INTRODUCTION

Duke Energy Indiana, LLC ("Duke Energy Indiana" or the "Company") submitted its 2024 integrated resource plan ("IRP") to the Indiana Utility Regulatory Commission ("Commission" or "IURC") on November 1, 2024. The Company appreciates stakeholders' thoughtful and constructive comments on its 2024 IRP and the continuation of the collaborative process through which the IRP was developed. The Company seeks to continuously improve its planning processes, including engagement with interested stakeholders, and will consider these comments in the development of its next IRP in 2027. In addition, Duke Energy Indiana would like to take this opportunity to provide clarification on particular topics to the Commission and explain areas of respectful disagreement with certain positions put forward in stakeholder comments. The fact that some items are not addressed in these reply comments should not be taken, necessarily, as agreement with stakeholders on those topics.

ANALYTICAL FRAMEWORK, CANDIDATE RESOURCE PORTFOLIOS, AND THE PREFERRED PORTFOLIO

Chapter 2 of the 2024 IRP presents the analytical framework, consisting of generation strategies, planning scenarios or "worldviews," and extensive sensitivity analysis and portfolio variation, in detail. As described in Chapter 2, the generation strategies for the 2024 IRP were developed around actions at the Company's existing coal-fired generating units and the various pathways for compliance with the U.S. Environmental Protection Agency's greenhouse gas ("GHG") rule under Section 111 of the Clean Air Act ("EPA CAA Section 111 Rule").

Energy Matters Community Coalition ("EMCC") comments that "Duke has not incorporated any GHG mitigation in its long-term plan" and that "Duke's preferred portfolio does not appear to make any effort to reduce GHG pollution in response to climate risk or GHG regulatory risk."[1] EMCC suggests that "before procuring any new resources, Duke should evaluate the risk of procuring its preferred resources by 2032 if strong GHG policy is then enacted."[2] However, as explained throughout the 2024 IRP stakeholder process and in the 2024 IRP, improving environmental sustainability, as one of the Five Pillars of Indiana energy policy, was a key planning objective for the 2024 IRP, and GHG regulation, including the strong GHG policy that is the EPA CAA Section 111 Rule, was a major consideration in developing the generation strategies and broader analytical framework for the 2024 IRP. These strategies are illustrated in Figure 1 below.

[1] EMCC comments at p. 11.
[2] EMCC comments at p. 12.

Figure 1: 2024 IRP Generation Strategies and No 111 Strategy Variation

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

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

The candidate resource portfolios that the Company developed based on these strategies are presented in Chapter 4 of the 2024 IRP. Chapter 5 identifies the Preferred Portfolio and provides a detailed discussion of the reasons for the selection of Blend 2.

Both Sierra Club and the Indiana Office of the Utility Consumer Counselor ("OUCC") commented that Blend 1 may have been a more cost-effective, lower risk option, but there are several reasons why Blend 2 is the more reasonable and prudent choice. There are two factors distinguishing Blend 2 from Blend 1.

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.

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,[3] 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.

More generally, both Sierra Club and Reliable Energy point out that delaying the retirement of existing units can allow time for technology to mature and for new resource options to become viable.[4] This is always a consideration in resource planning, but those potential benefits must be weighed against the age, condition, compliance requirements, economic competitiveness, and other risks and challenges associated with the existing unit(s) in question.

Similarly, OUCC suggests that "generally, conversions are more cost-effective than retiring units and replacing their capacity."[5] This may be true in certain cases but may not be broadly generalizable. Duke Energy Indiana specifically tested this presumption with its Convert/Co-fire Coal and Retire Coal generation strategies and found that, in every scenario evaluated, the Retire Coal strategy (which generally replaced coal units with natural gas combined cycle units) had a lower present value of revenue requirements ("PVRR") than Convert/Co-fire Coal. The near-term bill impact, however, is greater for the Retire Coal strategy. This is unsurprising given the capital investment required for new resources, and this result illustrates one of the strengths of the Blend 2 strategy, which balances near-term cost impacts against long-term affordability for customers.

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,[6] 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.

Finally, Clean Grid Alliance ("CGA") comments that "the scale of renewable and energy storage resource additions under the Preferred Plan is insufficient and the timing of most of these additions falls too late in the planning period."[7] However, CGA provides no analysis of costs and benefits to support the position that this would be an improvement over the Preferred Portfolio with respect to

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[3] Sierra Club comments at p. 1.
[4] Sierra Club comments at p. 10; Reliable Energy comments at p. 5.
[5] OUCC comments at p. 3.
[6] Sierra Club erroneously comments (at p. 4) that the amount of new gas investment is lower in Blend 1 than in Blend 2. In fact, Blend 1 arguably has more gas investment because the Cayuga coal units are fully converted to natural gas fuel, whereas in Blend 2, Gibson 1&2 are merely co-fired.
[7] CGA comments at p. 3.

the planning objectives for the 2024 IRP. CGA goes on to suggest that Duke Energy Indiana issue a request for proposals ("RFP") that is "open to wind, solar, and both 4-hour and [long-duration energy storage] hybrids)," reiterating that, in future RFPs, the Company's RFPs should be "open to responses from wind."[8]

The Company's ongoing resource procurement was discussed several times during the stakeholder process for the 2024 IRP as well as in a separate, dedicated RFP stakeholder process. That procurement was open to all resource types, even allowing for wind resources outside of the Company's Midcontinent Independent System Operator, Inc. ("MISO") zone. In IRP Stakeholder Meeting 4, held August 13, 2024, the Company presented an update on the solar, solar paired with storage, wind, standalone storage, and thermal bids it had received in the 2024 procurement (Duke Energy Indiana does not have a "solar-only RFP"[9] planned for release in 2025, as indicated by CGA). The competitive procurement process and recent RFPs are described in Chapter 5 of the 2024 IRP and in more detail in Appendix G: Competitive Procurement Process. The Company invites CGA to actively participate in the stakeholder process for its next IRP.

LOAD FORECAST

The load forecast used in the 2024 IRP is explained in detail in Appendix D to the 2024 IRP. Appendix D also includes detailed discussions of how the Company forecasts certain load modifiers, including major economic development projects, electric vehicles ("EVs"), and behind-the-meter solar, and explanations of how the load forecast is modified to account for these items.

Advanced Energy United ("AEU") expressed concern that electrification trends, specifically increasing heat pump sales, may not be adequately considered in the load forecast.[10] The Company would like to draw attention to pages 347 to 352 of the 2024 IRP, where key load forecast drivers, such as appliance efficiencies and saturation, are discussed. The Company relies on end-use intensities provided by the U.S. Energy Information Administration ("EIA"), which incorporates both short-term and long-term trends. No additional adjustments were made to the EIA inputs.

