 | ($2) |
| Laf SE Conc Rd. Jct 138kV Line (Note 1 and Note 2) | 1.5 | 138 | 1/15/2020 Completed 11/23/2020 | $1,688 | $1,372 | $150 |
| Speed to Jeffersonville 138 kV line (Note 1 and Note 2) | 2.5 | 138 | 3/26/2019 Completed 10/13/2021 | $2,006 | $1,201 | $6,118 |

## CURRENT DUKE ENERGY INDIANA MAJOR TRANSMISSION PROJECTS

| | | | | CASH FLOWS ($000)* | | |
|---|---|---|---|---|---|---|
| PROJECT NAME | MILES or MVA | kV | PROGRESS/ COMPLETION DATE | 2021 | 2022 | 2023 |
| Mitchell Lehigh (Note 1) | 8 | 138 | 3/31/2023 | $9,586 | $3,209 | $1,262 |
| Fairbanks Solar Switching Station (Note 3) | - | 345 | 5/30/2023 | $493 | $11,173 | $2,462 |
| Hardy Hills Switching Station (Note 4) | - | 230 | 9/07/2022 | $276 | $1,859 | $31 |
| NW Tap to Lafayette Cincinnati St. Rebuild | 11.2 | 138 | 12/31/2023 | $150 | $10,000 | $34,000 |
| Lafayette South to Lafayette Shadeland Rebuild | 3.4 | 138 | 12/31/2023 | $300 | $3,357 | $3,657 |

*Excluding AFUDC

## ANTICIPATED PROJECT MILESTONES

The completion of these projects, by their planned in-service dates and costs, are the project milestones. Individual project specific notes from the above tables are given as follows:

**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 is partially funded by WVPA as part of their obligations as joint owner of the Duke Energy Indiana transmission system.

**NOTE 3** – Project to be reimbursed by developer.

**NOTE 4 –** 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.

# I. TRANSMISSION UPGRADES NEEDED FOR INTERCONNECTION OF INCREMENTAL RESOURCES IDENTIFIED IN THE PREFERRED RESOURCE PLAN

## MISO GENERATOR INTERCONNECTION PROCESS

To allow for interconnection of each incremental generator reflected in the Duke Energy Indiana Preferred Plan to serve customer demand in the Duke Energy Indiana service territory, one of the following must occur:

1. Duke Energy Indiana must enter into a Purchase Power Agreement with a generator that has, or is in process of receiving a Generator Interconnection Agreement through MISO's Generator Interconnection Process
2. Duke Energy Indiana must purchase a generator that has, or is in process of receiving a Generator Interconnection Agreement through MISO's Generator Interconnection Process
3. Duke Energy Indiana must submit a Generator Interconnection Application and enter MISO's next Definitive Planning Phase Study determining the necessary transmission network upgrades needed to facilitate interconnection, and move forward in the process to a Generator Interconnection Agreement
4. If applicable where a replacement generator is replacing retired generation at the similar point of interconnection, enter MISO's Generator Replacement Process for study and receipt of a Generator Interconnection Agreement for the Replacement Generation.

MISO's generator interconnection process and associated Definitive Planning Phase 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 associated with the generator interconnection as the studies progress.

The results of the 2019 MISO Definitive Planning Phase Study reflected an average cost of $0.167/Watt for network upgrades needed to facilitate interconnection of the generators in Indiana (Zone 6) requesting interconnection.

## J. TRANSMISSION NETWORK UPGRADE COST DETERMINANTS ASSOCIATED WITH INTERCONNECTIONS OF INCREMENTAL GENERATION IN DUKE ENERGY INDIANA

Location, MW of interconnection requested, resource/load characteristics, and number of queued requests for the given cluster 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 in future years could be significant. In addition to risks associated with costs, 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 will also be dependent on any affected system network upgrades that are required.

## K. LONG TERM TRANSMISSION PLANNING

Duke Energy Indiana participates in MISO reviews and studies regarding long term transmission planning. In addition to the annual MISO Transmission Expansion Plan (MTEP) process, MISO is conducting Long Range Transmission Planning (LRTP) studies using analysis from its MISO Futures Report. The Futures Reports contains an analysis of three scenarios (or futures) to provide insights into future transmission system needs, focusing on several critical aspects of planning and managing the grid including reliability, resiliency, system diversity, economics, and challenges with operating the grid with a changing resource mix, in particular as renewable energy increases on the MISO system. Another recent MISO study, the Renewable Integration Impact Assessment (RIIA), informs the LRTP and considers the impacts and challenges of increasing wind and solar energy on the MISO system. All of these processes and studies will work together to 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 from traditional dispatchable generating resources. Duke Energy Indiana remains fully engaged in MISO stakeholder processes on these critical issues.


