



**Draft Director's Report
For Duke Energy Indiana (DEI) 2024 Integrated
Resource Plan**

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Draft Director's Report Applicable to Duke Energy Indiana's 2024 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Duke Energy Indiana's (DEI's) 2024 Integrated Resource Plan (IRP) was submitted on Nov. 1, 2024. By statute and rule, integrated resource planning requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The Director's report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of integrated resource planning, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting. By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

Duke Energy Indiana, like every Indiana utility and stakeholder, anticipates substantial changes in the state's resource mix due to several factors and, increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive long-term plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

II. INTRODUCTION AND BACKGROUND

From the Director's perspective, DEI, like most utilities across the United States, is addressing resource changes in an environment of extreme uncertainty regarding government policy, commodity prices, and technology. To better address these uncertainties, the 2024 IRP included several significant improvements compared to the 2021 IRP.

- Incorporation of Indiana's Five Pillars of energy policy.
- Enhanced evaluation of the resource adequacy of portfolios and stochastic analysis to measure the robustness of portfolios.
- A more rigorous approach to alternate load forecast sensitivities and additional detail on load forecasting methodology.
- Significant economic development activity, including additional high load sensitivities.

Consistent with the issues discussed above, the Director's report will focus on three broad areas: (1) load forecasting; (2) assessment of demand-side resources broadly defined to include energy efficiency, demand response resources, electric vehicles, and other distributed energy resources; and (3) portfolio development & scenario/risk analysis.

III. LOAD FORECASTING

DEI recognizes that 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 that load. The general load forecast framework includes: a national economic forecast; a service area economic forecast; an energy forecast prepared by estimating statistical models based on these economic conditions and market driven energy efficiency analysis; ex post modifications to account for the growth in electric vehicles (EVs), behind-the-meter solar, economic development, and wholesale contracts; and using the energy forecast to develop summer and winter peak demand forecasts.

The residential class sales forecast comprises of two projections: (1) the number of residential customers, which is driven by population, and (2) energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices, and appliance efficiencies. The residential usage per customer forecast was developed using a Statistically Adjusted End-Use (SAE) model. This model captures naturally occurring energy efficiency, electrification trends, and government mandates more explicitly than standard regression models, combining them with data on economic variables and weather to estimate how demand for energy might change over time as these factors change.

The commercial forecast projects aggregate energy demand also using an SAE model which models at the end-use level by building type to account for naturally occurring and government mandated energy efficiency changes and electrification trends and energy-price driven changes in electric fuel share of the commercial market.

According to DEI, total energy for the industrial class is forecasted by a standard econometric model. The econometric model has drivers such as total manufacturing output and the price of electricity. The U.S. Energy Information Administration (EIA) uses a process model for the industrial class which captures rapid consumption changes due to efficiency gains, electrification

fuel price changes, and co-generation process changes. The industrial forecast referred to the EIA industrial forecast for confirmation of the DEI forecast.

In addition, large customer loads are analyzed and added separately based on history and known future activity which are provided by large customer account and economic development managers.

The government class includes sales to facilities such as public schools, government buildings, and water pumping stations. The government monthly sales forecast is developed using a linear regression model and is most significantly driven by government employment and weather variables.

Street lighting is projected using a separate linear regression model that trends historical lighting usage and forecasts those sales into the future.

Wholesale hourly load and monthly sales are provided by the Wholesale Analytics group based on existing contracts with wholesale customers through 2030. For 2031 to 2044, the contract volumes for 2030 are assumed to continue through the forecast horizon.

Peak demands are projected using the SAE approach and reflect an adjustment for the mix of end uses at the time of peak. The peak forecast was developed using a monthly SAE model, like the sales SAE models, which includes monthly appliance saturations and efficiencies, interactions with weather, and the fraction of each appliance type that is in use at the time of monthly peak.

A. Economic Development and the Load Forecast

DEI also includes in the load forecast economic development projects likely to have a substantial impact on the load forecast. DEI's Economic Development and Large Account Management teams continually track and engage with potential economic development projects with many forwarded to the load forecasting team. The focus is on projects large in magnitude with sufficiently developed plans such that demand can be anticipated with a high degree of certainty. These projects are used to adjust the econometric industrial load forecast.

Combining the large load forecast with the results of the econometric model introduces a possibility of some double counting to the extent economic forces motivate the individual site adjustments. To mitigate double counting, DEI adjusts the forecasted economic development projects based on the insights and experience of the Economic Development and Large Account Management teams, resulting in a reduced amount of the full load expectation. In the 2024 base load forecast, this adjustment was a discount of approximately 40%.

The economic development forecast adjustment does not include supplier jobs or induced jobs created by the economic development projects.

B. Behind-the-Meter Solar Forecast

The behind-the-meter (BTM) solar forecast is a modifier to the load forecast, acting as a reduction to the load. The forecasts are developed for residential, commercial, and industrial customers at an hourly level. The BTM forecast uses regression modeling to estimate the relationship between installations and payback. Historical data is used to determine the relationship with the resulting regression equation and future payback projections used to estimate future adoptions. The number of adoptions is converted to capacity using historical size estimates. The capacity is then converted

into energy estimates by applying hourly production profiles. The hourly energy data is used to modify the load forecast.

The BTM solar adoption is expected to grow annually at a rate of around 10% over the next decade, reaching a total of 1.5% of customers in 2034. High and low BTM forecasts were created by adjusting the payback model variables of system costs and investment tax credits (ITCs).

C. Electric Vehicle Forecast

The EV load forecast is developed using the Guidehouse Vehicle Analytics and Simulation Tool (VAST). VAST develops the vehicle forecast using a total cost of ownership calculation based on multiple historical and forecasted parameters such as vehicle registrations, vehicle manufacturer's suggested retail price, battery efficiency characteristics, projections of fuel costs, future vehicle availability, and vehicle miles traveled.

The associated energy and load are forecasted once the vehicle adoption forecast is complete. Variables to determine energy, such as vehicle miles traveled and vehicle efficiency, are used to calculate charging energy requirements for the vehicles. Load charging profiles are based on public, private, and third-party analysis. These charging profiles are broken down into light, medium, and heavy duties.

Based on the adoption forecast, the projected amount of energy needed to charge the EVs, the hourly EV demand profiles, and the EV 8,760 hourly load forecast are developed. All three duties are calculated using a similar methodology and make up the EV load forecast that is added to the DEI load forecast.

High and low EV forecasts were developed to capture a broad range of EV adoption, which were used as key inputs to the alternate system load forecast scenarios. The high and low EV forecasts were created by adjusting the forecasted manufacturer's suggested retail price for EVs, the number of EV models available to purchase, and consumer preference towards EVs relative to traditional internal combustion engine vehicles.

D. Alternate Load Forecasts

The load forecast is sensitive to assumptions on economic growth, EV adoption, BTM adoption, and economic development, so alternative load forecasts were created to address these uncertainties. For the Base Load Forecast, the economic forecast is the 50/50 case from Moody's. The Base Load Forecast also includes the most likely case for adoption of EVs and the most likely case for adoption of BTM solar generation. For economic development, the Base Load Forecast assumes 60% of the announced economic development peak and energy additions occur.

The Low Load Forecast uses the 90/10 economic case from Moody's. The Low Load Forecast also includes the low case for EV adoption and the high case BTM solar generation. For economic development, the Low Load Forecast assumes 25% of the announced economic development peak and energy additions occur.

The High Load Forecast uses the 10/90 economic case from Moody's. The High Load Forecast also includes the high case for EV adoption and the low case for adoption of BTM solar generation. For economic development, the High Load Forecast assumes that 75% of the announced economic development peak and energy additions occur. Beyond the 75% of the announced economic development projects, an additional 500 MW of data center load was added over five years

(approximately 100 MW per year starting in 2027). Also, the economic development assumption is used to derive secondary employment created by the primary activity assumed in the economic development case, boosting commercial and industrial electric sales.

Director's Comments – Load Forecasting

DEI's 2018 and 2021 IRPs contained little information about the load forecast methodology. The 2024 IRP, in contrast, contains a lengthier and much more detailed write-up, which is a significant improvement.

- a. While many readers may be familiar with SAE models, the appendix should still include a detailed explanation of them.
- b. The industrial model is now a total sales econometric model with total manufacturing output and electricity price as drivers. The language on page 342 states "drivers such as" suggests the model may have more drivers. Does it? Figure D-5 on page 349 and the text on pages 350-351 help answer this question but this could be clarified at the time the model is first discussed.
- c. The industrial forecast section on page 342 refers to EIA's "process model" that the industrial model is compared to. It is not clear what this process model is or how it is used.
- d. Weather variables are discussed on page 343. What base temperature is used for degree-day calculations? Indianapolis weather station is being used, and while it is in the middle of the service territory, that territory extends far to the south and well into the northern part of the state. Would an average of multiple weather stations provide better results?
- e. Governmental sales are forecasted using a linear regression model on monthly sales as a function of government employment and weather. The language on page 343 states "most significantly driven" by the aforementioned variables. This suggests the model has other variables. What are they? Figure D-5 on page 349 only lists those two variables as well.
- f. What does "effective price" mean in the first paragraph on page 344?
- g. The footnote on page 345 states that EIA did not publish the Annual Energy Outlook (AEO) in 2023 as the reason for Itron using the 2022 AEO report. EIA did, in fact, publish the AEO in 2023, although not 2024. Is this a typo? If not, why was the AEO for 2022 used?
- h. Table D-2 on page 348 shows only cooling degree days as a weather driver for industrial sales. However, page 351 lists both heating and cooling degree days as drivers in the industrial model. Are heating degree days used in the industrial model?
- i. The information about models and their drivers seems to be spread out over several sections leaving the reader to go back and forth through the document to fully understand the load forecasting modeling approach. The information is mostly there, but the order in which it is presented could be improved.

