Draft Director's Report

For Duke Energy Indiana (DEI) 2021 Integrated Resource Plan

December 2, 2022

Dr. Bradley Borum
Director of Research, Policy, and Planning
on behalf of the Indiana Utility Regulatory Commission

CONTENTS

Draft Director's Report Applicable to DEI's 2021 Integrated Resource Plan and Planning Process

I. Purpose of IRPs

Duke Energy Indiana's (DEI's) 2021 Integrated Resource Plan (IRP) was submitted on Dec. 15, 2021. 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 IRP Director in the 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 IRP, 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.

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 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

DEI's 2018 IRP accelerated the retirement dates of its coal plants by an average of nine years. The 2021 IRP Preferred Portfolio accelerates coal plant retirements an average of four years compared to the 2018 IRP. The preferred plan includes a natural gas combined cycle plant and continued operation of the Edwardsport IGCC until 2035, along with increasing amounts of solar, wind, and battery storage resources.

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 2021 IRP included a couple of significant improvements compared to the 2018 IRP.

- DEI decided to use the EnCompass planning model. The model provides considerably more capability than the primary long-term resource planning model used by DEI in previous IRPs.
- DEI performed a fuller analysis of the Edwardsport IGCC. DEI's 2018 IRP was weakened by the failure to review the various operational options presented by Edwardsport. These options are continuing to operate primarily on coal, conversion to operate exclusively on natural gas, and retirement of the plant. These possibilities were evaluated by DEI in the current IRP.

Consistent with the issues discussed above, the Director's report will focus on four 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 (DERs); (3) Portfolio analysis and the consideration of risk and uncertainty on different resource portfolios; and (4) Public advisory process.

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. Forecasts of energy and peak demand are prepared each year. The general load forecast framework includes a national economic forecast, a service area economic forecast, and the electric load model.

According to DEI, independent forecasts for electric vehicle (EV) and solar (PV – rooftop solar distributed energy resources) are added to the "baseline" electric forecast. The EV and solar forecasts are generally added to the baseline forecast without modification.

High and low load forecasts were also developed. The low load forecast is approximately 1% below the baseline forecast, and the high forecast starts at 1% higher in 2021 and growing to a 6.1% increase in 2040.

DEI also began to analyze how a climate change scenario might impact the load forecast. This was done by including a measure of humidity to the weather data. DEI created a Temperature Humidity Index degree dataset from which a heating degree and cooling degree day dataset was created and used in the climate change analysis. Results showed no material impact on the load forecast.

Other inputs to the load forecast are rooftop solar generation and EV charging load. In the load forecast, the impact of rooftop solar and EVs on summer peak demand essentially offset each other, while winter peak demand increases as EVs are expected to charge when solar is less available during winter months. Annual load increases, as energy consumption from EVs outpaces energy reduction from rooftop solar over the planning period. EVs are expected to add a total of 1,375 GWH, while solar installations are expected to reduce load by 283 GWH and utility sponsored energy efficiency is expected to reduce load by 1,250 GWH. The result is a net reduction of 158 GWH or 0.5% of load in 2041.

Given that utility sponsored energy efficiency (EE) is modeled as a resource option in the optimization process, utility sponsored EE needs to be removed from the load forecast. This is done by removing historical utility EE and then reforecasting load so that it only includes naturally occurring EE.

Energy sales projections are developed for the residential, commercial, industrial, street lighting, and public authority sectors. Retail sale are expected to increase by 5,340 GWH over those for 2020, and a compound annual growth rate of 0.9%.

A. Rooftop Solar

The rooftop solar generation forecast is developed from the capacity forecasts and hourly production profiles for residential, commercial, and industrial customers. The capacity forecast is developed as the product of a customer adoption forecast and an average capacity value. The customer adoption forecast is based on linear regression modeling in Itron's MetrixND and relies on current adoption rates and both current and future payback periods. Payback periods are a function of installation costs, regulatory incentives, and electric bill savings. Historical and projected technology costs are provided by Guidehouse Inc., while projected incentives and bill savings are developed by DEI. The average capacity value, or size of the installed rooftop solar PV system, is derived using historical adoption trends.

Hourly production profiles are developed using 20 years of historical irradiance data from Solar Anywhere and Solcast for five locations across the DEI service territory. The data is modeled in PVsyst to develop capacity factors for all sites and years, which are combined on a weighted average basis to produce 12x24 hourly production profiles. *(DEI IRP, Appendix B, 157 – 158)*

B. Electric Vehicles

The EV forecast is developed from a series of EV forecasts and load profiles. The Electric Power Research Institute (EPRI) provides EV forecasts specific to the DEI service area for three adoption cases (low, medium, and high) and five vehicle types. Vehicle types include plug-in EVs with 10-, 20-, and 40-mile ranges and fully electric vehicles with 100- and 250-mile ranges. Unique hourly load profiles (kWh per vehicle per day) were developed by DEI for each vehicle type, for weekdays and weekends, and for residential and public charging. The EPRI vehicle load forecast and the hourly load profiles are used to prepare jurisdictional hourly level load profiles that are used as an input to the DEI load forecast. *(DEI IRP, Appendix B, pg. 159 – 160)*

C. Alternative Forecasts of Peak Demand and Energy

DEI prepared a high and low load forecast centered on the Base forecast. DEI utilizes a Statistically Adjusted End-use (SAE) model, where the projected efficiencies and saturations of appliance types impact the forecast more than the economics alone. The initial cases with alternate economic scenarios did not provide sufficient variation from the base case to use in the resource modeling. So, the high and low cases were developed using 90/10 Confidence levels established using 1.645 standard deviations of the mean of the forecast to establish an upper and lower band. DEI also added a high case (to meet the current administration's 2030 goal of 50% adoption rate) of EV adoption. *(DEI IRP, Appendix B. pg. 161 -163)*

DIRECTOR'S COMMENTS – LOAD FORECASTING

There is little information on how load is forecasted. Appendix B indicates that Itron's SAE model methodology is used in the residential and commercial sector, but there is no information on what drivers are used in each sector or how the industrial load is projected. The methodology for EVs and rooftop solar is included in Appendix B, but there is not enough information to evaluate the methodology or assumptions. The Director knows some information was provided in a public advisory IRP meeting, but it too was limited.

IV. Demand-Side Resources

A. Summary and Overview

For the DEI's 2021 Integrated Resource Plan (IRP), the utility hired Resource Innovations (formerly Nexant, who also collaborated in the 2018 IRP) to conduct a Market Potential Study (MPS) for Energy Efficiency (EE) and Demand Response (DR) programs over a 25-year time horizon (2021-2045). The MPS provides the energy savings and costs of identified DSM programs.

The first step in the screening process for DSM resources is a technical screening to eliminate from consideration those technologies that are not both technically and commercially available to DEI. The EE and DR programs are primarily selected for implementation based upon their cost-effectiveness; however, as in the 2018 IRP, some programs, such as a low-income program, were chosen for implementation due to desirability from an educational and/or social perspective. The avoided costs used in screening these programs in the MPS to determine the Economic Potential were based on information in the Portfolio Program filing (Cause No. 43955 – DSM 8) approved by the Commission on Dec. 29, 2020.