# APPENDIX F

## ENVIRONMENTAL COMPLIANCE

APPENDIX F

# ENVIRONMENTAL COMPLIANCE

## A. INTRODUCTION

The environmental compliance planning process develops an integrated resource / compliance plan meeting future resource needs and environmental requirements in a reliable and economic manner. Compliance planning associated with existing laws and regulations is discussed in Section B. Risks associated with anticipated and potential changes to environmental regulations are discussed in Section C.

## B. COMPLIANCE PLANNING – EXISTING LAWS AND REGULATIONS

### 1. OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

a. **Attainment Designations for Indiana:** On October 1, 2015, EPA finalized a rule lowering the ozone standard from 75 to 70 ppb. The EPA finalized attainment designations in 2017, based on actual 2014-2016 ozone air quality data. EPA designated several Indiana counties as non-attainment including Lake and Porter Counties (Chicago area), and Clark and Floyd Counties (Louisville area). These counties were all classified as "marginal" non-attainment, which did not require Indiana to adopt any further emission controls at facilities in the affected counties provided that the areas achieve attainment during the first planning period (by 2021). The Gallagher

Station is located in the Louisville non-attainment area, but it ceased operation on June 1, 2021. On December 31, 2020, EPA completed its mandatory five-year NAAQS review and announced that it would retain the 70-ppb standard. However, on October 29, 2021, EPA announced that it will reconsider its 2020 decision and it expects to complete its review and issue any final action on a revised NAAQS by the end of 2023. Duke Energy Indiana cannot predict whether any additional restrictions will result from this reconsideration.

b. **Interstate Transport – Ozone "Good Neighbor" Plans:** In addition to requiring states to develop regulations to assure attainment of NAAQS within their own borders, the Clean Air Act (CAA) also requires states to develop plans to identify and reduce any significant impact on non-attainment areas in downwind states (the "Good Neighbor" State Implementation Plan (SIP) requirements). The ozone season requirements of the 2011 Cross State Air Pollution Rule (CSAPR) (effective in 2015) and the 2016 CSAPR Update Rule (effective in 2017) were promulgated as Federal Implementation Plans (FIPs) by EPA in response to findings that states within a 22-state region had not adopted adequate Good Neighbor SIPs to address significant impacts on downwind non-attainment areas relative to the 2008 ozone NAAQS. On April 30, 2021, EPA issued a "Revised CSAPR Update Rule" which created a new and smaller trading region for Indiana and eleven other states and significantly reduced the ozone season cap. To date, Duke Energy has managed compliance with the allowance-based requirements of the Revised

CSAPR Update Rule by additional emissions reductions achieved through enhanced performance of the Selective Catalytic Reduction (SCR) systems installed at Cayuga and Gibson Stations.

Relative to the 2015 ozone standard, Indiana filed a Good Neighbor SIP on November 2, 2018, which concluded that emission sources (including EGUs) within Indiana do not have a significant impact on downwind non-attainment areas. The SIP submitted by Indiana for EPA approval would not require any additional ozone season actions at Duke Energy facilities beyond rules adopted to implement the CSAPR provisions. EPA has not made a determination whether to approve or disapprove Indiana's plan. If Indiana's SIP is not approved, EPA may either remand the plan to Indiana for additional rulemaking or it may issue a FIP imposing additional requirements.

c. **Section 126 Petitions:** Under Section 126 of the Clean Air Act, states can petition EPA for a finding that upwind sources are violating the good neighbor provision. If EPA makes such a finding, the source(s) must cease operation or comply with emission limitations established by EPA. Duke Energy was the subject of petitions from the states of Maryland and New York alleging that the emissions from numerous sources, including Duke Energy coal-fired units in Indiana, are significantly contributing to downwind violations of the 2008 ozone NAAQS. The New York petition also claimed impacts on attainment of the 2015 ozone NAAQS. As a remedy, both states asked EPA to impose short-term ozone season NOx emissions limits that would be in addition to the mass-based requirements under the CSAPR program. Although EPA denied these petitions, the petitions were litigated and subsequently remanded back to EPA for further review. To date, EPA has not announced any action to address the remands.

## 2. SULFUR DIOXIDE AMBIENT AIR QUALITY STANDARD

On June 22, 2010, EPA established a 75 ppb 1-hour $SO_2$ NAAQS and revoked the annual and 24-hour $SO_2$ standards. EPA finalized initial nonattainment area designations in July 2013 and completed its designation of all areas in Indiana as non-attainment or attainment/unclassifiable in December 2020. All areas of Indiana where Duke Energy Indiana generating facilities are located have been classified as attainment/unclassifiable for the $SO_2$ NAAQS, and no further $SO_2$ controls or restrictions are anticipated at these facilities as a result of the $SO_2$ NAAQS.