IV. DEMAND-SIDE RESOURCES

A. Summary and Overview

As in the previous IRP, Duke continues to engage Resource Innovations (RI) to conduct the Market Potential Study (MPS) to evaluate multiple scenarios for potential future energy savings. RI explored technical, economic, and achievable market program potential for that study. The economic potential energy and capacity savings were determined using the utility cost test (UCT). For the achievable market potential, the estimates adjust the customer base to remove customers who opted out of energy efficiency (EE) and include estimated impacts from the Inflation Reduction Act (IRA) funding. For the analysis, RI assumed that Duke will continue to adaptively manage programs, following the EE/demand response (DR) program life cycle: market assessment, program design, implementation, evaluation, and adaptation. The results of the MPS also inform EE and DR resource cost and availability assumptions. Avoided costs used in the MPS were newly developed.

B. Energy Efficiency Resources

DEI is currently implementing its 2024-2026 EE portfolio, as approved by the Indiana Utility Regulatory Commission under Cause No. 45803. The EE forecasts used in this 2024 IRP are based on a combination of this approved portfolio along with future projections of energy savings potential provided in the MPS for periods beyond 2026. The EE programs included in the 2024-2026 portfolio are included in the 2024 IRP modeling in all cases. The EE MPS included multiple scenarios for projecting future energy savings potential impacts from EE and DR programs for a 25-year forecast period (2025-2049). The identified achievable potential programs in the MPS were designed under the UCT to pursue cost-effective EE savings.

For this IRP, DEI developed nine sub-portfolios or bundles of residential and non-residential EE programs as demand-side resource options for selection. These bundles are modeled similarly as supply-side resource options which are optimized in the IRP process and selected based on economics. The energy savings in the EE bundles were modeled based on the currently approved EE portfolio and two of the three 2024 MPS scenarios: the Base Scenario and the High Incentive Cost Scenario.

The three scenarios modeled in the MPS are:

1. *Base*: reflects current Duke Energy programs and program costs, incentive rates, and utility avoided cost benefits generated by the program; includes estimated impacts from the 2022 IRA.
2. *High Incentive*: doubles current incentive rates with a cap at 75% of the measure incremental cost; applies utility avoided cost benefits from the base scenario.
3. *High Avoided Costs*: increases utility avoided cost benefits by 50%, uses base scenario incentive rates.

The EE programs in the IRP are divided into five distinct time periods: 2024-2026, 2027-2029, 2030-2033, 2034-2041, and 2042-2049. To provide the model with granularity of options, bundles were only developed for the last four periods. For the first bundle (2024-2026), the IRP model was required to select the entire bundle that reflects the savings and costs associated with the currently approved demand side management (DSM) portfolio.

For all subsequent bundles (2027-2049), 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 Base Bundle or the High Incentive bundle. The high bundle includes greater savings than the base bundle but requires more incentives to achieve those savings. The base and high bundles are mutually exclusive, and the model may select only one of the two in each year they are available.

C. Demand Response Resources

Current Duke DR programs include Power Manager®, Power Manager® for Business, PowerShare® and Savings on Demand, and special contract customer DR. The 2024 IRP includes these existing DR programs and a new undesignated DR resource that serves as a representative proxy for future demand response initiatives.

DR programs' capacity is modeled as peaking resources and contributes to capacity reserve margins. According to Duke, DR capacity in this IRP is grossed up for reserve margin and transmission losses, and, unlike in the 2021 IRP, its contributions are forecasted (locked in) rather than evaluated as a selectable resource option in the capacity optimization model.

According to the IRP, Duke is closely monitoring the implementation of Federal Energy Regulatory Commission (FERC) Order 2222. The peak reductions identified in the 2024 IRP assumes no impact from this Order until 2030, and even then, DEI assumes a slow ramp.

D. Integrated Volt/Var Control

Duke is continuing the implementation of Integrated Volt/Var Control (IVVC) to better manage the application and operation of voltage regulators (Volt) and capacitors (VAR) on the distribution network. Duke primarily operates IVVC in the form of Conservation Voltage Reduction (supports continuous voltage reduction and energy conservation). In 2023, Duke received approval from Midcontinent Independent System Operator (MISO) to register IVVC as a Load Modifying Resource (LMR). The program's deployment began in 2019 under DEI's Transmission, Distribution, and Storage System Improvement Charge (TDSIC) 1.0 and is ongoing under TDSIC 2.0.

The program is expected to reduce demand on the distribution system by approximately 0.69% in 2024, with a forecasted reduction of about 0.8% in 2029 and beyond. The supply and demand impacts of the IVVC program are included in the IRP capacity expansion and production costing modeling.

E. Rate Design

Duke is also pursuing customer programs to facilitate EV adoption (Make-Ready Credit program), provide more direct access to renewable energy sources, and manage customer demand through time-of-use (TOU) rates for residential and commercial and industrial (C&I) customers. The existing Low Load Factor Secondary Service rate is being closed to new participants and replaced with an improved design. The impacts of these programs are not directly included in the 2024 IRP analytics, but the impacts will be seen in future IRPs.

Director's Comments – Demand-Side Resources

The inclusion in Appendix H of the MPS prepared by RI is helpful but is no substitute for a discussion in the body of the IRP document of how the MPS results were used to model the effects of EE and DR in the IRP capacity optimization model. The following questions highlight the degree to which basic information was not provided.

- a. In the section “Appendix H” of the IRP document, Duke mentions that “the Company assumes a slow ramp” in peak reduction capabilities after 2030 due to the FERC 2222 rule. Also, it says that “The 2024 IRP currently includes... an adder for forecasted impacts of FERC 2222”. However, there are no specifics regarding the size of this adder and/or the criteria to determine that adder.
- b. What assumptions were behind developing the EE bundles for the current IRP using only the base and high incentive scenarios from the MPS? Why was the high avoided cost case not considered? Furthermore, there is limited information on the specifics of the methodology used to design and choose the final 10 EE bundles that were incorporated as inputs in the IRP’s model.
- c. According to the 2024 IRP document, “Contributions from DR are forecasted rather than model-selectable.” Why was DR modeled differently in this IRP than in the 2021 IRP, where the DR programs were modeled as selectable bundles? Also, it is unclear what assumptions were used to model DR resources in the current IRP.

V. PORTFOLIO DEVELOPMENT & SCENARIO/RISK ANALYSIS

A. Models

For this IRP, DEI used the EnCompass planning model. EnCompass’ economic optimization model was used to develop portfolios while satisfying reliability criteria. The model assesses the economics of various resource investments including conventional generating units such as combustion turbines, combined cycles, 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. Ten sub-portfolios of EE programs (also referred to as “bundles”) were developed and were treated similarly to supply-side resource options for selection by the IRP models.

EnCompass was also used as a detailed production-cost model for simulation of the optimal operation of an electric utility’s generation facilities. EnCompass uses 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 portfolio. Key EnCompass inputs include generating unit data, fuel data, load data, transaction data, DSM data, emission and allowance cost data, and utility-specific system operating data.

In the IRP, DEI used 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 Eastern Interconnect resource mix. DEI used Horizon Energy’s database within EnCompass to develop scenario specific expansion plans for all of the Eastern Interconnect. The expansion plans were then run on an hourly basis to estimate the 20-year hourly power price for

DEI. This method ensured consistency between the power price forecasts and the DEI EnCompass runs with regards to fuel and load assumptions.

Both the capacity expansion model and the production cost model in the Encompass software package are deterministic models, meaning each model relies on fixed forecasts for load, fuel prices, and other inputs allowing the models to solve more quickly. The deterministic approach, for example, is necessary for the production cost model to be able to evaluate every hour of the 20-year planning horizon in a reasonable amount of time.

DEI also used two additional models, Strategic Energy Risk Valuation Model (SERVM) and PowerSIMM to further evaluate the operational characteristics of the resource portfolios produced in the EnCompass model. Both production cost-type models are considered “stochastic” due to their ability to simulate multiple, path-dependent scenarios of system dispatch. Stochastic modeling can reveal uncertainties and risks that single scenario, deterministic models may not show. These stochastic models were used to simulate hundreds to thousands of years of hourly dispatch to quantify operational, economic, and reliability uncertainties.

B. Method

The analytical framework used by DEI was designed to evaluate the risks, uncertainties, and potential trade-offs relative to specified planning objectives when comparing diverse resource portfolios. The framework includes generation strategies, planning scenarios, and sensitivity analyses.

The generation strategies were designed around the compliance pathways mandated by the U.S. Environmental Protection Agency (EPA) Clean Air Act (CAA) Section 111 Rule, which directly limits the flexibility to optimize resource modeling for existing coal units. DEI created two “bookend” generation strategies: one where all coal units are converted to natural gas or natural gas and coal co-firing by 2030, and the other where all coal units are retired by 2032. DEI then considered different combinations of compliance options for each coal unit and the insights from the two “bookend” strategies to develop additional generation strategies, referred to as blends. In this process, DEI created six distinct generation strategies. Each generation strategy is based on specific compliance options for existing coal units, and the model optimizes selection of new resource additions.

The second step was the development of alternative scenarios or worldviews. Scenarios are designed to test a portfolio’s performance across a diverse range of future worlds. The scenarios are not predictions of what the future will be, but what the future could plausibly be. The idea is to evaluate the robustness and flexibility of resource plans in the face of uncertainty.

For scenario development, load, fuel prices, resource options, and laws and policies were selected as the foundational key variables, with policy and innovation being identified as pivotal drivers potentially leading to dramatically different future outcomes. The scenarios for the future consisted of (1) the Reference Scenario, which included existing regulations and DEI’s base forecasts and expectations for the most likely future, (2) Aggressive Policy & Rapid Innovation, which assumed regulatory and technological factors incentivize and enable a more rapid energy transition, and (3) Minimum Policy & Lagging Innovation, which assumed a more lenient regulatory environment, including reversal of the EPA CAA Section 111 Rule, and a slower pace of energy transition. The distinct assumptions in each scenario significantly impact the resource optimization outcomes, as the different assumptions dictate the pace of energy transition, the feasibility of technology adoption, and the economic viability of resources.