The OUCC expressed concern that the Company did not consider a sufficiently "high" high load forecast case in its sensitivity analysis, specifically suggesting that additional data center load should have been included beyond the 500 MW of hypothetical data center load that the Company added to its high load forecast case.[11] However, the high load case also reflects an increased proportion of all economic development projects, higher EV adoption, and an optimistic economic forecast.[12]

The OUCC also proposes adding four to nine additional high load sensitivity analysis cases to the 45 resource portfolios presented in the 2024 IRP. Any planning insight that might be gained through this proposed expansion of IRP scope must be considered in the context of the IRP as a whole, which is already a broad and complex undertaking that requires substantial time and resources from the Company and stakeholders. The results of the high load case presented in the 2024 IRP in Chapter

[8] CGA comments at p. 13.
[9] CGA comments at p. 16.
[10] AEU comments at p. 6.
[11] OUCC comments at pp. 7-8.
[12] 2024 IRP at p. 375.

4 indicate that substantial new generation would be required above what is included in the Preferred Portfolio, and it is reasonable to conclude that new resource requirements would scale up with additional load.

Duke Energy Indiana recognizes the potential for new economic development activity to lead to additional major projects, including data centers, to be attracted to its service territory, and will continue to evaluate this potential source of new load as part of its semi-annual load forecasting process while making appropriate adjustments to reflect the uncertainty associated with this new potential demand.[13]

The OUCC also commented that the Company's forecasts for EV and behind-the-meter ("BTM") solar adoption may be overly simplistic, failing to consider region- or state-specific factors in the case of EVs, and assuming a linear relationship between payback period and customer adoption rate in the case of BTM solar.[14] These points are well taken, and the Company will continue to refine its forecasting process as adoption of EVs and BTM solar increase and more data become available. EVs, in particular, remain a nascent technology in Indiana, with insufficient experience to provide the data needed to support a localized analysis with any confidence. Similarly, it is challenging to predict adoption rates for BTM solar at payback periods outside of the range of historical experience. As always, scenario analysis is a useful tool for evaluating alternate potential futures, and the Company explored EV and BTM solar adoption rates above and below base case projections in the 2024 IRP.[15]

In addition to forecasted future load, the 2024 IRP includes historical load data, presented in Appendix D.[16] As the OUCC points out, historical load data provided in Table D-12 in the 2024 IRP differs from the historical data provided in the 2021 IRP.[17] The peak load data do not match because the version in the 2024 IRP does not account for line losses for the wholesale load component. Additionally, the Company identified and fixed a minor error in the 2016 peak value. Regarding energy, the 2021 IRP presented the sum of historical sales by class and company use, whereas the 2024 IRP reflects actual generation. Table 1 below presents the historical system peak data in a format that is comparable to the 2021 IRP.

Table 1: Historical Actual System Peak at the Generator

Year	System Peak (MW)
2013	6,229
2014	5,830
2015	5,863
2016	6,079
2017	5,838

[13] With regard to the OUCC's comments concerning the Meta data center and the load forecast, this load was excluded from the 2024 IRP due to the terms of the special contract with Blocke, LLC. IURC Cause No. 45975.
[14] OUCC comments at pp. 5-6.
[15] 2024 IRP at p. 252, pp. 360-361, and pp. 366-367.
[16] 2024 IRP at p. 371.
[17] OUCC comments at pp. 8-9.

2018	5,904
2019	5,896
2020	5,755
2021	5,976
2022	5,952
2023	5,944

Finally, the Company thanks OUCC for identifying the labeling error in Table D-5 (the label should indicate “GWh” rather than “MWh”) and confirms that correct values were used in the modeling.

DEMAND SIDE RESOURCES AND MARKET POTENTIAL STUDY

Process and Project Scheduling

Resource Innovations (“RI”), in collaboration with Duke Energy Indiana, engaged with the Demand Side Management (“DSM”) Oversight Board (“OSB”) throughout the development of the Market Potential Study (“MPS”), seeking feedback on the schedule, methodology, and draft results. This engagement began with a kickoff meeting that detailed the project milestones and study topics where RI would seek OSB participant input. These topics included the overall study work plan, measure list, market characterization approach and results, technical potential, economic potential, and achievable potential draft results. These milestones and expectations for stakeholder engagement and comments were also included in the study work plan and shared with the OSB participants and their technical consultants for review and feedback. Comments were received from OSB participants, but no objections were raised to the type or frequency of planned stakeholder engagement, nor were requests for additional meetings made; therefore, RI proceeded with the study as described in the study work plan.

Following the milestone and deliverables table included in the study work plan, RI provided ample materials to the OSB participants, which were designed to clearly and transparently relay the study methods and afford the opportunity for stakeholder feedback. MPS study materials were provided to the OSB participants as completed, most often in draft form, specifically to collect OSB participant feedback, including from the Citizens Action Coalition of Indiana (“CAC”). This sometimes meant delivering results later than anticipated as RI was dedicating time to incorporating as much OSB feedback as reasonably possible within the scope, budget, and time constraints of the overall 2024 IRP effort.

RI maintained consistent communication, exchanging project methods, data, and interim files with OSB participants, on average, approximately every nine business days. See Table 2. RI communicated early and often, including noting when project tasks and coordination were taking longer than anticipated in the original project schedule. Further, as part of this collaborative process, RI accommodated multiple requests from CAC for additional review time.

In nearly all cases, the technical representatives of the Joint Commenters (i.e., CAC, Solar United Neighbors, Vote Solar, Environmental Law & Policy Center, and Earthjustice) were the only stakeholders to provide comment. RI repeatedly conveyed the significant influence of study inputs and available data in determining DSM potential estimates. RI requested and responded to feedback on the following: study plan and approach, measure lists, measure savings and costs, detailed measure impact parameters, and references. RI accepted nearly all OSB participant comments, except for those comments that were out of scope for the MPS (several of these have required their own separate study). RI also provided details and data describing the baseline market conditions for the study and incorporated all feasible recommendations from the OSB.

The Joint Commenters, through Energy Futures Group ("EFG"), claim they were only given three opportunities to comment on the MPS due to there being only three OSB stakeholder meetings specifically addressing the topic. However, this assertion is factually incorrect and ignores the multiple opportunities for engagement through both the OSB process and the broader IRP stakeholder meetings. See Table 2 and Table 3.

The Joint Commenters cite three-month gaps between meetings, pointing to OSB meetings on September 21, 2023, and December 15, 2023. However, Duke Energy Indiana had already indicated that MPS updates would be included in all regularly scheduled OSB meetings. In addition to the meetings referenced by the Joint Commenters, RI provided an MPS update at the October 24, 2023, OSB meeting and again at the November 16, 2023, OSB meeting. Following the December 15, 2023, OSB meeting, another MPS update was provided on January 24, 2024, as part of the OSB agenda.

The MPS development process did, in fact, utilize monthly stakeholder meetings to allow numerous opportunities for review and input. In addition to the study work plan identifying that certain materials and OSB comments were to be relayed through email communications, in all communications from RI to the OSB participants, the Company invited outreach by interested parties to follow up directly with RI staff, and RI made a concerted effort to respond to all comments received.