## 3. MATS

On June 29, 2015, the Supreme Court found that EPA should have considered costs as part of its determination of whether the regulation of hazardous air pollutants (HAPs) from power plants was appropriate and necessary, and remanded the case to the D.C. Circuit Court for further proceedings. Despite the Supreme Court's decision, the MATS rule remains in effect pending further action by the D.C. Circuit, meaning that all affected sources must continue to meet the rule requirements. Duke Energy Indiana cannot predict the outcome of the court proceedings or how it might affect the MATS requirements. Duke Energy Indiana's coal fired units are complying with all requirements of the MATS rule.

On May 22, 2020, EPA published a final rule which concluded that it is not "appropriate and necessary" to regulate power plant HAP emissions. However, EPA declined to rescind the 2012 MATS rule. In addition, EPA issued the results of its statutorily required Residual Risk and Technology Review (RTR) and determined that no changes to the MATS emission standards were needed. On May 22, 2020, Westmoreland Mining Holdings, LLC filed a petition for review challenging the final rule in the D.C. Circuit Court. On August 3, 2021, in accordance with President Biden's Executive Order 13990, EPA submitted to the Office of Management and Budget for interagency review a proposed rule to suspend, revise, or rescind the 2020 appropriate and necessary finding.

## 4. STEAM ELECTRIC EFFLUENT LIMITATION GUIDELINES

EPA signed the final revisions to the Steam Electric Effluent Limitations Guidelines (ELG) on September 30, 2015 and a subsequent Reconsideration Rule on August 31, 2020. The new limitations are incorporated into a station's National Pollutant Discharge Elimination System (NPDES) permit upon renewal. The rule requires the new limitations for Flue Gas Desulphurization (FGD) and Bottom Ash Transport Water (BATW) to apply based on a date determined by the permitting authority that is as soon as possible beginning October 13. 2021 but no later than December 31, 2025.

Duke Energy Indiana has installed wastewater treatment that is believed to be compliant with the rule, as appropriate for a specific facility, including dry fly and bottom ash systems, and plant process wastewater management systems. The ELG Reconsideration Rule also establishes a subcategory for units that cease combustion of coal by December 31, 2028. This subcategory accounts for factors such as age of the facility and costs of achieving effluent reduction. Duke Energy Indiana submitted the required "Notice of Planned Participation" for the Cayuga Generating Station on October 7, 2021.

Challenges to the 2015 and 2020 ELG Rules are separately consolidated in the Fourth and Fifth Circuit United States Court of Appeals with a decision undetermined and proceedings stayed at this time. For coal combustion residuals (CCR) leachate, the limits were vacated and remanded to the EPA for further consideration on April 12, 2019 by the Fifth Circuit United States Court of Appeals. The EPA published a notice in the Federal Register on August 3, 2021 that it would promulgate another ELG Rule to "determine whether more stringent limitations and standards are appropriate", specifically noting FGD (using membrane treatment systems) and BATW waste streams. EPA intends to issue a proposed rule in Fall 2022; however the 2015 and 2020 ELG Rules will remain effective.

## 5. CLEAN WATER ACT SECTION 316(a) AND 316(b)

The final 316(b) rule revision was published in the Federal Register on August 15, 2014, with an effective date of October 14, 2014. The 316(b) Rule establishes aquatic protection requirements at existing facilities and new on-site generation that withdraw 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters, utilizes at least 25% of the water withdrawn for cooling purposes, and has a NPDES discharge permit.

The rule requires facilities with a NPDES permit expiring after July 14, 2018 to submit all necessary 316(b) reports with the renewal application. For facilities with a NPDES permit expiring prior to July 14, 2018 or are in the renewal process, the state permitting agency is allowed to establish an alternate submittal schedule. As required by the 316(b) Rule, Duke Energy Indiana submitted study reports for Gibson and Gallagher during 2019 and Cayuga during 2020. Any required intake modification would be anticipated to occur during the 2022 to 2025 timeframe, depending on the NPDES compliance schedule developed by IDEM. At this time, Duke Energy Indiana believes that its facilities are compliant with the 316(b) Rule; however installation of new fish friendly traveling screens ("modified Ristroph") may be required at Cayuga if the existing cooling water system configuration continues to operate after December 31, 2028.

## C. ENVIRONMENTAL RISK/REGULATORY IMPACTS

Several environmental risks/regulatory changes can affect Duke Energy Indiana in the future. The Company closely monitors these changes and develops responses when necessary.