DEI also evaluated multiple generation strategy variations regarding EPA CAA Section 111 and alternative combinations of resource options at various time points. For sensitivity analysis, key externally driven uncertainties on portfolio resource choices and performance were evaluated, including resource technology capital costs, load, and fuel prices.

There are 18 scenario portfolios developed from the six generation strategies modeled under three scenarios. Six portfolios were also developed under various generation strategy variations optimized to the Reference Scenario. Sensitivity analysis added another 20 portfolios. With one more stakeholder supplemental portfolio, the Deep Decarbonization and Rapid Electrification portfolio, there are 45 candidate portfolios in total.

Finally, all resource portfolios were evaluated and compared using a scorecard that considered reliability, affordability, resiliency, stability, environmental sustainability, and risk and uncertainty.

C. Stochastic Simulations

DEI performed a new modeling step to compare and assess the portfolios on their contributions to future reliability. This evaluation created thousands of simulations as part of a probabilistic reliability analysis using SERVM. Key features of SERVM include weather uncertainty simulation, unit availability uncertainty simulation, economic load forecast error, and 8,760 hour production cost simulation.

DEI used SERVM to evaluate islanded portfolio dispatch to identify future periods of heightened operational risk from uncertainties in load and generator performance. DEI used SERVM to simulate generation dispatch of the generation strategies in the Reference Scenario through 11,000 simulations for the years 2028 and 2035. Based on the hourly system dispatch simulation, the SERVM model shows when DEI resources are not sufficient in a given hour – the amount of load potentially unserved if DEI did not have access to the broader MISO market to maintain reliability.

Another new stochastic economic analysis was performed using PowerSIMM to assess the impact of uncertainty around future market conditions. The PowerSIMM production cost model uses a specified set of resources developed using the capacity expansion model to perform detailed hourly forecast of generation. PowerSIMM performs hundreds of iterations based on weather, load, solar, wind, forced outages, fuel, and power prices simulated by iteration.

DEI used PowerSIMM to provide a more granular look at market exposure for the various portfolios developed using EnCompass. For example, market exposure to power prices risks upside shock to the consumer, while market exposure to fuel prices risks generating asset underperformance in years with low market power pricing relative to the assumed baseline.

Using PowerSIMM, DEI analyzed the six generation strategies in the Reference Scenario for the years 2028, 2035, 2040, and 2044. The stochastic analysis created a range of outcomes for each generation strategy for key output variables such as net market purchases, CO2 emissions, and operating costs.

D. Scorecard Metrics

Capacity expansion model optimization for a specific scenario may develop a resource portfolio that performs poorly under alternative futures. The model minimizes future costs for a scenario, but the model does not make judgments about other factors (e.g., fuel diversity, environmental impacts, etc.) that may affect the desirability of a resource portfolio.

DEI prepared a scorecard to help evaluate the various portfolios and their relative performance across metrics beyond cost minimization. The scorecard metrics are categorized by planning objectives built on the Five Pillars (reliability, affordability, resiliency, stability, and environmental sustainability) and risk and uncertainty. The scorecard included the following metrics:

Reliability

- *Fast Start Capability*: Fast-start capable resource capacity MW as a percent of peak load in 2025. Resources included are combustion turbines and batteries.
- *Spinning Reserve Capability*: Spinning reserve capable resource capacity MW as a percent of peak load in 2025. Spinning reserve capable resources include steam, combined cycle, combustion turbine (CT), combined heat and power, and hydro.

Affordability

- *Present Value Revenue Requirement*: Total forecasted revenue requirement associated with resource plan investments over the planning period, discounted to present.
- *Customer Bill Impact*: Average annual rate impact to customers over 5-year and 10-year time periods expressed as projected compound annual growth rate in customer bill of a typical residential household using 1,000 kWh/month associated with resource plan investments, inclusive of existing unit ongoing costs.

Resiliency

- *Resource Diversity*: System diversity by technology type as measured by the Herfindahl-Hirschman Index (the sum of the squares of technology share in the portfolio on a firm capacity basis in 2035).
- *Simulated EUE in 95th Percentile Cold Weather as an Islanded System*: Stochastically simulated expected unserved energy (EUE) as a percent of load during coldest weather (95th percentile or colder) observed in Indiana over the past 44 years with market purchases turned off.

Environmental Sustainability

- *CO₂ Emissions Reduction*: Percent CO₂ emissions reduction at specified years (2035 and 2044) relative to 2025, including CO₂ emissions associated with market purchases.
- *Cumulative CO₂ Reduction*: Cumulative volume of CO₂ reduction over the planning period, reflected as millions of tons reduced through 2044 relative to 2025 including estimated CO₂ emission associated with market purchases.
- *CO₂ Intensity of DEI Portfolio*: CO₂ emissions from DEI resources per MWh of energy generated by those resources.

Cost Risk

- *Cost Variability Across Scenarios*: The minimum and maximum PVRRs of the portfolio across the scenarios evaluated.
- *IRA Exposure*: Portion of cumulative MW additions assumed to receive IRA credits relative to total resource additions through 2030 and 2035.

Market Exposure

- *Fuel Market Exposure*: Energy generated by resources with exposure to coal and gas market prices as a percent of total fleet generation, averaged annually over the planning period.
- *Maximum Energy Market Exposure*: Absolute value of maximum single year annual energy purchase net of sales as percent of load.

Execution Risk

- *Cumulative Resource Additions in MW*: Cumulative MW additions of all capacity resource technology types, including DSM, through 2030 and 2035, expressed in MW.
- *Cumulative Resource Additions as a percent of Current System*: Cumulative MW additions of all capacity resource technology types, including DSM, through 2030 and 2035, expressed as a percent of total MW capacity serving customers today.

DEI did not include in the scorecard metrics for stability. DEI initially considered measuring the rate of change of inertial megawatts as an indication of risk to stability from operational complexities as the fleet is transitioned to increasing penetration of renewable resources. DEI also considered measuring the penetration of inverter-based resources (IBRs) in a future resource portfolio as a means of indicating risk to stability and potential voltage support issues that could arise with a high penetration of IBRs.

Stakeholders recommended instead a narrative approach to this planning objective. DEI decided not to use quantitative metrics for stability and opted to describe potential issues and future challenges that may arise while dispatchable resources are retired and intermittent generation becomes a larger share of generation in the DEI portfolio and the broader MISO region.

Table 4-2 (page 130) of the DEI IRP Report summarized the scorecard results across the six generation strategies in the Reference Case scenario.

Director's Comments – Portfolio Development & Scenario/Risk Analysis

The IRP planning exercise is increasingly complex. The evaluation of different resource portfolios necessary involves a balancing of numerous risks and uncertainties inherent in an unknowable future. Judgment is unavoidable and needs to be directly addressed and emphasized throughout the IRP planning process. The Director thinks DEI did this well.

DEI does a good job of incorporating and documenting their use of the Five Pillars in the IRP. The three metrics added to address risk and uncertainty are helpful by drawing attention to this aspect of planning. However, the issue of risk and uncertainty is a key consideration in the design and structure of the IRP analysis and can be seen in all components of the IRP. DEI's discussion of the risk and uncertainty is not limited to that contained in the scorecard metrics. Use of scorecard metrics relies on what can be quantified when there is so much more that needs to be accounted for in other ways.

As discussed above, DEI described two quantitative metrics it considered to assess portfolio performance on the stability pillar. DEI also explained why it decided not to use quantitative measures of stability and instead relied on a narrative discussion of the factors affecting stability. DEI presented this as an either/or decision when it would have been reasonable to do both.

The affordability pillar is the most debated by stakeholders. DEI evaluated affordability using two very different metrics.

1. *Present value of revenue requirements*: Includes all annual costs for operating the system along with the economic carrying charge for all new resources. Annual values are discounted back to the beginning of 2025 using DEI's weighted average cost of capital (WACC).
2. *Compound Annual Growth Rate (CAGR)* uses a depreciating rate base methodology instead of the economic carrying charge used in the EnCompass capacity expansion model. The bill impact calculation includes revenue requirements for each portfolio utilizing capital, operations and maintenance (O&M), and IRA benefits for each plan. Bill impacts consist of the development of return and depreciation of each type of asset through the study period. The bill impacts use DEI-specific WACC, 2024 rate case cost of service, and the 2024 rate case residential bill as the basis of the calculation. The revenue requirements are adjusted to reflect only the retail impacts. All bill impacts are calculated as incremental changes from 2025.

It is important to understand what the PVRR and bill impact analyses include and exclude in their respective calculations. As noted by DEI, the PVRR calculation does not account for costs not related to resource planning, and it excludes unavoidable costs and costs that are assumed to be constant across all resource portfolios. According to DEI, the bill impact calculation similarly excludes costs not germane to resource planning, costs that are unavoidable, and certain costs that are the same across resource portfolios. In contrast to the PVRR calculation, capital costs for new resources are included using a depreciating rate base methodology rather than being levelized over the life of the asset. Also, the bill impact analysis does not include the depreciation of existing assets, schedules for which are determined in rate cases and are not necessarily directly linked to actual retirement dates for physical assets. DEI notes that the bill impacts are useful for resource portfolio comparison only and cannot be used to estimate actual customer bills at any point in the future.

The Director sees affordability as especially complicated in today's utility planning environment. Within this environment, it is important to keep some basic principles in mind.