For this IRP, the EE and DR options are modeled as supply-side resources. Furthermore, DEI affirms that the forecast of loads presented in this IRP incorporates the effects of the historical EE programs impacts in the baseline forecast, subject to anticipated "roll off" into prevailing codes and standards.

B. Energy Efficiency (EE) Resources

DEI is currently implementing its approved 2020-2023 EE portfolio (Cause No. 43955). The EE forecasts used in this 2021 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 2023. The EE MPS included multiple scenarios for projecting future energy savings potential impacts from EE and DR programs for a 25-year forecast period (2021-2045). The identified achievable potential programs in the MPS were designed under the utility cost test (UCT) to pursue cost-effective EE savings.

For this IRP, DEI developed 10 sub-portfolios or bundles of residential and non-residential EE programs as demand-side resource options for selection. This represents 60 EE bundles, less than the number of bundles used in the 2018 IRP. 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 four 2021 MPS scenarios: the Expanded Measure List and the Expanded Measure List with Avoided Cost Sensitivity. These two scenarios were selected due to having the lowest levelized cost per MWh for EE savings.

The EE programs in these scenarios are again divided into five distinct time periods with the same number of periods as they were analyzed in the 2018 IRP. To provide the model with increased granularity of options, the first two sets of bundles were developed with a duration of three years each for the periods 2021- 23 and 2024-26. These three-year periods also correspond with the current and upcoming DSM Plan filings. For the first three-year bundle (2021-2023), the IRP model was required to select the entire bundle that reflects the savings and costs associated with the currently approved DSM portfolio. This first bundle also contained the Income Qualified programs for the 2024-2040 period as these programs are often higher cost than others, thus, they were represented as "must-select" bundle.

For all subsequent bundles (2024-2045), the recommended EE portfolio includes only the bundles selected by the IRP model. In each time period of the IRP, the model had the option to select the bundles based on the "expanded measure" scenario, the "expanded measure list + higher avoided cost" scenario, or no energy efficiency bundle. In all cases, the IRP model selected a bundle covering every time period in all IRP scenarios.

To reduce the computational burden on the IRP models, the next three sets of bundles were developed with a duration of eight years each for the periods 2027-34, 2035- 2042 and 2043-50. Bundles beyond the MPS were defined by extrapolation for the final five years. The annual energy savings and associated cost of each bundle were provided by either the currently approved EE Portfolio (2021-2023) or the MPS (2024-2045). The bundles in the 2040s were used to minimize potential end effects.

The annual megawatt-hours and costs for the bundles were used to calculate a levelized cost in $/MWh for each bundle. These levelized costs were adjusted to cover the costs of program overhead and utility incentives and then credited with the savings associated with avoided Transmission and Distribution costs. These adjustments made the final costs lower than the base levelized costs associated with each bundle. The levelized cost and hourly MWh for each bundle were loaded for selection into the EnCompass model alongside the supply-side resource options. In each of the five time periods, the EnCompass model was allowed to select the bundle based on either of the MPS scenarios or no EE for that time period.

C. Demand Response (DR) Resources

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

DR programs were modeled as selectable bundles and included continuation of existing programs as well as three additional DR bundles that include the additional cost to entice greater participation in DEI's DR program. In addition to the Residential DR programs, DEI also offers Non-Residential Demand Response programs under its Rider 70.

DIRECTOR'S COMMENTS – DEMAND-SIDE RESOURCES

DEI's discussion of EE and DR modeling and associated analysis is limited. EE and DR are discussed in a couple of sections of the body of the IRP report and in Appendix D but is largely repetitive beyond the appendix containing a detailed discussion of current programs. In fact, the above discussion largely reflects the extent of the discussion of EE and DR included in the IRP report, except for the multiple pages devoted to describing existing programs. The Director recognizes EE and DR were discussed in a couple of public IRP advisory meetings, but the level of information was no better than is contained in DEI's IRP.

- Does the anticipated roll-off effect reflect any other adjustment to the load forecast related to the end-life of selected EE measures besides the adjustments related to the prevailing codes and standards *(DEI IRP page 227)*? Where and how would these adjustments be accounted for in the planning process?
- Why is DR kept constant for the reference case and many other scenarios beyond 2025? Is there any reason to assume that there will not be any additional growth going out beyond this year?
- This IRP reports the projected annual gross MWh impacts from the EE programs *(DEI IRP, Table D-1, page 225)*. However, there is no information about the net-to-gross ratios that were used to calculate the gross numbers from the net annual savings or the approach used to project the future number of free riders in the system. This information would be useful to have a better understanding of methodology utilized to estimate the savings from the selected EE programs.
- What are all the parameters considered to group the EE programs into bundles? Was it based on hourly saving load shapes, measure cost, time periods and/or other factors? The IRP mentions that the bundles were modeled based on two MPS scenarios: Expanded Measure List and the Expanded Measure List with Avoided Cost Sensitivity *(DEI IRP page 222)*. However, the IRP does not provide more detailed information about this methodology.

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, Demand-Side Management (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 Midcontinent Independent System Operator (MISO) resource mix. The Company used

Horizon Energy's database within EnCompass to develop scenario specific expansion plans for all of the MISO service territory. 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, carbon, and load assumptions.

B. Method

DEI used scenario planning and sensitivity analysis to address areas of regulatory, economic, environmental, and operating uncertainty. Four distinct scenarios were created for this IRP. They are: 1) Reference case with no CO2 regulation, 2) Reference case with CO2 Regulation, 3) High gas prices, and 4) Low gas prices. Optimized portfolios were developed for the four scenarios through EnCompass. To assess strengths and weaknesses of each optimized portfolio, each optimized portfolio was evaluated under the scenarios for which it was not designed.

DEI noted what it thought were some of the most important insights from the optimized portfolios:

- Carbon regulation or low gas prices are the primary drivers of coal retirements and the likelihood of either is an important factor to consider.
- A price on carbon or low gas prices results in a shift towards CCs, CTs, and solar.
- Gas and solar are consistently selected over wind.
- A coal heavy portfolio would be reliant on the MISO market for a significant part of its energy needs. Conversely, a more diverse portfolio would be more self-reliant across a broader range of conditions.

Insights gained from review of the optimized portfolios were used to design a small number of alternative or hybrid portfolios. The purpose is to capture or build on the positive aspects of the optimized portfolios while minimizing their shortcomings. In this IRP, DEI specified four hybrid portfolios: 1) Balanced Hybrid, 2) Renewables/CC Hybrid, 3) Renewables/CC/CT Hybrid, and 4) Renewables/CT Hybrid. Based on the robustness with which the Renewables/CC/CT portfolio performed across all four scenarios, it was selected as the preferred portfolio. It performed favorably in terms of the level of market purchases, fleet diversity improvement, significant carbon emissions reductions, stability in an uncertain world, all with managing reasonable rate impacts.