### 1. PARTICULATE MATTER NAAQS ($PM_{2.5}$)

On December 14, 2012, EPA finalized a rule lowering the annual PM2.5 standard from 15 to 12 ug/m3 and retaining the 35 ug/m3 daily PM2.5 standard. The EPA finalized area designations for the standard in early 2015. No areas in the Company's service territory were designated as nonattainment areas for the revised standard. To date, neither the annual nor the daily PM2.5 standard has directly driven emission reduction requirements at Duke Energy Indiana facilities. The reduction in $SO_2$ and NOx emissions to address the PM2.5 standards has been achieved through CAIR and CSAPR, each developed to address interstate transport. At this time, there is no indication that the revised PM2.5 standard will result in EPA developing a new PM2.5 interstate transport rule. On December 18, 2020, EPA completed its mandatory five-year review and announced that it would retain the 12 ugm standard. However, on June 10, 2021, EPA announced that it will reconsider its 2020 decision. It is anticipated that EPA could issue a proposed rule in summer of 2022 and a final rule in the spring of 2023. Duke Energy Indiana cannot predict whether any additional restrictions will result from this reconsideration.

The annual $SO_2$ and NOx allowance-based limits included in the 2011 Cross State Air Pollution Rule (CSAPR) were imposed by the EPA under a Federal Implementation Plan (FIP) based on EPA's determination that states within a 22-state region, including Indiana, had not adopted adequate regulations to address significant impacts on downwind PM2.5 non-attainment areas in other states. Emissions of $SO_2$ and NOx contribute to PM2.5 formation through atmospheric chemical reactions that produce aerosol particles. The emission controls installed on Duke Energy fossil-fired facilities in Indiana, including the flue gas desulfurization systems (FGD) and selective catalytic reduction (SCR) systems at Gibson and Cayuga Stations, are sufficient to maintain annual emissions of $SO_2$ and NOx well below the annual CSAPR allocations for Duke Energy Indiana for these pollutants.

## 2. COAL COMBUSTION RESIDUALS (CCRS)

On April 17, 2015 EPA published its final rule for the disposal of CCRs. The rule regulates CCRs as a non-hazardous waste under Subtitle D of the Resource Conservation Recovery Act (RCRA). This is the first federal regulation of CCRs. The effective date of the rule was October 19, 2015, starting with the obligation to comply with the operating requirements. Congress passed and the President signed the WIIN Act in 2016. Section 2301 of the Act amends Section 4005 of the Resource Conservation and Recovery Act (RCRA) to provide for state coal combustion residuals (CCR) permit programs. The law also provides EPA additional authorities including the authority to review and approve state CCR permit programs. Once approved, the state permit program operates "in lieu of" the federal CCR rule. Additional rulemaking by the EPA is anticipated, including development of a federal permit program, but a schedule has not been set. This rulemaking has the potential to affect how Duke Energy complies with the CCR rule.

The rule is applicable to all new and existing landfills and surface impoundments used to store or dispose of CCRs. In addition to surface impoundments that are actively receiving CCR, the rule applies to CCR surface impoundments no longer receiving CCRs if they contained CCRs and liquids on the effective date of the rule. The rule does not apply to inactive landfills that did not receive CCR after the effective date of the rule. The rule will result in the closure of all regulated surface impoundments used to store or dispose of CCRs and treat non-CCR wastewaters. The closure of surface impoundments lead to dry handling of fly ash and bottom ash and the need for additional landfill capacity. It has also resulted in a need for alternative wastewater treatment for the non-CCR wastewaters in smaller lined ponds. The regulatory deadlines that have factored into the closure of surface impoundments include non-compliance with structural integrity standards (April 2017), exceedance of ground water protection standards and later a requirement to close all unlined impoundments not already in closure (previously April 2018,updated to April 2021), or failure to demonstrate compliance with location restrictions (April 2019). Duke Energy Indiana filed with the IDEM in December 2016 closure plans to either close in place or excavate impoundments at all facilities. At this time IDEM has approved all the closure plans.

## 3. GREENHOUSE GAS REGULATION

In June 2019, EPA finalized the Affordable Clean Energy (ACE) rule to replace the previous Clean Power Plan. The ACE rule would require $CO_2$ emissions reductions from existing coal-fired electric generating units by requiring states to develop implementation plans based on efficiency improvements that can be adopted "inside the fence" at existing power plants. On January 19, 2021, the Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision vacating the ACE Rule and the repeal of the Clean Power Plan and remanding them to EPA for further proceedings. On February 12, 2021, EPA filed a motion with the D.C. Circuit asking the Court to vacate the ACE rule, but to stay the issuance of the mandate for the vacatur of the Clean Power Plan repeal until EPA can respond to the Court remand in a new rulemaking. On February 22, 2021, the D.C. Circuit granted this motion.

On August 3, 2015, EPA finalized a Greenhouse Gas New Source Performance Standards (NSPS) rule that established $CO_2$ emission standards for new, modified, and reconstructed coal fired and combined cycle power plants. This final rule would have prevented Duke Energy Indiana from developing any new coal-fired power plants that are not equipped with carbon capture and storage technology. On December 6, 2018, EPA proposed to revise the $CO_2$ emissions standards for new-modified, and reconstructed coal fired power plants. This proposal would replace the 2015 rule with one that requires new large coal units to meet an emission rate reflective of supercritical operation (1,900 lb. $CO_2$/MWhr). EPA has not finalized this action.