Table 2: Items exchanged by RI and OSB Participants

Study Component	Delivered	Notes	Cadence (days)
Kickoff - RI	9/21/2023	Presentation and Review of Added Scope	0
Correspondence	10/11/2023	CAC Areas of Interest to RI	15
Draft Work Plan	10/23/2023	Comments rec'd from CAC 11/03/23	9
Draft Measure List	10/23/2023	Comments rec'd from CAC 11/03/23	1
Measure List Memo	10/23/2023	Comments rec’d from CAC 11/03/23	1
OSB Meeting	10/24/2023	RI Presentation to OSB	1
Draft 2 Measure List	10/31/2023	Addressed CAC comments	6
Correspondence	10/31/2023	RI response to CAC Areas of Interest memo	1
Final MPS Workplan	11/10/2023	Updates reflecting CAC comments	9
OSB Meeting	11/16/2023	Duke Energy Update to OSB	6

Draft Measure Impacts	11/17/2023	Comments rec'd from CAC	1
Draft 2 Measure Impacts	11/29/2023	Comments rec'd from CAC	9
Draft Market Baseline	12/13/2023	Comments rec'd from CAC	11
COM Impacts to Company	12/22/2023	RI data for DSMore modeling of DSM benefits	8
RES Impacts to Company	1/4/2024	RI data for DSMore modeling of DSM benefits	10
IND Impacts to Company	1/10/2024	RI data for DSMore modeling of DSM benefits	5
OSB Meeting	1/24/2024	RI Update to OSB including status and timeline of deliverables	14
Correspondence	1/29/2024	Response to CAC comments on Measure Impacts, Market Baseline Rev.	5
Stakeholder Meeting	1/30/2024	RI meeting with OUCC regarding SPIDER model (Spacial Penetration and Integration of Distributed Energy Resources)	1
Stakeholder Meeting	2/2/2024	RI meeting with CAC regarding SPIDER model	2
Draft EE Technical Potential	2/16/2024	Comments/request from CAC	14
OSB Meeting	2/21/2024	RI Update to OSB including draft technical potential and status of deliverables	4
Draft Inputs DR Technical Potential	2/21/2024		0
EE Technical Potential Levelized	2/28/2024	RI response to CAC request re: technical potential	6
DR Technical Potential Inputs and Baseline	3/5/2024	Comments rec'd CAC	5
DER Technical Potential and Methods	3/19/2024	Two meetings held for those interested	11
DSMore Measure Avoided Costs Rec'd	3/21/2024	Contains data from Duke Energy Indiana needed to estimate economic potential	3
Initial DRAFT APS to Company	4/12/2024	Draft delivered to Duke Energy Indiana to begin IRP data prep	17
OSB Meeting - Presentation of DRAFT EP, AP	5/15/2024	RI Presentation draft EP, AP	24
Delivered final data to Company	6/18/2024	EE data delivered to Company for IRP modeling (****included changes requested on 05/15/2024 by CAC**)	25
RI Presentation to IRP Stakeholders	6/20/2024	RI Presentation to IRP stakeholders, incl. areas where OSB feedback was received and responses	2
Draft of 2024 MPS Report	7/10/2024		17
Final OSB Presentation	7/16/2024	Provided all final model inputs and outputs, presented on OSB activities and areas where	5

		OSB feedback was incorporated, including DR impacts	
CAC Demand Response Comments Received	7/30/2024	CAC provided comments to Demand Response portions of study	11
CAC Comments Received, Income-qualified	8/8/2024	Email from CAC includes the text, "thank you for incorporating many of our comments from May."	8
Response to CAC Comments on Demand Response	8/29/2024	Responses to comments provided by CAC	16
Final Report	8/30/2024	Final report, inclusive of comments received from CAC and Duke Energy on DR	2

RI acknowledged that study activities required more time than envisioned, but, as the Joint Commenters suggest, allowing additional time to collect and respond to feedback is important for the IRP process. The Joint Commenters express a desire for the study to allow more time for feedback, while also criticizing the process for talking longer than expected.

There were several key study inputs and points of feedback that required additional time to address:

- Stakeholder comments on measure lists, measure algorithms, measure impacts, and study baseline characterization
- Responses to stakeholder areas of interest that were out of scope (as originally described in the work plan reviewed by stakeholders)
- Participating in the public and technical IRP processes
- Incorporating MISO changes to resource adequacy
- Incorporating stakeholder feedback on modeling of updates to Inflation Reduction Act ('IRA") implementation
- Updating models to address stakeholder comments on program costs

RI's attention and focus on addressing these issues contributed to longer-than-expected completion times on project tasks. In fact, RI's responses to stakeholder concerns and Duke Energy Indiana requirements for modeling MISO resource adequacy applied pressure on the broader Duke Energy IRP schedule. Contrary to the Joint Commenters' report, this was primarily related to efforts to incorporate all OSB comments, where appropriate and within the scope of this analysis.

Energy Efficiency ("EE")

The Joint Commenters claim that RI did not respond to feedback on technical potential, yet they contradict this by immediately acknowledging in a footnote that RI did, in fact, respond.[18] The Joint Commenters seem to focus narrowly on written responses, despite that from the outset of the project, RI and the OSB participants agreed that the collaboration could take place in OSB meetings, via email, or by exchange of data. Furthermore, RI staff repeatedly encouraged stakeholders to reach out directly to resolve questions and concerns, which was done in at least two instances

[18] EFG Modeling Report at p. 22; FN at pp. 52-53.

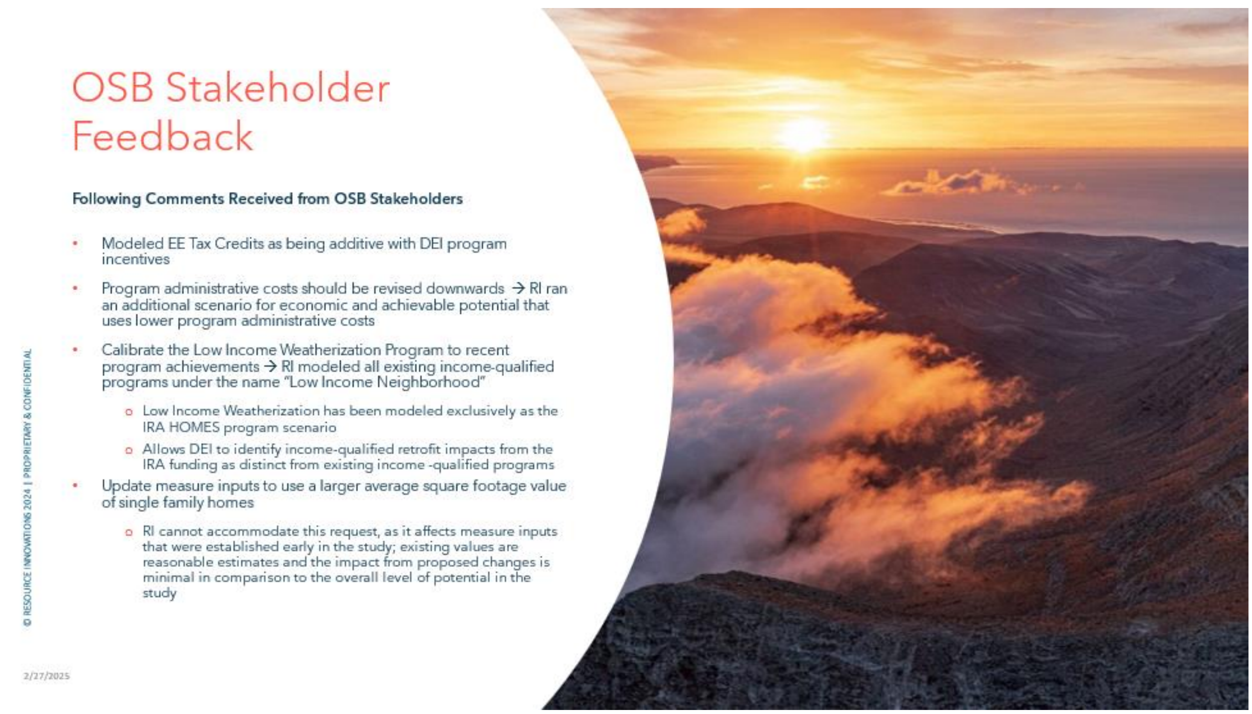
where RI offered ad-hoc presentations and calls to discuss distributed energy resources (DER) and demand response (DR) methods and data.