- a. Evaluation of affordability requires judgment because it is contingent on maintaining desirable performance across other characteristics of utility customer service both qualitative and quantitative in nature.
- b. Determination of affordability requires a comparison of different resource portfolios (or choices) over a 20-year planning period accounting for a range of alternative potential futures.
- c. The traditional primary methodology is to use present value revenue requirement to evaluate choices on a comparable basis.
- d. Calculating the net present value revenue requirements (NPVRR) for different portfolios allows a comparison of the overall incremental cost of each portfolio for all customers over the planning period. The process involves identifying known incremental costs of various portfolios over a planning period and determining the incremental revenue

requirement effect of these costs in each year of the planning period, then discounting to account for the time value of money.

- e. Affordability in resource planning is measured relative to the performance of other portfolios accounting for the other pillars and the risks and uncertainties of an unknowable future.

The focus of NPVRR is appropriately on those costs that can be avoided or incurred depending on the resource choices made. Attention is not paid to those costs that cannot be avoided or undone regardless of the possible resource choices going forward. The assumption is that these costs must be recovered regardless of the resource choices going forward. These unavoidable costs will be accounted for in customer rates, but their recovery does not depend on resource choices going forward and, therefore, should have limited impact on future decisions.

The Director thinks it is particularly helpful when the annual revenue requirement used to calculate the NPVRR for each resource portfolio is presented in both nominal and real dollars.

The above discussion does not mean that current uncertainty associated with large load additions and rapid load growth might not necessitate modifications to the NPVRR metric. Comparing resource portfolios with very different load forecasts and aggregate resource additions is problematic.

A helpful addition by DEI was to include the evaluation of average annual rate impact to customers over 5-year and 10-year time periods expressed as projected compound annual growth rate in the bill of a typical residential household customer using 1,000 kWh/month associated with resource plan investments, inclusive of existing unit ongoing costs. This metric does not provide information on the overall cost effectiveness of different resource choices over a long planning period while accounting for the risks and uncertainties of an unknowable future, but the metric does help identify possible near-term rate impacts. The Director thinks this information is a complement to both the traditional NPVRR and the presentation of the annual revenue requirement for each resource portfolio in both nominal and real dollars. The key consideration is to have information on both the long-term cost effectiveness of different resource portfolios while also having a better understanding of potential near-term impacts of different choices.

Considering regional resource changes in utility IRP planning processes is an important step as the appropriate utility resource portfolio probably differs as the regional portfolio changes. In other words, the resource choices of Indiana utilities should impact the choices of utilities throughout the MISO region and vice versa. This is an interactive process that is difficult to capture in the models. The Director thinks more needs to be done to account for these broader regional conditions, but it is not obvious how this can best be done. The fact that utility IRPs are updated on a regular schedule helps to lessen slightly the importance of this limitation.

DEI recognizes that its resource portfolio operates in a broader regional portfolio that is undergoing significant changes. The issue is how best to account for this regional change in DEI's IRP development process. In this context, DEI implemented two new stochastic tools to evaluate the performance of diverse resource portfolios: one used SERVIM to assess portfolios on their contributions to future reliability by evaluating islanded portfolio dispatch to identify future periods of heightened operational risk from uncertainties in load and generator performance, and the second used PowerSIMM to assess the impact of uncertainty around future market

conditions. The idea was to better understand the risk of different levels of market exposure associated with different resource portfolios.

The Director believes these are helpful additions to the long-term resource planning process. Understanding how a resource portfolio might perform if DEI is in an islanded condition is insightful even if the assumption of islanded operation is extreme. To better understand the extent of potential economic risks associated with varying levels of market exposure is a nice complement. One stochastic process helps to better think about the reliability implications of resource choices while the other stochastic process helps to draw attention to potential market exposure.

VI. STAKEHOLDER COMMENTS

The following comments are intended to be a representative sampling of the public input into DEI's 2024 Integrated Resource Plan. There were similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Advanced Energy United (AEU)

AEU highlights concern with Duke's IRP in four key areas, discussed further below.

Cost Assumptions for Electricity Generation and Storage Technologies

AEU suggests that DEI overestimated the overnight capital cost (OCC) for solar, wind and storage by several hundred dollars per kilowatt compared to thermal resources. Specifically, the commenter applies the OCC values from the EIA's Assumptions for the Annual Energy Outlook 2023: Electricity Market Module, adjusting from 2022 dollars to 2024 dollars using the U.S. Bureau of Labor Statistics Consumer Price Index Inflation Calculator.

VPP Opportunities

AEU notes that while DEI recognizes the value of DR as a demand-side resource, it underappreciates the potential of virtual power plants (VPPs) in Indiana. AEU points to several successful VPP programs in other jurisdictions and recommends that DEI implement similar programs to leverage existing distributed energy resources (DERs) and enhance grid value.

Valuing BTM DERs

AEU points out that only 0.47% of DEI's customers utilize BTM solar, equating to 87 MW of generation. AEU suggests that incentivizing BTM solar could be a cost-effective way to meet growing demand. AEU recommends that the Director encourage DEI to model and determine what level of utility-provided financial incentive (\$/kW installed) would achieve a desired megawatt volume of BTM distributed generation and then evaluate whether the total program is cost-effective.

Coordinated Utility Planning

AEU recognizes that the shift towards electric appliances necessitates greater coordination between electric and gas industries in planning. AEU is concerned, for example, with heat pump sales, which have exceeded natural gas furnace sales for three consecutive years and may not be adequately considered in DEI's load forecast. AEU recommends that DEI coordinate with gas utilities in its service area to better understand gas usage trends that could affect electricity consumption.

Response of DEI

1. *Coordinated Utility Planning*: Specifically addressing electrification trends, DEI pointed to pages 347 to 352 of the IRP, where key load forecast drivers, such as appliance efficiencies and saturation, are discussed. DEI relied on the end-use intensities provided by EIA, which incorporates both short-term and long-term trends. No additional adjustments were made to the EIA inputs.
2. *Cost Assumptions for Renewable Energy and Battery Storage Resources*: DEI responded the 2024 NREL Annual Technology Baseline (ATB) capital costs is based on data from the first quarter of 2023, the most recent available historical data at the time the report was prepared. The EIA's 2023 Annual Energy Outlook is based on even older information. That during periods of rapid change and volatility such as the industry is currently experiencing, considerable changes can occur even as a report is being developed. DEI addressed this challenge in the IRP by benchmarking cost estimates against bids received in the 2024 RFP.

Director's Comments

Changes in customer choices regarding heating and cooling appliances are part of the larger changes impacting load forecasts. Fortunately, the impact of HVAC choices accrues over time, allowing these changes to be accounted for in future IRP processes.

Citizens Action Coalition of Indiana, Earthjustice, Solar United Neighbors, Environmental Law & Policy Center, and Vote Solar (Joint Commenters)

Joint Commenters focused on providing recommendations to optimize the distribution grid and incentivize further customer adoption of DERs, like solar and batteries, and grid-enhancing technologies (GETs), like power flow controllers and dynamic line ratings.

Inclusion of Distributed Energy Resources in Its Modeling Process

Joint Commenters recommend the inclusion of DERs (rooftop solar and battery storage), as selectable in the capacity expansion model. They suggest that DERs should be treated as supply-side resources to unlock their full value for grid reliability, cost savings, and environmental benefits.

Customer Incentives for DER Adoption

Joint Commenters indicate that DERs bring cost reductions for customers, citing the Lawrence Berkeley National Lab (LBNL) report "*Indiana 21st Century Energy Policy: Emerging Technologies on the Electricity Distribution System Impact on Rates, Reliability, and Resilience.*" Joint Commenters

recommend creating programs to incentivize customers to adopt DERs, such as upfront financial incentives and fair compensation for energy exports.

Enhanced Distribution System Planning

The comments highlight the need for better integration of distribution-level planning into the IRP process. This includes setting DER deployment targets, improving forecasting, and leveraging non-wires alternatives (NWAs) to optimize the grid for increased DER adoption.

Grid Enhancing Technologies

Joint Commenters advocate for deploying technologies like Dynamic Line Ratings and advanced power flow controls to improve transmission system efficiency, reliability, and cost-effectiveness. These technologies can address near-term transmission bottlenecks and hedge against uncertain load growth forecasts.

Response of DEI

The Joint Commenters recommend that BTM solar be made selectable in the capacity expansion model. DEI responds that adding an additional selectable resource that is very similar to a resource type already represented in the model (utility-scale solar) would complicate the analysis and increase model run times without adding material value. The small scale of rooftop solar combined with the complexity of installing a rooftop system make BTM solar more expensive on a \$/kW basis than large, transmission-connected systems. Also, rooftop systems cannot be optimized for maximum output to the extent possible with large-scale, ground-mounted systems, and therefore rooftop solar has a lower capacity factor than utility scale solar. According to DEI, it would not be reasonable to add complexity to the IRP modeling by introducing a resource type that was known in advance to underperform a resource already available for model selection.

Joint Commenters argue that distributed energy resources lower costs for all customers, citing the LBNL report prepared in 2020 for the 21st Century Energy Policy Development Task Force. DEI notes the report appears to have evaluated only the potential costs and benefits of distributed resources to the rest of the system, without accounting for the costs to deploy the distributed resources. Also, the LBNL report did not compare the relative benefits of distributed and utility-scale resources, yet it did conclude that most savings from distributed solar accrue to the generation system, while distribution system costs increase slightly.

Director's Comments

The Director agrees with the Joint Commenters that DEI must increase the focus on distribution planning as an important component in the IRP process. There are steps in the movement to fully integrated distribution system planning, and DEI needs to start this process. The specific steps and the speed of implementation require judgment and discussion with stakeholders. In general, transmission and distribution capital investments are key drivers of increasing costs, and it is important that everyone better understands how transmission and distribution (T&D) investments fit into the broader choices to provide reliable and economic service consistent with the Five Pillars.