After all the portfolios had been analyzed, sensitivity analysis was conducted to examine how portfolio performance was affected by changing a single assumption of interest while holding others constant. This goal was to assess the degree to which portfolio performance or composition would be affected by changing a single assumption that is of particular interest. In this IRP, eight sensitivity analyses were performed, many of which were inspired by stakeholder discussions: 1) High load; 2) Low load; 3) Climate change load; 4) Request for Information (RFI) renewable costs; 5) Higher wind effective load carrying capability; 6) Higher capital costs for gas generation; 7) Upstream greenhouse gases; and 8) Social cost of carbon.

C. Retirement Analysis

Generating unit retirements are selected in the EnCompass model using a five-step process. This is necessary because the fixed cost inputs in the EnCompass model are a main driver for retirement decisions.

1. An initial EnCompass run is done in which the system is modeled over the planning period with no units eligible for retirement.

2. An in-house spreadsheet is used to forecast future maintenance cycles, capital expenditures for maintenance, and fixed operating costs, all based on outputs from the initial EnCompass run. The ongoing capital expenditures and fixed cost forecasts are aggregated together for each unit and are used as an input for a second EnCompass run.
3. The second EnCompass run is done using the aggregated costs from step 2 as an input. All other inputs are identical to the first EnCompass run. EnCompass selects units for retirement when the present value of future fixed and variable costs exceeds the costs associated with retirement and replacement.
4. The third EnCompass run is an hourly production cost simulation where the aggregated ongoing capital expenditures and fixed costs are removed from the model. This simulation uses the expansion plan with retiremetns from step 3 to simulate hourly operation of the portfolio.
5. Like step 2, the outputs from step 4 are used as inputs into the in-house spreadsheet to recalculate the ongoing capital expenditures and fixed costs to account for the declining costs leading to retirement. These costs are then added to the post-process calculations outside of the model.

DEI notes that the cost of replacing a unit is never as simple as a one-for-one replacement of megawatts based on capital costs. Costs may include new capacity from a variety of sources as well as changes to the dispatch of existing units over multiple years.

The retirement analysis considered multiple operating conditions for DEI's Edwardsport Integrated Gasification Combined Cycle (IGCC) plant. This analysis included three operating conditions: operating primarily on coal, conversion to operate exclusively on natural gas, and retirement of the plant. A stakeholder portfolio included adding carbon capture utilization and storage to Edwardsport with the inclusion of associated 45Q tax credits.

The optimized portfolios generally had the Edwardsport IGCC being switched to only natural gas operations early in the planning period. DEI noted the optimization model could not account for several qualitative considerations.

- Edwardsport is DEI's newest and cleanest coal plant, which has a record of improving operations and lowering costs.
- The need for diverse fuel sources and Edwardsport provides resource diversity in the longer term, potential options for carbon capture and storage, and reliability benefits of dispatchable, onsite fuel source.
- Uncertainty about carbon prices, gas prices and availability, new technology availability and timing, and the need for reliability in the MISO region (from an energy and capacity perspective).
- A decision to move to full time natural gas operations at Edwardsport is virtually a permanent decision.
- There are required air permitting changes, loss of specialized workforce for the gasification process, coal contract issues, and operational challenges with restarting on coal.

Based on these qualitative considerations, DEI's preferred portfolio continues operation of Edwardsport on coal through 2035.

D. Scorecard Metrics

DEI correctly notes that the EnCompass 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 judgements about other factors (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 included the following metrics:

- Dispatchable resources as a percentage of load – using 2030 as a representative year, this metric takes dispatchable MWs (coal, gas, and storage) of the portfolio and divides it by the peak load.
- Ability of the portfolio to serve load in all years of the planning period – this metric looks at the amount of unserved energy for each portfolio in all years of every scenario.
- Average percentage of annual market purchases – this metric looks at the amount of market purchases as a percentage of total energy need for each portfolio in all years of every scenario.
- Diversity of resources as measured by Herfindahl-Hirschman Index (HHI) – this metric looks at the diversity of each portfolio in 2030 as measured by the HHI. The HHI sums the squares of the capacity percentage of each resource type and provides a measure of how concentrated or diverse a portfolio is, with a lower HHI showing a portfolio with greater diversity.
- Challenges in executing the portfolio – this metric considers the amount of construction activities that are taking place in the 2020s and includes work related to units going into service in this decade.
- Ability of the portfolio to serve load in extreme weather weeks – DEI used the Portfolio Screening Tool that was developed for stakeholders to vary the composition of the DEI fleet and see how that portfolio would serve load in extreme weeks for winter, spring, and summer. The tool uses actual historic loads, and corresponding historical solar and wind output data.
- Average of portfolio PVRRs across scenarios – this metric takes the simple average of a portfolio's PVRRs across the four scenarios.
- Five-year compound annual growth rate (CAGR) of electric utility rates in the reference scenario without CO2 regulation – this IRP includes a rate impact calculation attributable to only changes in the generation resource plan.
- 2040 CO2 reduction percent – this metric shows the percentage reduction in CO2 tons emitted, including attribution of CO2 to market purchases, relative to the 2005 baseline.
- On track for meeting Duke Energy climate goals – this metric compares the average 2040 CO2 emissions of each portfolio with a linear interpolation between the 2005 baseline and the 2050 Duke Energy Climate Goal of being net zero carbon emissions.
- SO2, NOx, PM emissions and water usage – this metric considers the amounts of SO2, NOX, particulates, and water use for each portfolio.
- Range of PVRRs across scenarios – the range of PVRRs for each portfolio across the scenarios.

DIRECTOR'S COMMENTS – PORTFOLIO DEVELOPMENT & SCENARIO/RISK ANALYSIS

A significant improvement was DEI's decision to use the EnCompass planning model. The model provides considerably more capability than the primary long-term resource planning model used by DEI in previous IRPs. It is especially noteworthy that DEI met with interested stakeholders to get their input on the various model options prior to selecting the EnCompass model. DEI's selection of the EnCompass model was well received by stakeholders and, it is the Director's impression, that stakeholder input was well received by DEI.

Another area of improvement was the fuller analysis of the Edwardsport IGCC. DEI's 2018 IRP was weakened by the failure to review the various operational options presented by Edwardsport. As discussed above, these are continuing to operate primarily on coal, conversion to operate exclusively on natural gas, and retirement of the plant. These possibilities were evaluated by DEI in the current IRP. DEI notes that the optimized runs generally resulted in the Edwardsport IGCC switching to only natural gas operations early in the planning period. Based on qualitative considerations, DEI's preferred portfolio includes the operation of the Edwardsport IGCC on coal through 2035. To DEI's credit they discuss these qualitative considerations and the importance attached to these considerations. Reasonable people can disagree about the weight appropriately given to qualitative factors but being explicit facilitates understanding of what was done.