RI also made several presentations at public and technical sessions Duke Energy hosted for IRP stakeholders that were not anticipated in the original schedule and scope. See Table 3 below.

Table 3: Presentations to IRP Stakeholders

Meeting	Date	Notes
IRP Technical Session 2	4/25/2024	Market Potential Study presentation by RI
IRP Public Meeting 2	04/29/2024	MPS presentation by RI
IRP Public Meeting 3	06/20/2024	MPS presentation by RI
Customer Programs	8/6/2024	Discussion of Duke Energy Indiana Customer Programs by Company

Additionally, as previously noted, part of the delay cited by Joint Commenters resulted directly from efforts to incorporate stakeholder feedback. The following slide is from the IRP stakeholder session on June 3, 2024:



The EFG report recommended that "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." However, the fact that the IQ measures were selected as part of the base case in the 2024 IRP Preferred Portfolio indicates those measures do not unduly burden program level cost-effectiveness.

They were ultimately included in the portfolio regardless of whether they were modeled as a selectable resource or a forced-in resource.

With respect to comments about expanding the EE bundles, there are inherit tradeoffs associated between model processing time and the number of discrete bundles input into the model. Moving forward, the team will consider how to enhance specificity of the bundles while minimizing processing time in the IRP modeling.

Regarding EE levelized cost comments, the EE savings bundles and associated levelized costs were based on savings at the generator using a loss factor of 7.14%. The EE 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.

Demand Response

The Joint Commenters incorrectly assert that feedback on the DR portion of the study was disregarded. In response to email correspondence received from CAC on October 11, 2023, which included feedback on the DR study scope, RI provided a detailed response on October 31, 2023, to all DR comments related to study scope. For example, CAC experts requested the "inclusion of a comprehensive DR measures, including…" and listed 13 specific DR measures. RI responded that 11 out of 13 were included in the study and provided the rationale for why the two remaining suggested measures were excluded (one measure is outside the scope of the MPS, the other measure overlapped with a measure already included in the study). Subsequently, draft DR results were shared with the OSB as the analysis was completed, and feedback regarding DR potential was reviewed, with changes incorporated into subsequent modeling updates. The Company's ultimate response, provided August 30, 2024, included responses to individual comments on the DR study, provided requested supporting data, and very clearly identified where the feedback resulted in study changes. Duke Energy Indiana acknowledges that the study schedule at that point did not allow for multiple rounds of feedback and discussion due to MPS finalization and IRP timing considerations; however, all comments received, and supporting data requested, on the draft results were addressed and when appropriate factored into the study.

MODEL-SELECTABLE RESOURCE OPTIONS AND RESOURCE AVAILABILITY

Several stakeholders commented on the resource options available for model selection for the 2024 IRP, assumptions for certain resource types, and the way certain resources were treated in the modeling.[19] Duke Energy Indiana provided detailed discussions of its analytical methods and assumptions in Chapter 2, Chapter 3, and Appendix C of the 2024 IRP. The Company provided additional detail on supply-side resources in Appendix F, and on demand-side resources and customer programs in Appendix H.

19 EFG, on behalf of Joint Commenters, suggested that Duke Energy Indiana should have considered repowering a wind project; however, the Company does not own that asset. AEU indicated the Company should have included out-of-state renewables as selectable resource options, but generic IRP resources are location agnostic, and in fact the Company's 2024 RFP did allow bids from out-of-state projects.

OUCC commented that, in general, the IRP could have benefited from consideration of a more diverse set of resource options, and suggested that the Company had considered only new combined-cycle resources to replace retiring generation.[20] It is important to recall, however, 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. For example, the fact that simple-cycle combustion turbines ("CT") were not selected in any of the candidate resource portfolios is not an indication that the technology was not considered. CTs were available for model selection, and the capacity expansion model determined that they were not a cost-effective solution to help meet the projected capacity and, particularly important in the 2024 IRP, energy needs of Duke Energy Indiana's customers. Rapidly growing demand for energy and concern about cost risk related to energy market exposure gave the Company confidence in model selection of CCs over CTs, but it did test certain other adjustments to model-developed portfolios, and these variations are discussed in Chapter 5 of the 2024 IRP.

Joint Commenters also commented on resource types considered, recommending that that BTM solar be made selectable in the capacity expansion model. However, adding an additional selectable resource that is very similar to a resource type already represented in the model (utility-scale solar) would complicate the analytics and increase model run times without adding material value. The very small scale of rooftop solar projects combined with the complexity of installing a rooftop system make BTM solar more expensive on a $/kW basis than large, transmission-connected systems. In addition, 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. The predictable and consistent outperformance of utility-scale solar ensures that it will be selected ahead of BTM solar in the capacity expansion model. It would not be reasonable to add complexity to IRP analytics by introducing a resource type into capacity expansion modeling that was known in advance to underperform a resource already available for model selection.

In addition, BTM solar is a customer-owned resource, the deployment of which is outside of the Company's control. It is most appropriately represented as an exogenous variable in the model, which is how Duke Energy Indiana treats it for resource planning purposes. The Company develops a forecast for BTM solar adoption using a payback model and then treats projected energy production from BTM solar as an offset to forecasted load. Joint Commenters contend that the Company should incentivize BTM solar and model it as a selectable resource with the incentive as the resource cost. However, even if the regulatory structures existed for this approach to be viable at scale, it would still be more cost-effective for the Company's customers to use this cost sharing approach for larger systems rather than rooftop projects.

Joint Commenters argue that distributed energy resources lower costs for all customers, citing the Lawrence Berkeley National Lab ("LBNL") report prepared in 2020 for the 21st Century Energy Policy Development Task Force,[21] but that report appears to have evaluated only the potential costs and benefits of distributed resources to the rest of the system, without actually accounting for the costs to deploy the distributed resources. This makes it unsurprising that scenarios with higher solar deployment were found to achieve more savings – if the energy is free, adding more will be better.

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[20] OUCC comments at p. 3.