## D. ENVIRONMENTAL COMPLIANCE PLAN

The current modeling analysis primarily focused on compliance with the 316(b) rule requirements, and existing or future ELG rule revision compliance. For CCR and ELG compliance, conversion to dry ash handling and lined retention basin projects are already complete; ongoing future incremental landfill construction and closure costs (if needed) were included in the analysis dynamically. For 316(b) compliance, based on site-specific considerations, standard mesh and fish friendly screens and fish return systems were assumed. For ELG compliance, a bioreactor was included at Cayuga (though this cost was modeled as avoidable with retirement by 2028), and costs for a future ELG rule revision for Cayuga that assumed membrane treatment with encapsulation technology for FGD wastewater were modeled by 2033.

In summary, for purposes of this IRP, the suite of non-carbon related future environmental regulations and general requirements modeled included:

- CCR Rule, and ELG revisions
    - Ongoing future incremental landfill construction and closure costs
- ELG Rule
    - For Cayuga, a bioreactor by 2025 (modeled as avoidable with retirement by 2028), and membrane plus encapsulation treatment technology for FGD wastewater by 2033
    - For Gibson, though not governed by an NPDES permit, minor wastewater treatment system improvements were modeled by 2033 assuming some EPA "best professional judgement" applicability

- 316(b) Intake Structure Rule
    - For Cayuga, intake structure and traveling screen upgrade costs by 2027
    - Cooling tower installations were assumed to be mandated for coastal and estuarial units, but this assumption only impacted the development of fundamental forecast inputs as none of Duke Energy Indiana's assets meet these criteria. The unit compliance timeframes were based on each facility's NPDES permit renewal

The balance of all the assumptions for the compliance analysis were reviewed and updated where necessary to coincide with the other assumptions used for the development of this IRP.

## 1. MODELING ASSUMPTIONS

For this analysis, Duke Energy Indiana utilized a similar analytical modeling process to past compliance planning activities. Forecasts used in planning included fuel price forecasts from IHS Markit, 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.

## 2. ENCOMPASS RESULTS

The modeled costs associated with CCR, ELG, and 316(b) were incorporated into the EnCompass model. The costs associated with operations utilizing these emissions controls were reflected in unit operating costs and considered in the integration step of this IRP in conjunction with energy efficiency and various supply-side alternatives.

# E. EMISSION ALLOWANCE MANAGEMENT

The state of Indiana has an approved State Implementation Plan (SIP) to administer the CSAPR annual $SO_2$ and $NO_x$ programs. Tables F-1 and F-2 show the base number of Annual $SO_2$ and $NO_x$ allowances, respectively, allotted by the state of Indiana for affected units on the Duke Energy Indiana system for the CSAPR 2022 through 2025 control periods. With the issuance of the 2021 Revised CSAPR Update ozone season rule, the state of Indiana no longer has the authority to administer the ozone season program. Table F-3 shows the base number of seasonal $NO_x$ allowances allotted by the US EPA for affected units on the Duke Energy Indiana system for the CSAPR 2022 through 2025 control periods.

The emission allowance markets can impact compliance strategies. The projected allowance market price is a basis against which the costs of compliance options are compared to determine whether the options are economic (*i.e.*, a "market-based" compliance planning process). The market pricing for annual $SO_2$ and NOx allowances has seen a significant drop since 2015 (when the CSAPR program went into effect) due to substantial decreases in regional annual $SO_2$ and NOx emissions, resulting in low demand for allowances. Those emissions decreases have been driven largely by retirement of many older, uncontrolled coal-fired units and enhanced operation of controls on operating coal-fired units in response to the MATS rule. This causes low projected emission allowance prices for annual $SO_2$ and $NO_x$, typically below the variable cost of control. Therefore, the annual markets are not playing a significant role in the environmental compliance strategy at this time. Conversely, the ozone season NOx allowance market is currently a significant driver in compliance planning due to the additional limitations on NOx budgets resulting from the 2021 Revised CSAPR Update ozone season rule. The cost of NOx ozone season allowances is well above the variable cost of control and is an important factor on short-term planning impacting decisions relative to dispatch and operations and maintenance costs as well as on longer term strategies to maintain environmental compliance

Duke Energy Indiana maintains an interdepartmental group to perform $SO_2$ and $NO_x$ emission allowance management. Duke Energy Indiana manages emissions risk by utilizing a mixture of purchasing or 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 will be reviewed as the markets change and the most economic emission compliance strategy will be employed.