In sharp contrast with other sections of the IRP, DEI provided a reasonably thorough discussion of the portfolio development and risk and uncertainty analysis processes. It is especially helpful when a utility describes the insights from each step of the process and how these insights helped to inform the next stage of the analysis. The Director notes that this was also an area of the IRP public advisory meetings that was more substantive in the material presented and the level of discussion.

VI. Public Advisory Meetings

To DEI's credit they hosted eight public advisory meetings and two evening sessions. The evening sessions were designed for those customers which could not attend the longer daytime stakeholder meetings. DEI, like other Indiana IOUs in their stakeholder meetings, began each session with a discussion of issues or questions from the previous meeting which required follow up. Also, DEI provided notes following each meeting with the questions asked during and after each session and DEI's written response.

DIRECTOR'S COMMENTS – PUBLIC ADVISORY MEETINGS

While DEI hosted as many or more public advisory meetings as other Indiana utilities and went so far as to have two evening sessions, the content of the sessions was lacking in both substance and tone. The amount and substance of information provided in each slide deck was seriously lacking when compared to the material presented by the other Indiana IOUs in their public advisory sessions in recent years. This is not a new problem for DEI but one that has become larger as other Indiana utilities' IRP processes evolve more rapidly. Also, DEI set a tone that discouraged open discussion. DEI representatives often appeared defensive when responding to questions and argumentative. The tone set here carries over to the IRP itself where there seems to be an unwillingness to be forthcoming about key parts of the analysis. The Director recommends that DEI learn from the actions of other Indiana utilities.

VII. Stakeholder Comments

(Director's responsive comments are indented and in italics)

The following comments are intended to be a representative sampling of the public input into DEI's 2021 Integrated Resource Planning. There were similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Sierra Club

Sierra Club had comments on three broad areas:

1. DEI's stakeholder process.
2. DEI's modeling process and assumptions.
3. DEI's conclusions and proposed plan.

<u>DEI's Stakeholder Process</u>
Sierra Club was appreciative of DEI's efforts to engage stakeholders throughout the IRP process and DEI's willingness to schedule multiple individual calls with stakeholders. However, Sierra Club was concerned that DEI's efforts were "performative."

Sierra Club felt DEI did not provide modeling files and information in a timely fashion. The stakeholder defined scenario development process was also not designed to elicit robust, alternative portfolios. However, DEI's modeling files were not made available to stakeholders until after stakeholder scenarios were due in September 2021. According to Sierra Club, this made it impossible for stakeholders to have time to submit meaningful scenarios to DEI.

<u>DEI's Modeling Process and Assumptions</u>
Specific concerns included:

- DEI used cost assumptions for new gas resources (CTs and CCs) that are lower than other industry sources (specifically NREL's Annual Technology Baseline (ATB) and EIA's AEO report). By under-projecting how low the cost will be for new gas resources, DEI is advantaging these new gas resources over renewables in the resource selection process.
- DEI also used cost assumptions for renewable resources that were higher than other industry sources (NREL's ATB and EIA's AEO) which disadvantaged renewables relative to new gas resources in the modeling.
- The firm capacity credit DEI awards to solar and wind through the effective load carrying capacity (ELCC) metric are lower than MISO's ELCC. DEI has not justified this assumption.
- DEI should have performed an all-source RFP at the beginning of the IRP process rather than using a non-binding request for information (RFI). With an RFI developers have little incentive to provide with competitive bids.

<u>DEI's Conclusions and Proposed Plan</u>
According to Sierra Club, there is little evidence that DEI evaluated the stranded asset risk of continued reliance on gas. While DEI did run a high gas price sensitivity, a high gas generation cost sensitivity, and a high CO2 price sensitivity, DEI did not evaluate the risk posed to its preferred portfolio by continuing reliance on gas. In Sierra Club's opinion, DEI must answer the question: What is the cost and risk posed to ratepayers if DEI moves forward with the preferred portfolio and then a CO2 price is implemented/gas prices go up/gas generation costs are higher than projected?

DEI plans to continue operating Edwardsport on coal until 2034. According to Sierra Club, there is no evidence that DEI robustly evaluated the alternative of retiring the plant or switching to operating on gas full time. All arguments by DEI in favor of maintaining the plant on coal are based on reasons outside of plant economics.

> *Director's Response: The Director disagrees that DEI did not robustly evaluate the alternatives of retiring Edwardsport or switching to operating on gas full time. As noted on pages 15 -17 of the IRP, DEI modeled three alternative operating states: operating on coal, operating on natural gas, and near-term retirement. DEI clearly states that the optimized runs generally resulted in switching Edwardsport to only natural gas operations early in the 20-year planning period. DEI's use of qualitative considerations is clearly stated. One can reasonably disagree with DEI's evaluation of qualitative factors, but judgment is a necessary tool in any complex planning process with so much uncertainty. Good planning makes clear where these qualitative considerations (thus judgment) are unavoidable.*

Reliable Energy

Reliable Energy provided comments on two broad themes:

1. Process and Evidential Issues.
2. Problems with DEI's Preferred Portfolio.

<u>Process and Evidential Issues</u>
According to Reliable Energy, the current informal stakeholder process enables utilities to control the flow of information, impose their own biases on the preferred outcome of the IRP process, and results in the elimination or demotion of otherwise reasonable and economic portfolio alternatives.

One example is the flexibility given each utility to develop the metrics used to determine which of the alternative resource portfolios will be designated the Preferred Portfolio. Reliable Energy believes the Commission should establish minimum required metrics that all utilities must provide. These metrics should include:

- A ratepayer impact analysis by customer class over the first 10 years of a proposed resource's economic life.
- NPV of revenue requirements, including sunk and base rate costs by year with summarized values for 10 and 20 years to get a more accurate sense of customer costs.
- Lifecycle analysis of Carbon Emissions, including upstream emissions.
- Capacity and energy diversification by source and type by year to assess reliability and resilience.
- Percent of energy and capacity forecast to be purchased under PPAs in each year.
- Stranded capital costs due to resource retirements that will later be sought for rate recovery by year under each scenario.
- Costs in base rates associated with each proposed resource retirement.

Examples of other things to be standardized include:

- New investments in all fossil generation should be fully depreciated by 2035 unless equipped with carbon capture.
- Sensitivity analyses should be the primary analytical tool (as opposed to stochastic analyses) to evaluate assumptions regarding commodity prices, capacity and energy prices,

resource capital costs, and load growth. Stochastic modeling is intended to add potential randomness or volatility of key assumptions, but the stochastic results do not inform the Commission about the range of potential impacts. A sensitivity analysis, on the other hand, is used to help determine a model's overall uncertainty, an analysis that is at the core of determining the reliability of a utility's preferred portfolio.

The commission should formalize its involvement in IRP development. Formal involvement would include:

- The IRP and its supporting documentation becoming part of the evidentiary record, making the process (and the generation decisions that eventually stem from it) transparent, and more likely to be fairer to customers.
- The utility, as well as intervening stakeholders, would have the opportunity to provide sworn testimony through witnesses during public hearings to formally support or critique the IRP.
- The Presiding Officers would be available to resolve discovery disputes that cannot be resolved among the parties.
- Parties would receive official notice of new developments in the proceeding, such as deadlines and filed comments from others, rather than relying on periodic checks of the Commission's IRP website for updates.