[21] https://www.in.gov/iurc/files/2020-Report-to-the-21st-Century-Energy-Policy-Development-Task-Force.updated-min.pdf

The LBNL report also did not compare the relative benefits of distributed and utility-scale solar resources, yet it did conclude that the vast majority of savings from distributed solar actually accrue to the generation system, while distribution system costs increase slightly.[22] This suggests that perhaps the value of the solar studied was not contingent upon, and was perhaps even reduced by, the fact that it was distributed. Duke Energy Indiana strongly contends that the approach it took in the 2024 IRP of modeling generic, utility-scale solar as a model-selectable resource and including distributed solar as a forecasted offset to load is correct.

However, this is not to say that a distributed solar project could not be pursued in a particular time and place if circumstances specific to that project dictated that it was reasonable and prudent to do so. It is not the role of the IRP to anticipate and evaluate every possible project scale and configuration, nor is it possible to do so over a 20-year planning period. As explained in Chapter 6 of the 2024 IRP, resource planning employs reasonable, generic planning units and assumptions that are refined and modified as appropriate in the course of plan execution. In other words, the purpose of the IRP process is to answer general questions like, "approximately how much solar should be added to the portfolio and when?" Specifics such as project siting and configuration must necessarily be reserved for plan execution. This is also the reason that the Short-Term Action Plan does not specify what portion of the battery energy storage in the plan should be standalone and what should be paired with solar, as pointed out by CGA.[23] That is by design. As CGA suggests, "standalone storage might be the starting point but not necessarily the goal."[24] The 2024 IRP is also the starting point, and it must be based on generic units and assumptions in order to achieve the desired scope and time horizon for the analysis.

In addition to advocating for modeling additional energy storage configurations and siting strategies, CGA commented that long-duration energy storage ("LDES") should have been included as a selectable resource option in the Reference planning scenario in the 2024 IRP. Duke Energy Indiana and stakeholders discussed the three planning scenarios and the appropriate resource availability assumptions at each of the first three stakeholder meetings in 2024, and Appendix F of the 2024 IRP includes a discussion of emerging energy storage technologies.[25] LDES technologies remain largely pre-commercial and it would not have been reasonable to include them in the Reference scenario. The Company will reassess the technological maturity of LDES in its next IRP.

Moving from model-selectable resource types to annual resource availability, EFG, on behalf of Joint Commenters, indicates an interest in how this constraint may have impacted resource selection prior to 2032. However, as the EFG Modeling Report notes, the constraint was not reached for any resource type other than standalone storage and CCs during that period, so there is no concern that it may have been binding for other resource types other than in dictating the first year of availability. In the case of standalone energy storage, the model did select up to the 300 MW limit in 2028, and it also selected an additional 50 MW of storage paired with solar. It could have selected additional storage paired with solar, but did not. It also could have selected additional standalone storage in 2029, but did not. These results suggest that the resource availability for standalone storage in 2028 was only binding to the extent that the model would have "preferred" standalone storage to storage

[22] LBNL Report at Table 5.11 (pdf p. 195).
[23] CGA comments at p. 8.
[24] CGA comments at p. 11.
[25] 2024 IRP at p. 418.

paired with solar in that particular year. The impact of the resource availability assumption for standalone storage on overall resource selection prior to 2032 is likely to have been immaterial.

NEW SUPPLY-SIDE RESOURCE COSTS AND CHARACTERISTICS

Several stakeholder groups raised concerns about forecasted capital costs and other assumptions for new supply-side resources in the 2024 IRP. As explained in Appendix F of the 2024 IRP, the Company's resource capital cost forecasts are informed by the most up-to-date cost data available from reputable industry sources, including Burns & McDonnell, Guidehouse, EPRI, National Renewable Energy Laboratory's Annual Technology Baseline ("NREL ATB"), the EIA Annual Energy Outlook ("AEO"), Lazard's Levelized Cost of Energy ("LCOE") estimates, and Wood Mackenzie.[26] In addition, Duke Energy Indiana benchmarked its cost forecasts against project cost data from bids submitted to the 2024 Requests for Proposals ("RFP").[27] This approach ensures that the cost assumptions used in the 2024 IRP accurately reflect current market conditions and resources available to Duke Energy Indiana. The Company remains committed to transparent and thorough resource planning and, as part of its continuous improvement efforts, was able to include capital cost assumptions in the public version of its 2024 IRP.

Sierra Club, AEU, and CGA opined that the 2024 IRP capital cost forecasts for renewable energy and battery energy storage resources were too high, citing publications that report lower costs.

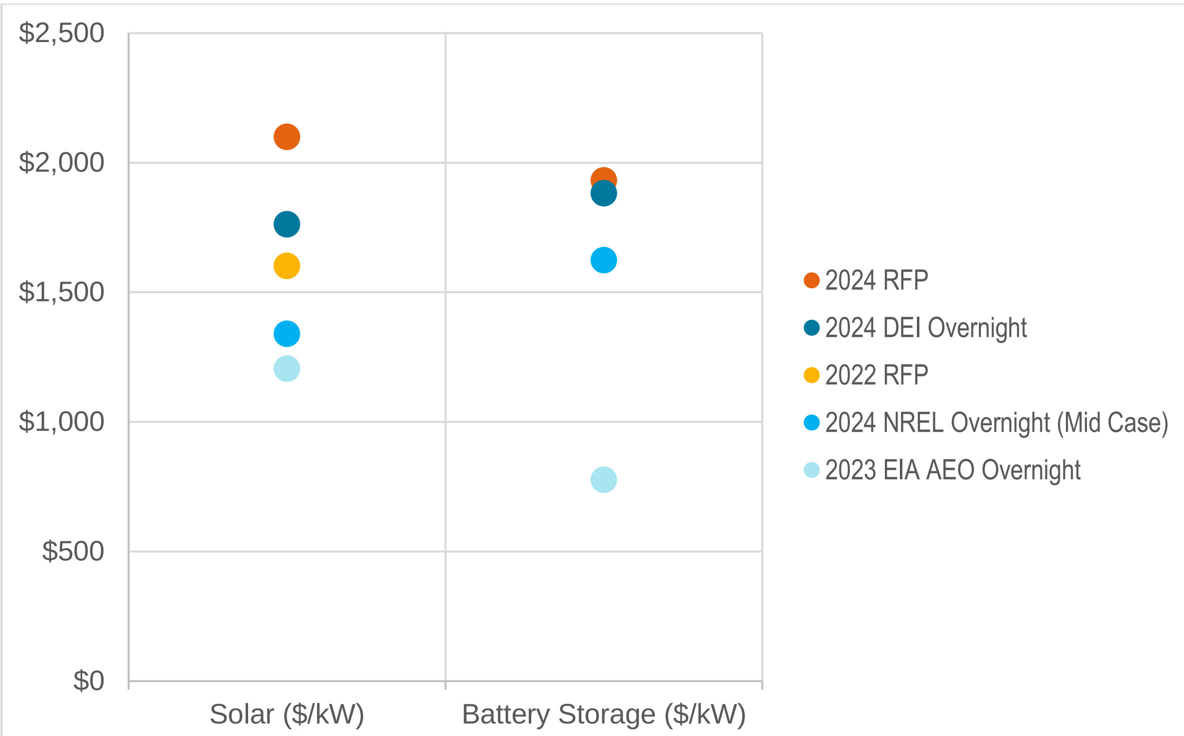
Sierra Club highlighted capital costs from the 2024 NREL ATB,[28] commenting that the capital costs for solar modeled by the Company are "considerably higher" than those projected by NREL. Similarly, AEU referenced EIA, suggesting that "large-scale non-fossil and energy supply resources may be overestimated by several hundred dollars per kilowatt" when compared to EIA's Assumptions to the Annual energy Outlook ("AEO") 2023: Electricity Market Module.[29] However, the 2024 ATB is based on data from the first quarter of 2023, the most recent available historical data at the time the report was prepared. NREL itself noted "Cost fluctuations that may occur between each set of years are not represented, such as the fluctuations because of policy and market conditions that occurred after the first quarter of 2023."[30] The EIA's 2023 AEO is based on even older information. 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. The Company addressed this challenge in the 2024 IRP by benchmarking cost estimates against bid data from the 2024 RFP.