The Director recognizes this is an expansion of the planning process involving a broad stakeholder base and will be staff- and time-intensive. Education will be critical as it has been for the bulk power IRP process. Nevertheless, the potential benefits of a reasonable movement in this direction should offset the near-term growing pains.

Clean Grid Alliance (GCA)

The Clean Grid Alliance (CGA) provided detailed comments on DEI's 2024 IRP, expressing concerns about the Preferred Resource Portfolio (Blend 2) and its shortcomings in transitioning to a carbon-free energy system. CGA urges DEI to adopt a more aggressive and balanced approach to renewable energy and storage development, reduce reliance on natural gas, and improve modeling practices to better align with industry's best practices. Key points from CGA's comments are listed below.

Insufficient Renewable Additions

CGA criticizes the scale of renewable and storage resource additions as well as the timing of them, with most planned for the late 2030s and 2040s. This delay, the CGA suggests, increases reliance on market purchases during the 2030s and risks missing out on federal tax credits that may phase out earlier.

Underutilization of Energy Storage

The Preferred Plan's 400 MW of energy storage is viewed as inadequate by CGA. Stakeholders note that DEI did not explore long-duration energy storage (LDES) resources, as well as missed opportunities to explore co-located, hybrid, replacement, or surplus storage opportunities, including siting them at retiring thermal plants.

Overreliance on Natural Gas

CGA expresses concern with the plan to add 2,876 MW of natural gas capacity at Cayuga and Gibson Stations by 2032, citing risks such as fuel price volatility, supply chain challenges, performance during winter storms, and regulatory uncertainties. They recommend prioritizing renewables and storage instead.

Modeling and Cost Assumptions

CGA criticizes DEI's modeling for not adhering to best practices, particularly in its limited consideration of diverse storage technologies and lack of transparency in cost assumptions. They recommend comparing internal cost projections with publicly available data for greater accountability.

Short-Term Action Plan Recommendations from CGA including the following:

- Increasing renewable capacity and reducing new gas capacity.
- Adding storage capacity to planned and existing generating units.
- Deploying LDES resources strategically; issue RFPs specifically for emerging LDES technologies. Initiate pilot or demonstration projects to gain experience with LDES and prepare for future integration.
- Mitigating risks related to the Capacity Import Limit (CIL) for MISO Local Resource Zone (LRZ) 6. CGA advocates for MISO to redefine LRZ boundaries to better align with transmission constraints and improve investment signals. CGA suggests Duke should prepare for potential reductions in Indiana's CIL by boosting co-located storage capacity.

Comparisons with Other Utilities

CGA highlights more ambitious clean energy plans presented by utilities like Ameren Missouri and the Northern Indiana Public Service Co, LLC., emphasizing that DEI's approach lags regional peers.

Response of DEI

1. *Scale and Timing of Renewable and Storage Resource Additions*: DEI states that CGA provides no analysis of costs and benefits to support the position that more additions of these types of resources earlier in the planning period would be an improvement over the Preferred Portfolio with respect to the planning objectives.
2. *RFPs should be Open to Wind, Solar, and both 4-hour and Long-Duration Storage*: DEI notes its ongoing resource procurement was discussed several times during the stakeholder process. That procurement was open to all resource types, even allowing wind resources outside of the company's MISO zone. DEI invited CGA to actively participate in the stakeholder process for the next IRP.
3. *Long-Duration Energy Storage should have been included as a Selectable Resource in the Reference Planning Scenario*: DEI responded that LDES technologies remain largely pre-commercial and it would not have been reasonable to include them in the Reference scenario. DEI will reassess the technology in the next IRP.
4. *Use of Levelized Cost of Electricity to Compare Resource Costs*: DEI notes that CGA stated that the overall cost-competitiveness of wind, solar, and storage is not reflected in the IRP, in which only overnight capital costs by technology type are compared. DEI responded that CGA's concerns are unfounded. The IRP is based on thorough and robust capacity expansion and production cost analysis which incorporates resource capital costs, operating costs, fuel costs, and a wide range of other factors. Levelized Cost of Electricity (LCOE) is an energy-only metric that fails to account for other essential factors crucial to resource selection, most importantly time-of-use and capacity value. Adding "firming" costs to the LCOE is no substitute for full resource planning analytics of the kind supporting the IRP.

Director's Comments

CGA's recommendations to improve the short-term action plan are calls for the DEI IRP to be redone. After all, the short-term action plan should be based on near-term actions identified in the IRP's preferred portfolio which reasonably accounts for risks and uncertainties. If that is not the case, then the concept of developing a long-term resource plan is without purpose. Ideally, the near-term resource actions are reasonable across a range of potential futures without locking in a path that limits the ability to adjust as circumstances warrant over time.

It is expected that DEI will make effective use of RFPs to benchmark its resource options evaluated in future IRP processes. This will include long-term energy storage. The Director expects that all utilities will improve their analysis of energy storage resource options as a part of their ongoing actions to improve IRP methods and analysis.

Energy Futures Group (EFG) on Behalf of Citizens Action Coalition of Indiana, Earthjustice, Solar United Neighbors, and Vote Solar

Stakeholder Workshop and Material Provided to Stakeholders

EFG appreciated the improved stakeholder process, allowing for more meaningful collaboration and dialogue around modeling inputs. However, they felt there is still room for improvement, citing an example where DEI claimed they were unable to provide workbooks supporting firm gas transportation contracts even under a non-disclosure agreement. EFG was concerned about the lack of access to this important modeling input, given that DEI's resource options include new combined cycle (CC) gas units and other resources options dependent on gas transportation.

EnCompass Modeling

According to EFG, across the country there has been a widening gap between the assumed costs of generic new CC units in IRPs compared to the costs in Certificate for Public Convenience and Necessity (CPCN) for new CCs. EFG believes the CC capital cost assumptions used in the IRP were unreasonably low. They cited the IRP of Kentucky Utilities and Louisville Gas and Electric that recently filed a CPCN for a new CC, which contained a significantly higher capital cost assumption for a new CC unit.

EFG claims that it does not appear that DEI tested the CC replacement at the Cayuga site under a higher capital cost sensitivity since the Cayuga CC units were assumed to be included in the plan. They believe DEI's preferred plan should have been re-optimized to reflect higher capital costs assumptions to test the CC replacement at Cayuga.

EFG found DEI's modeling of small modular reactor (SMR) capital costs and learning curve to be unrealistic. They believe the application of the learning rate in the analysis is flawed as it results in cost reductions before DEI has the benefit of constructing an SMR. They note that DEI's preferred portfolio does not include any SMR resources.

EFG highlights the potential savings for ratepayers by converting the Edwardsport plant to gas only operations by 2028 or earlier. DEI claimed that running Edwardsport, with dual fuel capabilities, offered valuable flexibility, but EFG contends that there has been no attempt to quantify this value. They questioned the actual operational flexibility provided by a dual fuel system and claimed that evidence in DEI's last rate case had established that Edwardsport has become uneconomic. They go on to emphasize the potential savings associated with converting to natural gas only by 2028. EFG urges further scrutiny and adjustments for DEI's modeling of resource availability and build limits for renewable resources. EFG points out and appreciates that the annual build limits for solar, storage, and wind resources were slightly relaxed starting in 2032, but recommended further relaxation.

In all of its modeling runs, DEI removes the power purchase agreement (PPA) for the Benton County wind farm in 2028 when it expires. EFG says it is unclear whether DEI evaluated repowering the project. They note that repowering the project could be more cost effective than building a new wind resource and that while a DEI does not own the project, if its life is extended, DEI would be an obvious candidate to take ownership.

Portfolio Scorecard Metrics

EFG expresses concern regarding the Execution Risk metric. They state that the metric does not capture the execution risk and construction timeframes that may be unique to each technology

type. EFG suggests that DEI replace the single metric approach with a timeline that provides a sense of the importance of deciding on a particular resource and the risks of the projected online date. EFG suggests that DEI's evaluation of resource diversity in the resiliency metric could benefit from alternative calculations and be based on the number of unique generators or the number of different fuel types, for example.

EFG believes DEI's load forecast assumptions may overstate EV and large loads impact on load. They believe that EVs and large loads should be removed from the projected forecast and modeled separately. EVs should be modeled to account for different managed charging scenarios and large loads as a negative generating unit.

EFG notes that in the SERVVM modeling process DEI assumed it would not interact with the MISO market. They suggest DEI model a representation of MISO's market availability. This could be accomplished through developing a distribution of market imports based on historical data which would allow SERVVM to capture the risks of market access.

EFG expresses concerns that DEI underestimated the forced outage rates for CC units, with DEI's assumed outage rate lower than the seasonal class average CC. They also do not believe DEI has incorporated additional forced outages associated with weather into the SERVVM models. They state that DEI should continue to evaluate the need for a cold weather outage adder as more gas resources are added to the system.

Demand Side Resources

Energy Efficiency

EFG said DEI and its MPS contractor, Resource Innovations, were generally receptive to input during the energy efficiency MPS process. However, the number of opportunities for stakeholder engagement were more limited compared to other Indiana utilities' processes. Additionally, as the process advanced, RI stopped providing formal responses to comments.

According to EFG, RI was responsive to some of the Citizens Action Coalition's (CACs) concerns about energy efficiency measures, but not responsive to feedback about the factors influencing the technical potential equation. CAC disagreed with the metric used by RI to measure square footage of single-family homes. CAC recommended increasing the square footage metric which would increase the savings potential of energy efficiency measures in which the metric was included.

EFG said the oversight board (OSB) had no opportunity for input on the construction of the energy efficiency bundles or the EE levelized cost calculation. They also say that CAC's recommendation to create bundles by sector, cost, and time vintage, and to treat income-qualified separately was not addressed.

While the IRP preferred portfolio includes bundles 1 through 5 for energy efficiency, no "high" bundles were selected. EFG claims that this is likely due to construction of the "High Incentive" MPS scenario, where the incentives were doubled to a 75% incremental cost cap. EFG believes that incentives could have been increased more efficiently to improve the chance of more bundles being selected in the preferred portfolio.