| **Table F-1** | | | | | | |
|---|---|---|---|---|---|---|
| SO2 Allowances (tons) Allocated to Duke Energy Indiana Units | | | | | | |
| **Station** | **Unit** | **Percent Ownership** | **2022** | **2023** | **2024** | **2025** |
| Cayuga | 1 | 100 | 5273 | 5273 | 2355 | 2355 |
| Cayuga | 2 | 100 | 5152 | 5152 | 2272 | 2272 |
| Edwardsport | CTG1 | 100 | 31 | 31 | 90 | 90 |
| Edwardsport | CTG2 | 100 | 75 | 75 | 94 | 94 |
| R Gallagher | 2 | 100 | 1126 | 1126 | 864 | 864 |
| R Gallagher | 4 | 100 | 920 | 920 | 748 | 748 |
| Gibson | 1 | 100 | 2782 | 2782 | 2782 | 2782 |
| Gibson | 2 | 100 | 2522 | 2522 | 2340 | 2340 |
| Gibson | 3 | 100 | 3173 | 3173 | 2608 | 2608 |
| Gibson | 4 | 100 | 3901 | 3901 | 3647 | 3647 |
| Gibson | 5 | 50.05 | 5570 | 5570 | 7574 | 7574 |
| Wabash River Gen Station | 6 | 100 | 3745 | 3745 | 0 | 0 |

## Table F-2

NOx Annual Allowances (tons) Allocated to Duke Energy Indiana Units

| Station | Unit | Percent Ownership | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Cayuga | 1 | 100 | 3344 | 3344 | 4057 | 4057 |
| Cayuga | 2 | 100 | 3267 | 3267 | 4273 | 4273 |
| Edwardsport | CTG1 | 100 | 46 | 46 | 451 | 451 |
| Edwardsport | CTG2 | 100 | 44 | 44 | 451 | 451 |
| R Gallagher | 2 | 100 | 714 | 714 | 483 | 483 |
| R Gallagher | 4 | 100 | 583 | 583 | 416 | 416 |
| Gibson | 1 | 100 | 4306 | 4306 | 2609 | 2609 |
| Gibson | 2 | 100 | 4540 | 4540 | 4698 | 4698 |
| Gibson | 3 | 100 | 4749 | 4749 | 3096 | 3096 |
| Gibson | 4 | 100 | 3966 | 3966 | 2537 | 2537 |
| Gibson | 5 | 50.05 | 3532 | 3532 | 4233 | 4233 |
| Henry County Gen Station | 1 | 100 | 24 | 24 | 44 | 44 |
| Henry County Gen Station | 2 | 100 | 26 | 26 | 45 | 45 |
| Henry County Gen Station | 3 | 100 | 19 | 19 | 45 | 45 |
| Noblesville Repowering | 1-3 | 100 | 60 | 60 | 69 | 69 |
| Duke Energy Vermillion, II LLC | 1 | 62.5 | 2 | 2 | 8 | 8 |
| Duke Energy Vermillion, II LLC | 2 | 62.5 | 3 | 3 | 7 | 7 |
| Duke Energy Vermillion, II LLC | 3 | 62.5 | 3 | 3 | 7 | 7 |
| Duke Energy Vermillion, II LLC | 4 | 62.5 | 3 | 3 | 6 | 6 |
| Duke Energy Vermillion, II LLC | 5 | 62.5 | 2 | 2 | 7 | 7 |
| Duke Energy Vermillion, II LLC | 6 | 62.5 | 2 | 2 | 9 | 9 |
| Duke Energy Vermillion, II LLC | 7 | 62.5 | 2 | 2 | 7 | 7 |
| Duke Energy Vermillion, II LLC | 8 | 62.5 | 3 | 3 | 5 | 5 |
| Wabash River Gen Station | 6 | 100 | 2375 | 2375 | 0 | 0 |
| Wheatland Gen Facility LLC | 1 | 100 | 27 | 27 | 65 | 65 |
| Wheatland Gen Facility LLC | 2 | 100 | 27 | 27 | 44 | 44 |
| Wheatland Gen Facility LLC | 3 | 100 | 20 | 20 | 55 | 55 |
| Wheatland Gen Facility LLC | 4 | 100 | 32 | 32 | 27 | 27 |