Figure 2, below, presents capital cost projections for solar and battery energy storage projects to be placed in service in 2028. The graph compares the overnight costs used by the Company in the 2024 IRP to overnight costs from NREL's 2024 ATB and EIA's 2023 AEO[31] (shades of blue). The graph also provides average bid prices from the Company's 2022[32] and 2024[33] resource solicitations (shades of orange). While the overnight costs may not be directly comparable to RFP bids, which

[26] 2024 IRP at pp. 418-419.
[27] 2024 IRP at pp. 423-436.
[28] https://atb.nrel.gov/electricity/2024/data
[29] AEU comments at p. 2.
[30] https://atb.nrel.gov/electricity/2024/utility-scale_pv
[31] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2023&cases=ref2023&sourcekey=0
[32] Duke Energy Indiana 2022 CPCN Information Sharing Session 1, October 21, 2022, slide 17.
[33] 2024 IRP Stakeholder Meeting 4, August 13, 2024, slide 23.

may or may not include some amount of expected financing cost, two observations are clear. First, the average bid cost in the 2024 RFP is higher than all overnight cost projections, including the Company's. Second, the cost of solar, for which acquisition costs are available for both the 2022 and 2024 RFPs, has increased considerably in recent years. For these reasons, the Company is confident that the capital cost forecasts it used in the 2024 IRP are the most reasonable.

Figure 2: Solar and Battery Storage Costs ($/kW) – 2028 Projects



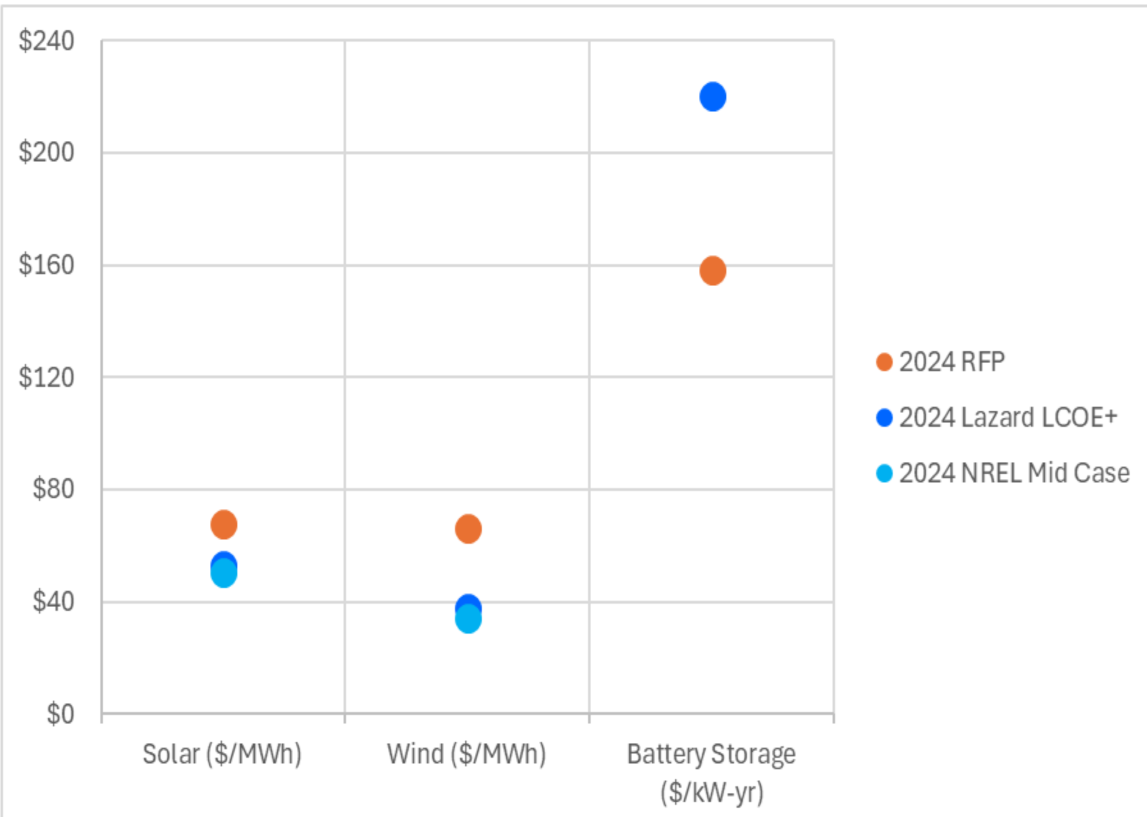
In addition to Sierra Club's and AEU's comments on resource capital cost assumptions, CGA suggested that the Duke Energy Indiana should have used LCOE to compare resource costs, contending that "the overall cost-competitiveness of wind, solar, and storage is not reflected in the 2024 IRP, in which only overnight capital costs by technology type are compared."[34] Fortunately, CGA's concerns are unfounded. The 2024 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 explained in Chapter 2, Chapter 3, and Appendix C of the 2024 IRP document. While LCOE may be "a widely recognized economic measure,"[35] it 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. LCOE is a useful tool for rough comparison of projects *within* a given resource type, but is not appropriate for comparison *across* resource types with different reliability and operating characteristics. CGA suggests that adding "firming" costs to the LCOE resolves this issue, but this is no substitute for full resource planning analytics of the kind supporting the 2024 IRP. It is also worth noting that, although the LCOE estimates referenced by CGA find that renewables

[34] CGA comments at p. 23.
[35] CGA comments at p. 23.

are "competitive with natural gas"[36] even after accounting for firming costs, the resource that provides that firm capacity is assumed to be a natural gas turbine.[37] This underscores the essential role of dispatchable generation in supporting system reliability as market penetration of variable energy and energy-limited resources increases.

Limitations of the LCOE metric notwithstanding, Duke Energy Indiana compared renewable and storage power purchase agreement ("PPA") bids received in its recent RFPs to LCOE projections from the 2024 NREL ATB and Lazard's LCOE publication.[38] Figure 3, below, presents this comparison, clearly illustrating the fact that costs of projects actually available to Duke Energy Indiana exceed estimates from NREL and Lazard, with the exception of energy storage.