Demand Response

EFG claims that DEI's demand response MPS fell short in fostering meaningful stakeholder participation and incorporating feedback. Throughout the process, schedules were delayed and

communication was insufficient. Modeling was finalized without addressing stakeholder concerns. The lack of transparency and collaboration undermined trust in the process and highlighted significant gaps in stakeholder engagement practices, according to EFG.

EFG took issue with RI excluding peak time rebates (PTR) and time of use (TOU) products from the demand side resource MPS because RI classified them as permanent load shifting and not a dispatchable/callable resource. EFG argues that PTR can be classified as callable resource and cites studies recognizing PTR's resource potential as a capacity resource. EFG also disagrees that dynamic pricing products like PTR and TOU should be excluded from consideration of an assessment of potential because RI classifies them as a permanent load shifting approaches. They argue demand resource studies regularly include dynamic rate programs regardless of whether they are classified as demand response and not including them in the analysis results in an underestimation of the true capacity savings potential.

EFG felt the methodology behind the demand response potential lacked clarity. They found the reduction of approximately 86-96% from economic to achievable potential to be more extreme than anticipated.

Response of DEI

1. *DSM Process and Project Scheduling:* RI and DEI engaged the DSM Oversight Board throughout the development of the MPS, seeking feedback on the schedule, methodology, and draft results. The engagement began with a kickoff meeting that detailed the project milestones and study topics where RI would seek OSB participant input. Comments were received from OSB participants, but no objections were raised to the type or frequency of planned stakeholder engagement.

MPS study materials were provided to the OSB participants as completed, most often in draft form, specifically to collect OSB participant feedback. RI maintained consistent communication, exchanging project methods, data, and interim files with OSB participants, on average, approximately every nine business days. The communications included noting when project tasks and coordination were taking longer than anticipated.

Joint Commenters, through the EFG, claim they were given only three opportunities to comment on the MPS due to there being only three OSB stakeholder meetings specifically addressing the topic. DEI says this assertion is factually wrong and ignores the multiple opportunities for engagement through the OSB process and the broader IRP stakeholder meetings.

The MPS development process did, in fact, utilize monthly stakeholder meetings to allow numerous opportunities for review and input.

2. *Energy Efficiency:* EFG recommended that income-qualified (IQ) measures should be bundled separately, since they are not subject to cost-effectiveness screening and should be modeled as a forced-in resource in the IRP. DEI responded that the IQ measures were selected as part of the base case in the IRP Preferred Portfolio indicating those measures do not unduly burden program level cost-effectiveness. The IQ measures were ultimately included in the portfolio regardless of whether they were modeled as a selectable resource or a forced-in resource.

With respect to expanding the number of EE bundles, DEI noted there are inherent tradeoffs associated with model processing time and the number of discrete bundles input to the model. DEI will consider how to enhance specificity of the bundles while minimizing processing time in the IRP modeling.

Regarding EE levelized cost, the EE bundles and the associated levelized costs were based on savings at the generator using a loss factor of 7.14%. The levelized costs were also calculated from savings over the life of the measures in each bundle, so they were not constrained to the planning period. T&D benefits were recognized in the MPS cost-effectiveness evaluations, not directly in the calculation of EE levelized costs.

3. *Cost Estimates for CCs and SMRs:* DEI notes that EFG asserts the forecasted capital costs for new CCs in the IRP are unreasonably low and inconsistent with the current market for such facilities. DEI developed cost projections for CCs using a combination of actual RFP bids and insights from DEI's own subject matter experts. DEI also disagrees that cost estimates for a CC in an IRP recently filed in Kentucky are more appropriate than estimates informed by DEI's own RFP. DEI recognizes that resource costs fluctuate, sometimes rapidly, throughout the IRP development process. This is why DEI included CC and CT capital costs in sensitivity analysis conducted in the IRP.

EFG contends that the equivalent forced outage rate (EFOR) assumption for new CCs used in the IRP is overly optimistic. EFG compares the EFOR assumption used in the IRP to the class average for existing MISO units and suggests adding additional performance penalties in cold weather for CCs. DEI responds that it intends to construct best-in-class advanced CC units and, therefore, the EFOR assumptions used in the IRP are appropriate.

DEI recognizes that there is tremendous uncertainty regarding the ultimate cost of developing new nuclear resources and will continue to evaluate and update its forecasts in future planning cycles.

4. *Stochastic Analysis of Market Exposure and System Reliability:* DEI recognizes that improving the precision of the SERVIM stochastic load estimates could be useful and, as part of its continual improvement in modeling capabilities, intends for future model updates to include discrete load categories for which EI's load forecast includes separate hourly profiles, provided sufficient data are available to support the more sophisticated analysis.

A core assumption of DEI's reliability analysis is restricting the modeling to focus on the ability of DEI resources to meet load. The ultimate purpose of stochastic reliability modeling is to ensure the DEI's future resource portfolios contribute their fair share to the MISO market and do not place undue burden on the rest of the system.

DEI disagrees with EFG's recommendation to incorporate in the analysis of interaction with the MISO market a probabilistic import availability approach utilized by MISO in its near-term probabilistic analyses, such as the MISO's 2024/2025 Loss of Load Expectation (LOLE) study. First, including market interaction misunderstands the purpose of the reliability modeling, which is to gauge the alignment of resource outputs/availability with DEI's customer load and estimate the degree of market reliance; the purpose is not to identify periods of potential overall market shortfall. Second, MISO may feel it is appropriate to utilize recent historical data to estimate import capability for the market as a whole for the next LOLE study, but this history may not map accurately onto a future market whose

internal transfer capabilities may experience fundamental changes as the underlying resource mix evolves.

EFG recommends additional analysis of “reliance” on economic market energy purchases. DEI notes this is not reliance in the sense of energy adequacy. Rather, it is economic market participation to the benefit of customers. However, DEI recognizes the cost risk and potential for reliability risk associated with allowing the market to provide a substantial portion of the energy used to serve customers in the EnCompass model. This is why DEI conducted a thorough stochastic analysis of the cost and reliability risk associated with this level of energy market participation.

5. *Execution Risk*: Execution risk or any other measure must be represented as a single number for scorecard purposes, but it could be helpful to provide additional detail elsewhere in the IRP. However, it must be recognized in the context of generic units used in resource planning that certain information necessary to make a useful project plan is not available at the long-term resource planning stage.

Director’s Comments

DEI’s use of the SERVM model is a significant improvement to the IRP planning process. Both DEI and EFG believe that improvements can be made to use the model more effectively. They might disagree on specific details, but the point is that use of SERVM is an improvement to the utility IRP process with opportunities to use the model more effectively going forward. As with all things IRP, much depends on the availability of data.

The discussion of EE and DR by EFG and DEI’s response shows there is more disagreement about the sharing of information (and the willingness to listen going both ways) than one would hope. There is evidence of different perceptions by DEI and EFG of the stakeholder process for EE and DR. This seems to be more so the case in this area than in other aspects of the IRP process. Perhaps it is because of the extensive data preparation and analysis necessary to include EE and DR bundles as resource options in the IRP optimization process. The complexity necessitates the application of much judgment, and DEI and EFG have different takes on the application of this judgment. These differences don’t bode well as the IRP process continues to become more complex, especially with a move to include more distribution planning as an example.

Energy Matters Community Coalition (EMCC)

EMCC submitted a report prepared by Synapse Energy Economics, Inc. (Synapse) titled *“Considerations for Future Modeling of a Deep Decarbonization and Electrification Scenario.”*

EMCC offers the following recommendations for consideration in the next iteration of the Deep Decarbonization and Electrification (DDRE) scenario:

1. In the next IRP, DEI should estimate the amount of DERs that could be included within its service territory by 2050 and report these findings with the DDRE scenario results. The rationale is that not all new resources need to be utility-scale, supply-side resources. Also,

DERs help diversify the resource portfolio with fewer siting, permitting and transmission requirements.

2. DEI should include an EV load shape that reflects the benefits of managed charging, including substantially reduced peak demand from EVs. DEI should also evaluate the potential value to customers of programs that facilitate charging EVs at non-peak times through workplace charging and delayed home charging.
3. DEI should include a more precise estimate of industrial electrification potential based on the industrial facilities located in its service territory that could be electrified within the planning timeframe.
4. Before procuring new resources, DEI should evaluate the risk of procuring its preferred resources by 2032 if strong greenhouse gas (GHG) policy is then enacted. It does not appear that DEI has evaluated a scenario where it proceeds with procuring 3 GW of gas-fired resources by 2032, and then strong GHG policy is enacted. Such a scenario is plausible, and DEI should evaluate the risk of such a scenario before it makes a large investment in new emitting resources.
5. DEI should consider adding more near-term renewable generation to its portfolio as a hedge to reduce risks for customers caused by exposure to both GHG regulatory risk and natural gas price risk.
6. DEI should evaluate the potential to locate non-emitting resources near retiring coal plants utilizing existing interconnection rights. This is in response to DEI including an interconnection cost adder for new resources except for new combined-cycle and CT units added before 2032 because these facilities are assumed to interconnect at the sites of retiring coal plants under MISO's generation replacement process.

Response of DEI

In response to EMCC's comments that DEI failed to adequately account for climate risk or GHG regulatory risk, DEI explained that throughout the IRP planning process that improving environmental sustainability was a key planning objective. Also, DEI stated that GHG regulation was a major consideration in developing the generation strategies and broader analytical framework for the IRP.

Responding to the argument that additional resource types should have been allowed in the planning process to benefit from generator replacement, DEI noted that the potential for transmission network upgrade cost increases when the characteristics of the replacement resource differ from those of the resource being replaced.