The outcome of the formal IRP process could include the commission:

- Providing guidance as the IRP development process unfolds, such as requests to the utility for particular actions to avoid errors, balance interests, and encourage reasonable outcomes.
- Balancing requests for changes to the IRP modeling, taking into consideration awareness of market and regulatory constraints, as well as motivations and interests of the parties.
- Providing specific comments on the methodologies, assumptions, programs, etc.
- Defining how customer affordability is measured uniformly and accurately across utility IRPs.
- Addressing issues of reliability and resilience, and protecting the public interest.
- Clarifying questions or seeking additional information regarding the IRP.
- Discussing past IRP analysis, Director Report recommendations, or regulator actions on IRPs in other states where the utility operates; and
- Supporting the parties in working together towards new solutions or alternative approaches to IRP development.

<u>Problems with DEI's Preferred Case</u>
Reliable Energy thinks there are numerous problems with DEI's IRP involving assumptions. Reliable Energy focuses on two they think are most relevant: the assumed capacity price in DEI's analysis and the economics of a CCGT. These are thought to be particularly important given DEI's proposed closure of Gibson 5 in 2025 and Cayuga in 2027 and the replacement of this capacity with a 1200 MW combined cycle facility in 2027.

According to Reliable Energy,

> It is misleading for DEI to state that it "built its preferred portfolio to be flexible so that it can pivot to the most cost effective and reliable technology available at the time." Building a CCGT to replace Cayuga would be a commitment that significantly decreases DEI's

flexibility. The conversion capability is equally a concern for the CCGTs as it is for the CTs. In other words, if the CCGTs cannot be converted to 100% hydrogen and/or green hydrogen cannot be produced economically, the replacement of Cayuga will have significant long-term cost implications as customers not only continue to pay for the stranded costs associated with Cayuga, they will also be asked to pay for the future stranded costs associated of the CCGT replacement by 2050, well ahead of its assumed plant life. *(Reliable Energy DEI IRP comments, pp. 11 – 12)*

In Reliable Energy's opinion, the possible natural gas additions are problematic for other reasons.

- A 1200 MW CCGT will be challenged by environmental groups at state and federal levels. Such challenges could delay a plant beyond its needed in-service date.
- The natural gas prices assumed by DEI may not reflect changes in the market that some analysts believe will persist.
- DEI did not provide sufficient narrative about its gas price forecast other than mentioning it was prepared by HIS and is confidential.
- DEI indicates it used the range in the EIA Annual Energy Outlook (AEO) forecasts to help form the high and low natural gas price cases. However, the AEO forecasts changed materially between 2021 and 2022. The 2022 forecast is significantly higher than the 2021 forecast.

Director's Response: The Director appreciates Reliable Energy's well-intentioned thoughts on how to improve the IRP stakeholder process and, more generally, the development of the IRP methodology and content. Reliable Energy does an excellent job highlighting the difficulty of making utility-specific resource choices in a complex and rapidly changing environment.

Much of Reliable Energy's comments question the effectiveness of the IRP stakeholder process, the usefulness of the Director's review of the IRP and process, and the usefulness of any Commission review in a subsequent regulatory proceeding. The Director appreciates that Reliable Energy is using these comments to address the Commission directly. The Director's response is that the process has seen a massive improvement in the IRP quality and stakeholder input. It is undeniable that there is room for improvement. It is also open to debate how much of these changes would have occurred anyway. Surely the process developed by the Commission has facilitated much of these improvements.

DEI Industrial Group (IG)

The IG is concerned that DEI continues to ignore the excessive costs of operating Edwardsport IGCC on syngas, and DEI's analysis fails to justify this billion-dollar cost to ratepayers through 2034. The Commission should require DEI to demonstrate the cost of its preferred portfolio using a 2023 date for conversion of Edwardsport to natural gas, and not allow DEI to simply rely on the unquantified, qualitative factors cited by DEI. Without including this analysis, DEI's 2021 IRP cannot reasonably be considered a credible planning effort.

The IG states:

1. In the current IRP, DEI modeled four optimized portfolios that all selected Edwardsport to run on natural gas starting in 2023, which was the earliest year DEI believed the operational change would be possible from a regulatory perspective.

2. However, for the hybrid portfolios, including DEI's preferred portfolio, none of the portfolios switched Edwardsport to natural gas before 2035.
3. DEI hardcoded every output of the hybrid portfolios, including the preferred portfolio.
4. In its IRP, Duke states that its preferred portfolio was the result of "lessons learned" from the optimized portfolios and several key sensitivities. (DEI IRP Vol. 1 page 22) Instead, Duke appears to have simply ignored the lessons regarding Edwardsport, given that the optimized portfolios selected the conversion to natural gas in 2023, even for the High Gas scenarios. Deliberate indifference or ignorance to a problem is not consistent with a transparent and honest IRP process.

Based on these concerns, the IG recommended the following:

a. Conduct the IRP analysis in a manner that compares Duke's preferred portfolio to one in which Edwardsport is immediately converted to natural gas operation to determine the PVRRs in both scenarios. In evaluating the option to run Edwardsport as a natural gas unit only, the model should include only the costs necessary to run Edwardsport as a natural gas unit and remove other costs (including removing labor and other O&M costs, post-in-service capital costs, and other costs that are only necessary if the plant is run on syngas).
b. Duke must quantify the values it placed on fuel diversity and other factors it relied on in choosing to hard-key operation of Edwardsport on syngas through 2035. We believe that it is unlikely that any cost justification exists to delay conversion of Edwardsport to natural gas that would outweigh just the O&M savings of approximately $90 million annually over the next 12 years.
c. Absent a credible cost-benefit analysis that demonstrates the factors that Duke considered in delaying the conversion of running Edwardsport on natural gas, Duke's decision to delay conversion is simply a hard-keyed outcome that is not supported by Duke's modeling and should be rejected.

Director's Response: The Director concurs that qualitative factors in any planning exercise should be quantified to the extent reasonably possible. The Director notes, however, that even limited quantification of what had previously been purely qualitative factors involves itself a considerable degree of judgment in the development of any quantitative analysis. Also, any resource commitment involves numerous factors beyond cost as can be seen in even the most basic scorecard. Of course, cost is a critical component to any resource decision, but it is hardly sufficient in a complex planning and operating environment characterized by uncertainty across almost all key drivers or parameters of resource requirements.

Energy Matters Community Coalition (EMCC)

EMCC submitted a report prepared by Synapse Energy Economics, Inc. (Synapse) titled "Deep Decarbonization and Rapid Electrification of the Duke Energy Indiana Service Territory." EMCC commends the Synapse report to the Commission and the Company.