## Table F-3

NOx Sesaonal Allowances (tons) Allocated to Duke Energy Indiana Units

| Station | Unit | Percent Ownership | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|
| Cayuga | 1 | 100 | 541 | 394 | 396 | 374 |
| Cayuga | 2 | 100 | 558 | 407 | 408 | 386 |
| Edwardsport | CTG1 | 100 | 171 | 171 | 171 | 164 |
| Edwardsport | CTG2 | 100 | 184 | 173 | 174 | 165 |
| R Gallagher | 2 | 100 | 56 | 41 | 0 | 0 |
| R Gallagher | 4 | 100 | 53 | 38 | 0 | 0 |
| Gibson | 1 | 100 | 635 | 463 | 465 | 439 |
| Gibson | 2 | 100 | 596 | 434 | 436 | 412 |
| Gibson | 3 | 100 | 666 | 484 | 487 | 460 |
| Gibson | 4 | 100 | 588 | 428 | 430 | 407 |
| Gibson | 5 | 50.05 | 558 | 407 | 409 | 386 |
| Henry County Gen Station | 1 | 100 | 19 | 14 | 14 | 13 |
| Henry County Gen Station | 2 | 100 | 20 | 15 | 15 | 14 |
| Henry County Gen Station | 3 | 100 | 20 | 15 | 15 | 14 |
| Noblesville Repowering | 1-3 | 100 | 33 | 33 | 33 | 33 |
| Duke Energy Vermillion, II LLC | 1 | 62.5 | 5 | 5 | 5 | 5 |
| Duke Energy Vermillion, II LLC | 2 | 62.5 | 4 | 4 | 4 | 4 |
| Duke Energy Vermillion, II LLC | 3 | 62.5 | 4 | 4 | 4 | 4 |
| Duke Energy Vermillion, II LLC | 4 | 62.5 | 4 | 4 | 4 | 4 |
| Duke Energy Vermillion, II LLC | 5 | 62.5 | 4 | 4 | 4 | 4 |
| Duke Energy Vermillion, II LLC | 6 | 62.5 | 5 | 5 | 5 | 5 |
| Duke Energy Vermillion, II LLC | 7 | 62.5 | 4 | 4 | 4 | 4 |
| Duke Energy Vermillion, II LLC | 8 | 62.5 | 3 | 3 | 3 | 3 |
| Wheatland Gen Facility LLC | 1 | 100 | 18 | 13 | 13 | 13 |
| Wheatland Gen Facility LLC | 2 | 100 | 17 | 12 | 12 | 12 |
| Wheatland Gen Facility LLC | 3 | 100 | 13 | 10 | 10 | 9 |
| Wheatland Gen Facility LLC | 4 | 100 | 13 | 9 | 9 | 9 |

# APPENDIX G

DUKE ENERGY INDIANA

## CROSS-REFERENCE TO PROPOSED RULE

| IRP Section and Rule | Location in Duke Energy IRP Document |
|---|---|
| 170 IAC 4-7-4<br>Section 4 - Integrated Resource Plan Contents | |
| (1) Twenty-year forecast | Section IV |
| (2) Analysis of historical and forecasted peak demand and energy usage | Section III.A |
| (3) Alternative forecasts of peak demand and energy usage | Section IV |
| (4) Description existing resources | Section III.B |
| (5) Description of the utility's process for selecting possible future resources | Section II |
| (6) Description of possible future resources | Section V.B |
| (7) Screening analysis and summary table | Appendix C |
| (8) Candidate resource portfolios | Section V |
| (9) Preferred resource portfolio | Section I; Section VI |
| (10) Short term action plan | Section I; Section VI.B |
| (11) Inputs methods definitions for load forecasts | Section II |
| (12) Data sets and sources for load forecasts | Appendix B |
| (13) Effort to develop a database of electricity consumption patterns | Appendix B; Appendix D |
| (14) Suggested methods for developing database in (13) | No Response Required |
| (15) Schedule for customer surveys | Section II. A |
| (16) Usage of AMI data | Section III.C |
| (17) Contemporary issues designated | No Response Required |
| (18) Distributed generation | Section II; Appendix B |

| IRP Section and Rule | Location in Duke Energy IRP Document |
|---|---|
| (19) Model structure and applicability | Section II.B |
| (20) Fuel inventory and procurement planning | Section II.A |
| (21) Emission allowance inventory and procurement planning | Appendix F.B |
| (22) Generation expansion planning criteria | Section II.A and D; Section V |
| (23) Consideration of compliance costs | Section IV; Appendix F |
| (24) Resource planning objectives | Section II.D; Section V.A |
| (25) Base case scenario | Section IV |
| (26) Alternative scenarios | Section IV |
| (27) Description of power flow models and transmission planning criteria | Appendix E |
| (28) List and description of methods | Section II |
| (29) Avoided cost calculation | Appendix D |
| (30) Summary of public advisory process | Volume 2 |
| (31) Assessment of resources considered | Section II; Section V; Appendix C; Appendix D |
| **170 IAC 4-7-5 Section 5 - Energy and Demand Forecast** | |
| (a)(1) Historical load shapes | Section III.A; Appendix B |
| (a)(2) Disaggregation of data | Section III.A; Appendix B |
| (a)(3) Actual and weather-normalized levels | Section III.A; Appendix B |
| (a)(4) Methods to weather-normalize | Appendix B |
| (a)(5) 20-year energy and demand forecasts | Section IV, Appendix B |