Director's Comments

The Director agrees that it would be a helpful exercise to evaluate the implications of developing resources under one scenario when unexpectedly halfway through the planning period another policy circumstance is implemented. The nature of the world is that there are sudden unexpected changes that will have a large impact and modify resource choices going forward. What are the implications for the resource choices made under the initial planning assumptions when suddenly and unexpectedly confronted with an enduring policy change as an example; essentially what are the implications when you have one scenario for the first 10 years of the planning period and suddenly a new planning environment comes into existence. The Director recognizes

the difficulty in performing this type of analysis. The Director is not aware that this type of analysis has been done.

The Director agrees that there is room for improvement in the consideration of flexible load (broadly defined) and the various options to implement greater load flexibility in the planning and operational environments. Indiana utilities should increasingly see load as something that can be intentionally modified. Intentional actions to make load more flexible is a resource option to supplement more traditional consideration of supply-side resources.

Office of Utility Consumer Counselor (OUCC)

The OUCC identified several areas where they offered observations and recommendations.

Modeling Process and Scorecard

The OUCC acknowledged DEI used the Strategic Energy Risk Valuation Model to evaluate portfolio performance under real-world uncertainties, which provided power price variability in market purchases, the inclusion of CO₂ emissions, and forecasted operating costs are improvements from previous DEI IRPs.

The OUCC said the IRP scorecard comprehensively evaluated the Five Pillars using 15 different metrics. The scorecard enhanced the evaluation of each portfolio over the 20-year planning period. However, it was noted that the “Stability” pillar is not measured quantitatively.

Portfolio Diversity

The OUCC states that most portfolios are too similar, with differences driven mainly by retirement timing and Duke’s choice of Portfolio Blend 2 as the preferred portfolio was not transparent since the PVRR and customer bill impact did not show significant variation among the portfolios. The OUCC recommends testing a wider mix of resources, including using combustion turbine peakers with renewables instead of combined cycle gas turbines (CCGTs).

The OUCC would like to see clearer comparisons of resource options, comparing the cost and benefits of converting coal units to gas versus co-firing with natural gas or building new combined-cycle plants.

Load Forecasting

The OUCC argues that Duke’s EV adoption forecasts are overly optimistic. The OUCC recommends Duke account for potential changes to the existing policies and to incorporate more regionally specific data related to local barriers and urban-rural adoption disparities.

The OUCC criticizes DEI for assuming a linear relationship between explanatory variables and projected BTM Solar adoption. Use of a linear model means growth in BTM Solar adoption may be underestimated in the face of rising energy costs and trending downward solar panel costs. The OUCC suggests that greater BTM adoption could offset the significant projected load growth from EVs.

The OUCC points to a likely unit error in DEI’s economic development load adjustment (Table D-5; MWh vs. GWh) and suggests that it is unclear how these additions contribute to the system peak.

Emerging Load Growth

The OUCC expressed concern that DEI did not adequately capture potential load growth from hyper-scalers or large load customers. They suggested that DEI should have modeled additional data center demand beyond the 500 MW new data center load sensitivity in 500 MW to 1,000 MW increments up to a total incremental load of 5,000 MW.

Historical Data Discrepancy

OUCC points to inconsistencies in historical load data compared to the 2021 IRP, which should not change (Table D-12: Historical Actual System Peak, Generation, and Load Factor).

Analysis of The Five Pillars

Reliability, Resiliency & Stability

The SERV model allowed DEI to assess how its portfolio would perform under a range of weather patterns, unit availability, economic load forecast errors, and hourly dispatch availability. DEI was able to estimate how much customer demand would not be served if DEI's system was isolated from the wider MISO market. The intent of the analysis was to determine how much DEI's portfolio relied on market purchases and whether it makes disproportionate demands on the wider MISO system. The OUCC saw this analysis as a significant improvement.

The OUCC recommends that as the DEI resource portfolio includes significant new natural gas fired generation it is important to account for the risk of natural gas supply disruptions during cold weather events.

Affordability

Affordability metrics (PVRR and Bill CAGR) are similar across portfolios. However, the OUCC notes that Blend 1, where Cayuga Units 1 and 2 would be converted to natural gas, has the second lowest PVRR, the second lowest bill CAGR in 2030, and the lowest bill CAGR in 2035.

The OUCC presented a table showing the projected base rate cost increase until 2035 of a 1,000-kWh electric bill for DEI's preferred portfolio (Blend 2). The preferred Blend 2 portfolio showed potential for base rate increases totaling over 70 percent within the next 10 years.

Environmental Sustainability

The OUCC calls for more details on unit-by-unit environmental compliance costs. More specifically, the OUCC recommended that DEI provide clearer details on the costs associated with Clean Water Act Sections 316(a) and (b) compliance for both Cayuga Units 1 and 2 to remain operating as steam units. The OUCC appreciates that Duke based its assessment of CO₂ reductions using 2025 as CO₂ baseline instead of a past year, such as 2005. Using 2025 as the benchmark more clearly shows the attributable CO₂ emission reduction for each portfolio.

Response of DEI

DEI responded to several points made by the OUCC:

1. *Portfolio Diversity*: According to DEI, there are several reasons why Blend 2 is the more reasonable and prudent choice instead of Blend 1. The primary driver of the cost difference between Blend 1 and Blend 2 is the difference in projected retirement dates for the converted and co-fired units. In Blend 2, the co-fired Gibson units retire by 2039 and must be replaced. To support this retirement, 1,150 MW of solar, 1,600 MW of wind, and 550 MW

of battery energy storage are added to the Blend 2 portfolio between 2036 and the beginning of 2039. In Blend 1, no solar or battery storage capacity is added during the period and total wind additions are lower at 1,050 MW.

Blend 1 is predicated on the assumption that it is reasonable and prudent to expect the existing Cayuga units, which would enter their seventh decade of operation in the 2030s, to operate reliably into the mid-2040s. Blend 1 also carries unacceptable execution risk. Blend 1 calls for the simultaneous retirement of Gibson units 1-4. The simultaneous construction of two 1,438 MW CC units at the same site, as well as the necessary work to secure sufficient fuel supply at the site in that timeframe, presents a substantial hurdle, making Blend 1 a much more challenging plan to execute than Blend 2.

DEI noted that the OUCC suggested that DEI considered only new CC resources to replace retiring generation. DEI responded that it is important to recall that every resource type described in the IRP is “considered,” and that any of the resource types available for model selection could have been selected to replace retiring generation. The fact that CTs were not selected in any of the candidate resource portfolios is not an indication that the resource was not considered.

2. *Load Forecast:* DEI noted that the OUCC expressed concern that DEI did not consider a sufficiently “high” high load forecast sensitivity, suggesting that additional data center load should have been included beyond the 500 MW of hypothetical data center modeled by DEI. DEI responded that the high load case also includes an increased proportion of all economic development projects, higher EV adoption, and an optimistic economic forecast. DEI also notes that any planning insight that might be gained through modeling of several additional load sensitivities must be considered in the context of an IRP which is already broad and complex.

DEI acknowledged the OUCC’s concerns that the forecasts for EV and BTM solar adoption may be overly simplistic. DEI stated it would continue to refine its forecasting process as more data becomes available. DEI noted that scenario analysis is a useful tool for evaluating potential futures, and that DEI evaluated EV and BTM solar adoption rates above and below base case projections in the IRP.

Director’s Comments

The OUCC’s comments on load forecasting highlight the importance of significant renewed annual load growth and its uncertainty after years of relative stability. The Director thinks a critical factor is the potential changes in the 8,760 hourly load shape different types of load growth might cause. Hourly loads for different types of new loads need to be closely reviewed for potential flexibility and how these changes in hourly loads might impact the performance of different resource portfolios. This highlights how resource planning needs to increasingly account for operational realities. Changing resource characteristics and changing load characteristics means that real-time operational considerations need to increasingly be accounted for in long-term resource planning studies.

Reliable Energy

Reliable Energy (REI) submitted comments urging the need to revise the IRP considering major regulatory shifts under President Trump's administration. REI believes the IRP should prioritize keeping coal plants online to meet anticipated load growth and avoid premature closures.

Potential Policy Changes

REI highlights the potential impacts from President Trump's Energy Emergency Declaration and related executive actions. These measures could restrict coal plant retirements, reduce costs associated with environmental regulations, and encourage continued fossil fuel generation. REI also notes that proposals such as a moratorium on new wind development and revisions to clean energy tax credits may affect renewable energy economics and reshape electricity demand forecasts.

Criticism of Preferred Portfolio

REI strongly criticized DEI's Preferred Portfolio, which assumes compliance with the EPA's Clean Air Act, Section 111 and calls for retiring coal plants and transitioning to natural gas and renewables. REI believes the "No 111 Case," which assumes the Section 111 rule is overturned, is more cost-effective and reliable, arguing maintaining baseload coal-fired units during a period of capacity constraints is "the cheapest and most reliable option for customers." REI also expressed concern that the No 111 scenario fails to account for potential rollbacks of other environmental rules, including those related to Coal Combustion Residuals, Effluent Limitations Guidelines, Mercury and Air Toxics Standards, and the Good Neighbor Plan.

Coal Plant Retirement

REI argues that delaying retirements could reduce near-term capacity needs, provide time for advanced technologies to mature, and help avoid stranded costs associated with new natural gas investments.

REI recommends that Duke:

- Update modeling to reflect regulatory changes and proposed policies.
- Revise IRP conclusions to align with the new regulatory landscape.
- Refrain from seeking a Certificate of Public Convenience and Necessity for any major investments in coal plant closures or refueling until regulatory requirements are clearer.
- Refine analyses of the Five Pillars, with particular emphasis on expanding the Affordability pillar to include annual ratepayer impacts for at least a 10-year period.
- Explore opportunities to sell coal plants to third parties before retiring them.