EMCC offers the following highlights for special consideration:

1. The clearest pathway to achieving the IPCC recommendations for the rapid reductions in carbon emissions (in shorthand, "Net Zero" by 2050) required to avoid the direst consequences of climate change necessarily entails "deep decarbonization" of the power

sector in conjunction with “rapid electrification” of the transportation, buildings and industrial sectors of the global economy.

2. The clearest pathway for DEI and its service territory economy to contribute their “fair share” to achieving the IPCC recommendation of “Net Zero” by 2050 globally is to achieve that goal locally for DEI and its service territory economy.
3. To achieve the carbon reduction goals required through electrification in the transportation, buildings, and industrial sectors of the DEI service territory economy by 2050, it is essential for the power sector of that economy (including principally but not exclusively DEI) to decarbonize even more rapidly than the rest of that economy.
4. The most cost effective way for the power sector of the DEI service territory economy to decarbonize as rapidly as required for that entire economy to reach “Net Zero” by 2050 is most likely through rapid deployment of (a) wind and solar generating resources in combination with storage resources (both long and short duration) at utility scale, (b) solar generating resources in combination with storage at distributed scale, and (c) end-use efficiency in all sectors of the DEI service territory economy (including especially but not exclusively the transportation, buildings and industrial sectors).

EMCC thinks DEI should submit a Deep Decarbonization and Rapid Electrification (DDRE) scenario and optimized portfolio in DEI’s next IRP submittal.

> *Director’s Response: The Director concurs that a broad range of scenarios should be evaluated in the integrated resource planning process. A DDRE scenario, or something similar, is a possible future that should be analyzed to better understand potential implications of near-term resource choices.*

Hoosier Environmental Council (HEC)

HEC provides information on the quantity of coal ash DEI currently produces in Indiana, the projected amount over the next 12 years, the disposal costs, and the risks of coal ash damage to natural resources that could be imposed on society. HEC argues continued use of coal for electricity is not in the public’s interest for many reasons, including the production of greenhouse gases, environmental damage from coal mining, and the release of air pollutants. The production of coal ash and the damage it causes is one more reason the use of coal is not in the public interest.

HEC emphasizes the uncertainty associated with coal ash disposal. HEC states:

> Beyond these predictable costs of coal ash disposal and the regulatory requirements, coal ash creates additional cost burdens to society. The regulatory requirements to maintain the disposal structures ends, but the coal ash remains a threat indefinitely. It will be capable of damaging natural resources long after the utility’s regulatory obligation has ended. The cost of spills, releases, and groundwater contamination that happen after Duke’s regulatory obligation ends will fall on society. The cost of using coal includes this lasting potential for damage to natural resources. *(HEC Comments on DEI IRP, page 11)*

As a result, HEC urges the Commission to do all it can to phase out DEI’s use of coal as rapidly as possible.

> *Director’s Response: The Director appreciates the information provided.*

Office of Utility Consumer Counselor (OUCC)

The OUCC raised a few concerns about specific data projections used in the IRP development.

Demand Response Impact on Load
The OUCC noted a difference between the MW load impacts of DR programs shown in Table D-2 on page 226 of DEI's IRP and that projected by DEI in Cause No. 43955 DSM-8. In that Cause, DEI projected 86.75, 91.34, and 96.9 MW of DR for 2021, 2022, and 2023, respectively. The corresponding amounts shown in Table D-2 are 35 MW in 2021, 35 MW in 2022, and 36 MW in 2023. OUCC believes DEI is possibly understating DR in the IRP causing more new resources to be selected than necessary.

Crude Oil Price Forecast
The OUCC is generally concerned that DEI's projections of various commodity prices and their fluctuations are potentially significantly distorted. The OUCC notes that the projection of West Texas Intermediate (WTI) crude used in DEI's baseline forecast, $40 to $60 per barrel through the end of 2022, does not align with actual prices. Crude oil prices are much higher than the projection used by DEI. Also, the price fluctuation is much greater than that used by DEI in the forecast. Similar concerns apply to commodity indices for non-ferrous metals wire and cable, steel, transformers, and regulators.

Environmental
DEI included in the IRP analysis assumptions for compliance with the Coal Combustion Residuals (CCR) Rule, revisions to the Steam Electric Utility Effluent Guidelines (ELGs), and the Clean Water Act 316(b) Rule. DEI provides the compliance assumptions it modeled for each rule, including the technologies and timelines for compliance. But the OUCC states DEI did not provide the numerical cost information associated with the capital and O&M costs assumed for these environmental regulations. The OUCC does not find the assumptions DEI described in Appendix F to be unreasonable, but it is necessary to know the cost details to determine if the cost is reasonable.

> *Director Response: All costs used in the IRP development should be made available to entities that have signed a non-disclosure agreement. The behavior of commodities markets over the last several months and the extent of ongoing uncertainty, especially in fossil fuels, highlights the need to consider a broad range of critical drivers in the resource planning process. Fortunately, integrated resource planning is an ongoing activity that provides opportunities to incorporate new information as circumstances are continuously changing.*

Indiana State Conference of the NAACP (NAACP)

NAACP had several suggestions that it encourages DEI to consider when implementing the IRP going forward.

NAACP notes that DEI opted for a preferred portfolio that relies on a combination of coal, natural gas, and makes minimal progress toward increasing the renewable energy portfolio. NAACP highly recommends that DEI choose a portfolio that takes a more aggressive approach to expanding renewable energy, and one that specifically benefits disadvantaged communities, African Americans, and other communities of color.

Given DEI's continued reliance on coal, NAACP believes DEI should begin to remedy the harms done to disadvantaged communities and African Americans and other communities of color by supporting and providing resources for community-designed solar projects in these communities. NAACP also thinks DEI should give these communities ownership in community solar facilities and give these communities the opportunity to share in the economic benefits.

NAACP suggests that DEI prioritize contracting with African American/minority-owned businesses and setting local hiring and procurement standards to ensure that African American and BIPOC communities are benefitting from these opportunities.

> *Director Response: The Director appreciates the ongoing commitment NAACP has made to the IRP stakeholder process across all five electric IOUs. Some of the suggestions by NAACP are hard to account for directly in the IRP modeling and analyses and others are better addressed in other forums. Nevertheless, integrated resource planning is continually evolving, and utilities have considerable flexibility in the selection of quantitative and qualitative criteria included in IRP scorecards.*

Indiana Advanced Energy Economy (AEE)

<u>Fuel Prices</u>

AEE noted that DEI primarily relied on two fuel price forecasts as bookends in the IRP analysis. That in mid-April, natural gas prices were approximately $4.90 per mmBTU at Henry Hub and futures were above $6.00 per mmBTU. Therefore, AEE recommended that the Commission assume that natural gas prices will be as high as or higher than the high price scenario assumed by DEI in its IRP.

AEE does not fault DEI for not anticipating these higher gas prices. Rather, AEE states this circumstance illustrates that fuel prices are inherently volatile, and that reasonable prudence argues for hedging these risks where possible and affordable.

AEE thinks the primary reason DEI's IRP modeling of the high gas price scenario did not add more renewables sooner than it does is that delayed retirement of coal plants (as imposed as constraints within the modeling) there were not large capacity or energy needs to be met through new resources.