Figure 3: Solar and Wind ($/MWh) and Battery Storage ($/kW-year) PPA – 2028 Projects



Note: NREL estimates for Class 7 solar, Class 5 wind. Lazard LCOE estimates for solar and wind are specific to MISO. The Lazard Report does not provide a MISO-specific estimate for energy storage.

EFG, in its modeling report prepared for the Joint Commenters, focuses on CCs and SMRs in its comments on new supply-side resources evaluated in the 2024 IRP. They assert that forecasted capital costs for new CCs in the 2024 IRP are "unreasonably low and inconsistent with the current

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36 CGA comments at p. 22.
37 Lazard Report at p. 15.
38 https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf

market for such facilities."[39] The Company developed cost projections for combined cycle facilities using a combination of actual RFP bids and insights from Duke Energy Indiana's own subject matter experts to ensure that the cost assumptions used in the 2024 IRP reflect real-world market conditions as of the time the forecasts were prepared as accurately as possible.

The Company respectfully disagrees with EFG's contention that CC cost estimates in an IRP recently filed in Kentucky by a utility unaffiliated with Duke Energy Indiana are more appropriate than estimates informed by the Company's own 2024 RFP. However, the Company recognizes that resource costs fluctuate, sometimes rapidly, throughout the process of developing an IRP and after the IRP is submitted. This is why the Company included CC and CT capital costs in sensitivity analysis conducted in the 2024 IRP. The "high CC/CT cost" case tested changes to resource selection, including CC selection, at costs 60% greater than base case assumptions. At the time that IRP assumptions were finalized, the Company considered this the upper end of the plausible range of CC and CT costs and not, as the EFG Modeling Report characterizes it, a "more realistic" estimate.[40] As the EFG Modeling Report points out, even at the high end of the plausible range of prices, the capacity expansion model selects 1,438 MW of new CC capacity by 2032, an amount equivalent to the two 1x1 units at Cayuga. This result, recognized by the EFG Modeling Report,[41] contributes to the Company's high confidence that the investment in new CC capacity Cayuga is reasonable and prudent across a broad range of future conditions.[42]

In addition to CC capital cost estimates, EFG contends in its modeling report prepared for Joint Commenters that the equivalent forced outage rate ("EFOR") assumption for new CCs used in the 2024 IRP is overly optimistic. They provide a comparison to the class average for existing MISO units to support this position and also suggest adding additional performance penalties in cold weather for CC units. However, the Company intends to construct best-in-class advanced CC units and therefore the EFOR assumptions used in the 2024 IRP analytics are appropriate.

EFG also comments on behalf of Joint Commenters that Duke Energy Indiana's cost forecast for new nuclear resources may be optimistic. The Company recognizes that there is tremendous uncertainty regarding the ultimate cost of this developing technology and will continue to evaluate and update its forecasts in future planning cycles. However, the Company reiterates what it stated in its 2024 IRP regarding the potential value of nuclear generation, specifically that, "the possibility of delivering reliable, around-the-clock, carbon-free generation in the future, makes it prudent for Duke Energy Indiana to continue to advance early studies and maintain advanced nuclear as a viable option in future resource plans."[43]

Finally, EMCC and CGA both suggest that additional resource types should have been allowed to benefit from generator replacement assumptions in the 2024 IRP. In its analysis, Duke Energy Indiana assumed that new CC and CT resources installed by 2032 would likely be eligible for generator replacement in the MISO interconnection process and therefore did not burden those

[39] EFG Modeling Report at p. 5.
[40] EFG Modeling Report at p. 5.
[41] EFG Modeling Report at p. 5.
[42] 2024 IRP at p. 162.
[43] 2024 IRP at p. 19.

resources with estimated transmission network upgrade costs until after 2032.[44] EMCC recommends that all resource types be given the same benefit, while CGA recommends that the benefit be extended to only battery energy storage. However, risk of a generator replacement project incurring transmission network upgrade cost increases when the characteristics of the replacement resource differ from those of the resource being replaced. Batteries, for example, must be studied as both load (charging) and generation (discharging). In addition, allocating the interconnection rights of a retiring dispatchable generator to a new non-dispatchable generator would not be in the best interest of customers, when the Company has identified a need for around the clock energy resources.

EXISTING RESOURCES

The Preferred Portfolio in the 2024 IRP calls for Edwardsport to be converted to 100% natural gas fuel by 2030, in compliance with the EPA CAA Section 111 Rule. Both Sierra Club and the EFG Modeling Report prepared for Joint Commenters advocate for earlier conversion to natural gas at Edwardsport. However, as explained in the IRP and supported by the IURC in its order in Cause No. 46038,[45] Duke Energy Indiana's most recent base rate case, Edwardsport is the Company's newest and cleanest coal-fired generation facility, and it has a trajectory of improving operations and lowering costs. The optionality and flexibility provided by the Edwardsport IGCC are critical in this period of transition and market and regulatory uncertainty.

Sierra Club also addressed the Company's other coal-fired generators, suggesting that the heat rate assumptions used in the 2024 IRP analytics were unreasonably optimistic.[46] However, Sierra Club compares annual average heat rates for recent years to projected annual averages based on EnCompass model outputs. Heat rates are not constant, but instead vary with ambient conditions (i.e., seasonally) and, importantly, with the level at which the unit in question is operating. At the risk of over-simplifying, thermal generators tend to operate more efficiently at or near full load, with efficiency declining as unit output decreases. For this reason, heat rates are input into the EnCompass model using polynomial functions of unit loading rather than as constant values. The constants cited by Sierra Club are model outputs (not inputs), reported as average values based on modeled unit operations. Sierra Club correctly notes that capacity factors for the Gibson and Cayuga units have been lower in recent years[47] than EnCompass modeling projects for the future, and it is therefore not surprising to see somewhat lower average heat rates in the model output than in recent history.

STOCHASTIC ANALYSIS OF MARKET EXPOSURE AND SYSTEM RELIABILITY

New to this IRP, Duke Energy Indiana included a stochastic reliability analysis, the "Enhanced Reliability Evaluation", that quantified the ability of resource portfolios to meet customer demands across thousands of 8760-hour weather, load, renewables output, and generator performance scenarios.

[44] 2024 IRP at p. 94.
[45] IURC Order in Cause No. 46038 at pp. 20-23.
[46] Sierra Club comments at p. 14.
[47] Sierra Club comments at p. 13.

EFG, in its report prepared for the Joint Commenters, makes a number of suggestions for modifying this analysis in future IRPs. One primary topic is on the modeling of hourly loads. They discuss that the Strategic Energy Risk Valuation Model ("SERVM") used for the reliability analysis scales the Company's 50/50 peak load and annual energy forecasts to historical weather years. They additionally note that, to the extent that the composition and hourly shape of future load is expected to change due to EV adoption and/or the integration of new large loads, the SERVM load scaling algorithms (which rely on historical load patterns) may not fully capture the weather-dependency and hourly shapes of the new types of load. The EFG Modeling Report recommends that Duke Energy Indiana utilize alternative modeling approaches within SERVM to separately represent EVs and other load categories. The Company agrees that improving the precision of the SERVM 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 the Company's load forecast includes separate hourly profiles, provided sufficient data are available to support more sophisticated analysis.