Response of DEI

Regarding Reliable Energy's point that delaying retirement of existing units can allow time for technology to mature and for new resource options to become viable, DEI notes these potential benefits must be weighed against the age, condition, compliance requirements, economic competitiveness, and other risks and challenges associated with the existing units in question. *(See DEI Reply comments, p. 3)*

Responding to Reliable Energy's preference for affordability calculations employing a depreciating rate base methodology, DEI stated that it included two affordability metrics in the scorecard: PVRR and customer bill impact expressed as a projected compound annual growth rate. That these two metrics serve different purposes. PVRR provides an estimate of the total cost of a given portfolio over the planning horizon, while customer bill impact provides a snapshot of cost impact to customers at a given point in time.

For purposes of the PVRR calculation, the capital cost of new resources is included using the economic carrying charge levelized over the life of the resource in question, while the bill impact calculation is based on depreciating rate base methodology. The PVRR of new resource capital costs will be identical under the two approaches over the course of the life of the asset. However, when the asset lives of new resources extend beyond the end of the 20-year planning period, it is crucial for new resource capital costs to be levelized for purposes of resource selection and PVRR calculation.

A depreciating rate base approach front-loads revenue requirements associated with new resource capital costs, making new resources less economical early in their lives (higher annual revenue requirements) and more economically attractive late in their lives (lower annual revenue requirements). This would be fine if the entire useful life of each resource was captured within the planning period but introduces bias against new resources with lives extending beyond the planning horizon.

The PVRR metric does not capture the timing of rate recovery or the impact on customers in any given year. According to DEI, this is why they included the customer bill CAGR as a supplement to the PVRR metric. Balancing total long-term cost and near-term impact on customers was an important consideration in the IRP.

DEI argues that the projected bill impact should not determine customer affordability. The bill impact estimate, which employs the depreciating rate base methodology, can vary considerably by year and is subject to significant bias against resources added in or near the year for which the calculation is performed. PVRR over the full 20-year horizon required by the Commission's IRP rules better captures the impact of potential new investments on future generations than would analysis over a shorter period.

Director's Comments

The Director acknowledges that the planning environment is complicated and characterized by extensive uncertainty, especially about federal energy policy. It is to be expected that DEI will have to evaluate whether, when, and how to update its IRP analysis.

As stated above, the Director thinks DEI did an excellent job addressing risks and uncertainties through a well-developed IRP and a thorough discussion at every step of the analysis. Uncertainty exists because the future is not knowable. DEI implemented an IRP structure and methodology that fully recognized this circumstance. Much judgment is required and cannot be avoided. Judgment is required when developing methodology, data, assumptions, and interpreting results. Sound use of scenarios, sensitivity analysis, and stochastic analysis informs near-term resource choices within this unknowable future. As circumstances change, then judgments and choices may change. This is why planning is a never-ending process.

Sierra Club

The Sierra Club raised concerns about the preferred portfolio, modelling assumptions, and Duke's decisions regarding its fossil-fueled units.

Preferred Portfolio Critique

The Sierra Club explains that Duke's preferred portfolio (Blend 2) is both more costly and riskier than Blend 1, which calls for converting the Cayuga plant to gas rather than building a new gas plant. According to Duke's own modeling, Blend 1 saves customers \$100 million in PVRR in the reference scenario; according to the Sierra Club's calculations, the savings range from \$519 million to \$1.018 billion across the seven portfolios in the reference case. Blend 1 is also a cleaner alternative to Duke's preferred plan.

The Sierra Club further argues that Blend 1 reduces near- and medium-term rate impacts by avoiding Duke's understated cost recovery method, which assumes levelized costs instead of rate-based assets. The group criticizes Duke for relying on the "carrying cost" of new resource builds rather than the rate-base method for capital costs used by EnCompass.

The Sierra Club also suggests that Blend 1 mitigates risks—including market reliance, reliability, and execution risks—and performs better under extreme weather conditions.

Edwardsport Conversion

The Sierra Club urges Duke to convert the Edwardsport plant to gas by 2028 instead of 2030, noting that an earlier conversion is both more cost-effective and reduces carbon emissions. A 2028 conversion would reduce costs by approximately \$100 million and cut carbon emissions by 3.8 million tons in 2028 and 2029. By delaying conversion, Duke continues to burden ratepayers with high costs.

Carbon Capture and Storage (CCS) at Edwardsport

The Sierra Club opposes Duke's proposal to add CCS at Edwardsport in 2032, citing high costs, uncertain performance, and the risk of prolonging coal operations. The group argues that Duke's decision is based on overly optimistic assumptions and would be a poor investment, given the plant's existing cost burdens.

Modeling Assumptions

The Sierra Club criticizes Duke's overly optimistic assumptions regarding the efficiency and fuel costs of the Gibson and Cayuga coal units, which are inconsistent with historical performance. Modeling assumes capacity factors nearly twice the historical average. Heat rates are projected to be 8-13% better than historical records, with no justification—Sierra Club calls these assumptions unrealistic.

Lastly, stakeholders flagged that Duke assumes unreasonably high costs for clean energy resources. For example, solar and wind costs are modeled at about 35% and 29% higher, respectively, than the National Renewable Energy Laboratory's (NREL) mid-case forecast for 2030. Storage is also more expensive in the early years. These elevated cost assumptions tilt the model away from clean energy and toward gas infrastructure. The Sierra Club recommends that Duke model at least one scenario or sensitivity using lower capital costs for these clean energy resources.

The Sierra Club makes the following recommendations:

- Convert Edwardsport to gas by 2028 or earlier.
- Update modeling assumptions of the clean energy costs and coal units' performance.
- If Duke does not update its modeling, the Sierra Club recommends adopting the build-outs from Blend 1 but with Edwardsport's conversion in 2028.

Response of DEI

DEI argues there are several reasons why Blend 2 is the more reasonable and prudent choice.

"First, all existing coal-fired units at Gibson Station are retired in Blend 1, while the Cayuga units continue to operate. Whereas, in Blend 2, the Cayuga coal-fired units are retired along with Gibson units 3-5 while Gibson 1&2 continue to operate. Second, in Blend 1 the remaining steam units (Cayuga 1&2) are converted fully to natural gas fuel, while in Blend 2 the remaining steam units (Gibson 1&2) are modified to burn a blend of coal and gas. The co-fired Gibson units in Blend 2 are retired by the end of 2038, while the fully converted units in Blend 1 are assumed to run through the end of the study period." *(See DEI Reply comments, p.2)*

"The primary driver of the cost difference between Blend 1 and Blend 2 is the difference in projected retirement dates for the converted and co-fired units. In Blend 2, the co-fired Gibson units retire by 2039 and must be replaced. To support this retirement, 1,150 MW of solar, 1,600 MW of wind, and 550 MW of battery energy storage are added to the Blend 2 portfolio between 2036 and the beginning of 2039. In Blend 1, no solar or battery capacity is added during that period and total wind additions are lower, at 1,050 MW. Sierra Club comments that the lower amount of new build in Blend 1 results in cost savings, but Blend 1 is predicated on the assumption that it is reasonable and prudent to expect the existing Cayuga steam units, which would begin their seventh decade of service in the 2030s, to operate reliably into the mid-2040s. Earlier retirement of those units, the risk of which is not insignificant, would necessitate new build similar to that in Blend 2 and would likely eliminate the apparent cost savings offered by Blend 1." *(See DEI Reply comments, pgs. 2-3)*

"In addition to the substantial risk around any PVRR differential with Blend 2, Blend 1 also carries unacceptable execution risk. Blend 1 calls for the simultaneous retirement of Gibson units 1-4 by the beginning of 2032. This requires major replacement generation build out by that time, for which the expedited interconnection process associated with a generator replacement request ('GRR') for the Gibson units would be essential. The capacity expansion model selected two 2x1 combined cycle ("CC") generators to be in service by the beginning of 2032 for the Blend 1 portfolio to support the Gibson retirements. However, the simultaneous construction of two, 1,438 MW CC units at the same site, as well as the necessary work to secure sufficient fuel supply at that site in that timeframe, presents a substantial hurdle, making Blend 1 a much more challenging plan to execute than Blend 2. Blend 2 has an equivalent amount of new CC capacity (2,876 MW) by 2032, but the units are added in manageable stages and at two sites, with two 1x1 CCs at Cayuga and a single 2x1 CC at Gibson." *(See DEI Reply comments, p. 3)*

Regarding fuel switching Edwardsport by 2028 instead of 2030, DEI notes that Edwardsport is the newest and cleanest coal-fired unit on their system with a history of improving operations and

lowering costs. DEI also argues that the facility provides optionality and flexibility during this period of transition and uncertainty.

According to DEI, the resource capital cost forecasts are based on the most up-to-date cost data available from reputable sources, including Guidehouse, Burns & McDonnell, EPRI, NREL's Annual Technology Baseline, the EIA Annual Energy Outlook, Lazard's Levelized Cost of Energy estimates, and Wood McKenzie. DEI also benchmarked its cost forecasts against project cost data from bids submitted to the 2024 RFP.

DEI noted the data used in both the NREL ATB and the U.S. Department of Energy Annual Energy Outlook is out of date given the large cost fluctuations being seen in the market. The fluctuations seen in the market and the time lag from when data is collected and published by NREL and EIA make it especially important to benchmark cost estimates against recent market information reflected in RFPs.

Director's Comments

Sierra Club's comments highlight the importance of data inputs and assumptions in a complex and uncertain planning environment. It is important to understand where data comes from, how it is developed, and the inevitable time lags between collection and publication. Reliance on multiple data sources for resource cost estimates is important, but it is necessary to evaluate these data assumptions and sources against market-based information.

DEI's response on the reasons for the cost difference between Blend 1 and Blend 2 highlights the numerous considerations involved when comparing different resource portfolios. Numerous factors impact why costs differ and need to be fully considered when evaluating resource portfolios.