<u>Energy Efficiency</u>

AEE criticizes DEI's sole reliance on an energy efficiency market potential study (MPS). AEE understands and respects using a third-party to develop a potential study and respects the logical construct. AEE, however, observes that the MPS approach delivers highly varying results when performed in different jurisdictions due to differences in policy and regulator expectations. AEE calls for considering a more direct empirical approach to identifying the supply of EE that might be available.

AEE argues that each step of the MPS development involves a plethora of assumptions or parameters that can potentially affect the final estimate of energy efficiency potential. The estimate of "achievable potential" in particular is often empirically weak due to the absence of strong data and theory to project customer response in this "bottom-up" modeling approach.

AEE says there are EE programs across a wide range of savings levels that can be compared in a top-down way. This comparison simply asks: what is the cost per unit of savings in real utility programs that achieve various levels of energy savings? Put another way, AEE thinks that DEI can accomplish energy efficiency at various levels with costs that are like the costs incurred by its peers that perform at those various levels of energy efficiency. Typical energy efficiency potential studies can then use the "bottom-up" approach to identify program designs that achieve these savings levels at costs like those achieved by other utilities.

AEE presented a table showing DEI's 2019 EE programs for commercial customers operated at a level of savings well below that of many peer utilities. Also, the comparison showed that the cost per unit of savings of utilities with much higher savings are not systematically higher than the cost per unit savings for DEI. Similar information was provided for residential programs.

AEE concludes that DEI should be able to achieve a substantially higher level of EE savings without materially increasing the unit cost of savings.

<u>Demand Response</u>
AEE recommends that DEI implement additional DR programs by contracting with one or more DR aggregators and begin implementing rate designs that focus on time-of-use rates and dynamic peak pricing. They also suggest that these efforts target C&I customers in the near term.

<u>Energy Storage</u>
AEE notes that DEI included energy storage among the resources that can be selected in the 2021 IRP. The preferred portfolio includes modest investments in storage in combination with solar beginning in 2027 with cumulative deployment of 1,500 MW by 2038. AEE believes DEI's traditional modeling of energy storage undervalues the resource.

According to AEE, storage thrives on price variability that provides frequent opportunities to buy low and sell high. High peak vs. valley price spreads also increases net revenue. Many IRP models, including the one used by DEI, fail to recognize the full value of storage for at least three reasons:

- They generally under-represent both the frequency and size of hourly price variation
- They ignore intra-hour price variation
- They typically use reserve margins instead of modelling all ancillary service values, which ignores the agility of storage, in that can provide responses to grid conditions without scheduling reserve generation.

AEE presented graphs to illustrate the way in which inter-hour price variation is commonly underrepresented in traditional IRP models, including the one used by DEI. Further, there is significant variation in prices within each hour in actual power markets that is ignored in an IRP model that calculates with only an hourly granularity. AEE also argues that IRP models fall short of describing all the operational limitations of real power plants.

Because of the limitations in how energy storage was modeled in the DEI IRP, AEE considers it a virtual certainty that storage has been under-valued and under-selected in DEI's 2021 IRP in favor of gas peaking capacity. AEE recommends that DEI in the next IRP adopt best practices used in other jurisdictions to better capture the value of storage.

<u>Natural Gas and Market Purchase Risks</u>

AEE has a concern with the scorecard metric measuring the percentage of load purchased from the market. This metric provides an indication of market price risk. AEE observes that most of the time, the marginal generation in MISO is gas-fired. Thus, market price risk is strongly associated with gas price risk. Thus, AEE thinks a better risk metric would be the combined exposure of the portfolio to market purchases and to gas-fired generation. AEE points out that the DEI IRP does not present the percentage of gas-fired generation in the various portfolios.

> *Director's Response: The Director recognizes the limitations of MPS and thinks they are most useful for the analysis and implementation of EE and DR programs in the next five – ten years. The problem is that EE and DR are dependent on how people respond to various price and participation incentives in a complex marketing and decision-making environment. The Director believes the impact of various levels of EE and DR at various cost levels should be evaluated in the IRP model optimization process to provide some insight into how this might affect near-term resource selection. Integrated resource planning involves consideration of resource choices over at least a 20-year period, but today's economics, technology, and policy uncertainties and risks places increased emphasis on understanding potential ramifications of likely resource choices over the next five to ten years.*
>
> *There is little discussion in the IRP about how energy storage was analyzed and how the EnCompass model evaluates the numerous characteristics of battery storage which differentiates storage from other resource options. The Director expects DEI will continually improve its planning process in general and regarding battery storage as a specific example and provide better documentation so that others can better understand how the analysis was done and why.*

Citizens Action Coalition, Earthjustice, and Vote Solar (CAC et al.)

CAC et al. has numerous concerns of varying significance across a range of issues.

<u>Public Advisory Process</u>
CAC et al. noted on the positive side that DEI increased the number of public stakeholder workshops and offered additional workshops in the evening so that more people would be able participate in the IRP process. However, the IRP advisory process was lessened in several ways. There were several crucial topics minimally discussed or not discussed at all in the workshops.

- Data such as growth in customer count and sales were discussed in the Nov. 10, 2020, stakeholder meeting, but the load forecast used in the IRP was not finalized at the time of the meeting. The load forecast was not revisited in any of the remaining six stakeholder meetings.
- DEI never discussed some key modeling inputs such as the use of constraints for new resources and seasonal accreditation of resources.
- DEI provided conflicting information about when and whether stakeholders would receive the modeling files and could review and provide input on DEI's assumptions.
- The level of information presented at each stakeholder meeting was frequently not deep enough to engage more technical stakeholders.
- The tone of the DEI meetings was very different than that of NIPSCO or AES IRP stakeholder meetings, which greatly influenced what could be accomplished in each meeting.

<u>MISO Seasonal Planning Construct</u>

MISO had proposed a new seasonal resource adequacy construct which would implement a differential in seasonal reserve margin requirements rather than remaining static across all seasons. As noted by CAC et al., in the IRP DEI performed modeling that applied a reserve margin of 9.4% across all months of the year. CAC et al. also noted that MISO proposed a new seasonal accreditation capacity (SAC) construct in late 2021. DEI said the SAC lacked enough clarity around the specific impacts to resource requirements. CAC et al. believes it is best practice to explore differing resource adequacy assumptions, including the MISO's proposed construct as closely as possible.

According to CAC et al., DEI should have made a best attempt at modeling both the current RA construct and the anticipated changes to capture the potential impacts of a policy that will have significant impact on DEI's system. CAC et al. is also concerned that by not using MISO's proposed SAC methodology that the IRP model would retain poorly performing thermal units since the contribution of these units to the winter reserve margin is overstated.