A core assumption of Duke Energy Indiana's reliability analysis is restricting the modeling to focus on the ability of Company resources to meet load. As discussed in the IRP, the future resource mix and capacity accreditation framework of the broader MISO market is inherently uncertain, and the ultimate purpose of the stochastic reliability modeling is to ensure that Duke Energy Indiana future resource portfolios contribute their fair share to the MISO market and do not place undue burden on the rest of the system. The results of this analysis subsequently compare the reliance of future portfolios on the market to a near-term baseline amount of market reliance.

The EFG Modeling Report recommends directly incorporating interaction with the MISO market into the Enhanced Reliability Evaluation, proposing a probabilistic import availability approach utilized by MISO in its near-term probabilistic analyses, such as its recent 2024/2025 LOLE study. The Company disagrees with this recommendation for two reasons. First, including market interaction misunderstands the purpose of the reliability modeling, which is to gauge the alignment of resource portfolio outputs/availability with Duke Energy Indiana customer load and estimate the degree of market reliance; the purpose is not to identify periods of potential overall market shortfall. Secondly, MISO may feel it is appropriate to utilize recent historical data to estimate import capability for the market as a whole for the next year's LOLE study, but this history may not map accurately onto a future market whose internal transfer capabilities to serve Duke Energy Indiana customers may experience fundamental changes as the underlying resource mix evolves.

In addition to its comments on the enhanced reliability analysis, the EFG Modeling Report recommends additional analysis of "reliance" on economic market energy purchases.[48] This is not, in fact, reliance in the sense of energy adequacy. It is economic market participation to the benefit of customers. However, the Company 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 the Company conducted thorough stochastic analysis of the cost and reliability risk associated with this level of energy market participation. This analysis is described in Chapter 2, Chapter 4, and Appendix C of the 2024 IRP.

[48] EFG Modeling Report at p. 12.

With the new reliability modeling capability having been successfully established and exercised in this IRP, future modeling improvements and assumptions will be reviewed with stakeholders as part of the next IRP engagement process.

SCORECARD METRICS

Duke Energy Indiana included in its 2024 IRP a scorecard summarizing the performance of the six generation strategies in the Reference scenario.[49] The scorecard distills the results of the analytics to a single page, allowing rapid identification and basic assessment of trade-offs across resource portfolios. It is a useful reference tool, but is also a simplification that fails to capture the complexity and nuance of the IRP analysis. Chapter 4 and Appendix C of the 2024 IRP provide additional detail and discussion that is essential for proper understanding and evaluation of the candidate resource portfolios.

EFG, on behalf of Joint Commenters, comments on this limitation with respect to execution risk, suggesting that a project timeline by resource type for each portfolio would be more useful than a single number presented on a scorecard. Of course, execution risk or any other measure must be represented as a single number (or other, similarly simplified indicator) for scorecard purposes, but it could be helpful to provide additional detail elsewhere in a future IRP. The potential benefits, however, must be considered in the context of the generic units used in resource planning, recognizing that certain information necessary to make a useful project plan is not available at the long-term resource planning stage. This could render such an approach impractical.

Both Reliable Energy and Sierra Club commented on affordability metrics, indicating a preference for calculations employing a depreciating rate base methodology. The Company included two affordability metrics on its scorecard – PVRR and customer bill impact expressed as a projected compound annual growth rate ("CAGR"). These metrics serve two 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 the 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.

Sierra Club is correct that depreciating rate base "is more aligned with how the capital costs of [new resources] would be charged to customers,"[50] but is incorrect in the assertion that a depreciating rate base approach is correct for PVRR calculation. As Sierra Club points out, the PVRR of new resource capital costs will be identical under the two approaches *over the course of the life of the asset*. However, as Sierra Club also points out, the asset lives of new resources considered in the 2024 IRP extend beyond the end of the 20-year planning period. This issue of planning period "end effects" (i.e., distortions stemming from inability to adequately account for factors beyond the end of the planning horizon) makes it crucial for new resource capital costs to be levelized for the purposes of resource selection and PVRR calculation. This ensures that costs and benefits are properly

[49] 2024 IRP at p. 130.
[50] Sierra Club comments at p. 7.

aligned in time, and that the costs and benefits for any given resource are reflected in the analysis in comparable proportions.

Using a depreciating rate base approach would front-load revenue requirements associated with new resource capital costs, making new resources less economically attractive early in their lives (higher annual revenue requirement) 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 would introduce bias against new resources with lives extending beyond the planning horizon. That bias would increase as the portion of resource life outside the planning period increased (i.e., for resources added later in the planning period), distorting the affordability evaluation and undermining the validity of the overall IRP analysis.

Sierra Club and Reliable Energy both identify a shortcoming of the PVRR metric, which is that it is an estimate of total, long-term cost that does not capture the timing of rate recovery or the impact to customers in any given year. This is precisely why the Company includes the customer bill CAGR on the scorecard as a secondary affordability metric to supplement PVRR. Balancing total long-term cost and near-term impact to customers was an important consideration in the 2024 IRP.[51]

Contrary to Reliable Energy's stated position,[52] though, 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, for the reasons described above, is subject to significant bias against resources added in or near the year for which the calculation is performed. Furthermore, the IURC reaffirmed in Cause No. 46022 that the PVRR over the full 20-year planning 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.[53]

OTHER ITEMS

The Company thanks Joint Commenters for their comments on grid enhancing technologies but notes that topics such as transmission system topology, power flow controls, and line ratings are well beyond the scope of the IRP analysis. The Company commits to continuing to review grid enhancing technologies and their potential to benefit our system.

CONCLUSION

Duke Energy Indiana appreciates the opportunity to reply to stakeholders' comments on its 2024 IRP. One goal the Company had for this IRP was more transparent stakeholder engagement and opportunities for input. The Company notes that with the possible exception of confusion concerning the energy efficiency MPS development feedback, stakeholders seem to agree that this IRP was an improved process. Duke Energy Indiana strives for continued improvement and will consider these stakeholder comments in the development of future IRPs.

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[51] 2024 IRP at p. 159.

[52] Reliable Energy comments at p. 1.

[53] IURC Order in Cause No. 46022 at p. 40.

There was a great deal of uncertainty in both the regulatory and market environments as the 2024 IRP was developed, and this uncertainty continues into 2025. Lack of clarity is the rule rather than the exception in long-term planning, and while conditions may be unusually volatile at present, the 2024 IRP presents a Preferred Portfolio and Short-Term Action Plan that include resource decisions that are reasonable and prudent across a wide range of potential futures, and that incorporate the flexibility to adapt as conditions evolve.[54] The 2024 IRP, like all IRPs, represents a snapshot in time, incorporating information that is new since the 2021 analysis and laying the groundwork for the next iteration.

[54] 2024 IRP at Chapter 5.