| IRP Section and Rule | Location in Duke Energy IRP Document |
|---|---|
| (a)(6) 10-year historical analysis | Section III.A; Appendix B |
| (a)(7) Impact of historical DSM programs on load forecast | Appendix B |
| (a)(8) Justification for forecast methodology | Appendix B |
| (a)(9) Potential improvements for forecasting | Appendix B |
| (a)(10) Data sources for historical analysis | Appendix B |
| (b)(1) Alternative forecasts - high | Section IV; Appendix B |
| (b)(2) Alternative forecasts - low | Section IV; Appendix B |
| (b)(3) Alternative forecasts - most probable | Section IV; Appendix B |
| (c) Suggested inputs for most probable forecast | No Response Required |
| **170 IAC 4-7-6<br>Section 6 - Description of Available Resources** | |
| (a)(1) Net and gross dependable generating capacity | Section VI.A |
| (a)(2) Expected changes to existing capacity | Section VI.A |
| (a)(3) Fuel price forecasts by existing generating unit | Appendix A |
| (a)(4) Environmental effects at existing fossil generating units | Appendix A, Appendix F |
| (a)(5) Analysis of existing transmission system | Appendix E |
| (a)(6) Discussion of demand-side resources | Appendix B |
| (b)(1) Rate design as a resource | The company's EE & DR programs can be viewed as resources that have rate design elements to them. |
| (b)(2)(A) Description of potential DSM resources | Appendix D |
| (b)(2)(B) Methods by which DSM resource characteristics are determined | Appendix D |
| (b)(2)(C) Customer class affected by potential DSM resources | Appendix D |

| IRP Section and Rule | Location in Duke Energy IRP Document |
|---|---|
| (b)(2)(D) Annual and lifetime energy and savings for potential DSM resources | Appendix D |
| (b)(2)(E) Impact of potential DSM on load, capacity, and T&D requirements | Section V; Appendix D |
| (b)(2)(F) Ability of all ratepayers to participate in DSM | Appendix D |
| (b)(3)(A) Description of supply-side resources considered | Section V.B; Appendix C |
| (b)(3)(B) Description of efforts to coordinate planning with other utilities | At the time the company gets underway with a larger new resource addition, it will inquire about potential opportunities to coordinate with other utilities. This also takes place in transmission planning. |
| (b)(3)(C) Environmental effects of supply-side resources considered | Section V.B; Appendix F |
| (b)(4)(A) Transmission resources considered | Appendix E |
| (b)(4)(D) For transmission resources, timing, types, and alternatives considered | Appendix E |
| (b)(4)(E) Cost of expected transmission projects | Appendix E |
| (b)(4)(F) Value of transmission upgrades | Appendix E |
| (b)(4)(G) How IRP affects RTO planning and RTO planning affects IRP | Section II.D |
| **170 IAC 4-7-7<br>Section 7 - Selection of Resources (Screening Analysis)** | Section II.C; Appendix C |
| **170 IAC 4-7-8<br>Section 8 - Resource Portfolios** | |
| (a) Process for selecting candidate portfolios | Section II.E; Section II.F |
| (b) Candidate portfolio performance across scenarios | Section V.F |
| (c)(1) Preferred resource portfolio | Section I; Section VI |

| IRP Section and Rule | Location in Duke Energy IRP Document |
|---|---|
| (c)(2) Standards of reliability | Section II.D |
| (c)(3) Assumptions having greatest effect on preferred resources portfolio | Section V |
| (c)(4) Analysis showing that supply-side and DSM have been considered on a consistent basis | Section II; Section V; Appendix D |
| (c)(5) Analysis showing that portfolio meets demand | Section V; Section VI.A; Appendix A |
| (c)(6) Analysis of DSM deferring T&D investment | Appendix E |
| (c)(7)(A) Operating and capital cost of preferred portfolio | Appendix A |
| (c)(7)(B) Avg. cost/kWh of future resources | Appendix A |
| (c)(7)(C) Avoided cost in each year for preferred portfolio | Section IV; Appendix D |
| (c)(7)(D) Ability to finance preferred portfolio | Section 1.B |
| (c)(8) How preferred portfolio balances cost, reliability, risk | Section V; Section VI.A |
| (c)(9) Discussion of potential improvements | Section VI.D |
| (c)(10) Strategy for adapting to change in assumptions | Section VI.C |
| 170 IAC 4-7-9<br>Section 9. Short-term action plan | Section I; Section VI.B |

# VOLUME III

## NON-TECHNICAL SUMMARY & STAKEHOLDER COMMUNICATIONS

*SEE SEPARATE ATTACHMENT*

BUILDING A **SMARTER** ENERGY FUTURE ®