<u>Limitations and Flaws in Resource Selection</u>
DEI made several problematic and/or misrepresented modeling assumptions related to new renewable, thermal, and storage resources including:

- Assuming the investment tax credit (ITC) is normalized over the project life instead of receiving a credit in the first year of the project,
- Modeling solar resources with a 0% capacity credit in the non-summer months,
- Reporting a different summer solar capacity credit in the IRP narrative than what was modeled in EnCompass,
- Modeling wind resources with only a summer capacity credit,
- Using an overly optimistic capital cost for new CC units,
- Reporting different first years available for new resources including gas versus what was modeled in EnCompass,
- The output of solar hybrid projects was fixed for the life of the project,
- Using a tighter solar build constraint in certain sensitivities (e.g., high capital cost of CCs), and
- Using an outdated discount rate.

<u>Natural Gas Price Forecast</u>
CAC et al. compared the January 2027 to December 2034 period for the NYMEX futures against the gas prices that DEI modeled. DEI's forecasted prices are on average 17% lower than the NYMEX futures. CAC et al. believes any DEI resource choices put before the commission must be reevaluated considering myriad changed circumstances including natural gas pricing. Recent increases in natural gas prices highlight the possibility of a shifting paradigm of gas price volatility.

<u>Avoided Cost</u>
CAC et al. noted that the Commission's IRP rules require that avoided cost be provided as well as the calculation for each year of the planning period. CAC et al. had to request the avoided cost but even then, no supporting documentation was provided.

CAC et al. thinks the fundamentals of electricity markets have radically changed in the past six months or so, therefore they do not expect the screening of energy efficiency that was completed over a year ago to reflect current avoided costs. Thus, it is important that Duke's upcoming three-year DSM filing and other future IURC applications that depend on similar information are updated with current data since the energy portion of the total avoided cost is typically significant. CAC et al. went on to request DEI to invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings.

Cost of EE Bundles Modeled

CAC et al. found that DEI's EE modeling misreported in the IRP narrative how it modeled the cost adjustments for the EE bundles, which could cause the model to be biased against selecting EE. In reviewing the EnCompass modeling inputs and the underlying workbooks, CAC et al. determined that DEI did not model EE bundle costs adjusted for T&D avoided costs, program overhead, and incentives. Thus, modeling EE bundles as more expensive than they actually are caused DEI to misrepresent the cost of EE bundles in the IRP analysis and biased the model against selecting EE as a resource option.

Scorecard Criteria

CAC et al. has concerns about several of the criteria used for the metrics.

i. Reliability Metric

According to CAC et al., the reliability metric does not actually measure the reliability of a generation portfolio in a manner that is typical to answer such as question. DEI's criteria of "Can the portfolio serve load in all years of the IRP planning?" is evaluated by looking at the average of energy not served for all years across all scenarios as determined by EnCompass. DEI assumes if this metric is below 0.5%, then there is no concern. CAC et al. states,

> "Unserved energy is usually measured in probabilistic simulations that are drawing on thousands of iterations using different combinations of load, weather, and forced outage rate assumptions for thermal units. The modeling Duke performed for this IRP is a single deterministic run that cannot provide enough information to credibly speak to the unserved energy and therefore reliability of a portfolio. EnCompass can be indicative of large gaps in energy served by the utility's own portfolio, but it is not the proper tool to determine whether unserved energy would fall above or below a specific threshold such as 0.5%."
> *(CAC et al. comments, p. 42)*

The reliability metric also considers the average of market purchases in all years across all scenarios modeled. CAC et al. had concerns with this criterion because some of the computer runs allowed for hourly purchases and sales up to roughly the size of DEI's peak load.

Lastly, CAC et al. was concerned with using the 2030 thermal and battery storage resources divided by peak load to evaluate the reliability of portfolios. This metric only evaluates the total capacity of resources in 2030 and not how those resources will perform under system conditions in 2030.

ii. Resilience/Stability Metric

A portion of the Resilience/Stability metric is measured by the application of the Herfindahl-Hirschman Index (HHI) to technology diversity. DEI says HHI sums the squares of the capacity percentage of each resource type and provides a measure of how concentrated or diverse a portfolio is, with a lower HHI showing a portfolio with greater diversity.

CAC et al. says based on the conversations at the stakeholder meetings that the HHI metric was to apply to the capacity of each resource and not to aggregated capacity across each resource type. CAC et al. prefers the resource-specific approach, because having many generators of the same type presents a very different risk for a portfolio dependent on fuel-based generators versus one that is dependent on fuel-less generators. Also, CAC et al. says it is not clear what this risk metric is intended to measure.

A second component of this metric was the performance of the portfolios during extreme weather events using a tool developed by DEI for this purpose. CAC et al. is not opposed to the idea of testing portfolios under different weather events. According to the CAC et al., the PST, however, is not the tool for that purpose, and therefore CAC et al. is concerned about its use in the scorecard for the Resilience/Stability metric. They think the PST is limited in that it does not take into consideration any load growth or savings from new energy efficiency programs. DEI's response was essentially that including energy efficiency would not have a large impact on the result. CAC et al. would like to see DEI back that assertion up with quantitative data.

Another concern of the CAC et al. is how realistically the PST model represents then dispatch of thermal generators.

iii. Environmental Sustainability Metric

CAC et al. think it is challenging to glean meaningful information from the Environmental and Sustainability metric based on how DEI set up the criteria. DEI compares the average 2040 CO2 emissions of each portfolio with a linear interpolation between the 2005 baseline and the 2050 Duke Energy Climate Goal of being net zero carbon emissions. DEI rates the metric as a yes or no. CAC et al. argue the metric needs to be fleshed out to be more than a simple yes or no. For example, does the binary answer capture the benefit of one portfolio being on track to meet the climate goal faster than another portfolio?

Also, the metric for SO2, NOx, PM emissions and water usage was presented as a qualitative metric based on a single year of 2030for each portfolio. CAC et al. state that it is preferrable to see how the portfolio performs over time rather than a single year. DEI should also compare actual numbers or percentage reductions for this kind of metric rather than merely using a qualitative metric.

Director's Response: The Director agrees with CAC et al.'s concern about the substance and tone of the public advisory process. In fact, the Director sees many of the other problems raised by CAC et al in their comments on the DEI IRP as being, in no small part, the result of a failure to adequately communicate by DEI in both the public advisory meetings and the IRP document itself.

A good example of the failure to communicate involves the time allotted to discuss the scorecard performance metrics. Based on the Director's review, the scorecard to be used by DEI in the portfolio evaluation process was not discussed until the sixth public advisory meeting and only 15 minutes was allocated in the meeting agenda. This is problematic for a couple of reasons. First, the IRP stakeholder process should discuss early the objectives of the integrated resource planning exercise. Second, the metrics to measure the performance of the different resource portfolios in meeting these objectives should be discussed early as well.

This is not to say that DEI must have planning objectives and performance metrics that meet the approval of the diverse stakeholders. Rather, DEI needs to have a well-rounded conversation and be open to consideration of other goals and metrics. To be clear, the Director wants to emphasize that the IRP is DEI's document, but DEI should be open to consideration of alternative thoughts and perspectives with the idea of making the resulting IRP better than it might otherwise be.