Report on Duke Energy Indiana's 2021 IRP

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On behalf of Citizens Action Coalition, Earthjustice, and Vote Solar

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Overview

The following comments on the 2021 Integrated Resource Plan ("IRP") submitted by Duke Energy Indiana ("Duke" or the "Company") were prepared by Chelsea Hotaling, Anna Sommer, Dan Mellinger, and Stacy Sherwood of Energy Futures Group. These comments were prepared for Citizens Action Coalition of Indiana ("CAC"), Earthjustice, and Vote Solar, pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 Ind. Admin. Code 4-7.

Our review of Duke's 2021 IRP is organized in response to guidance on IRP preparation in the IURC's IRP Rule.

We look forward to continuing to work with Duke to address the issues identified here to improve Duke's next IRP and request Duke to invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings.

Overall, we have significant concerns about this IRP. Our concerns broadly relate to Duke's stakeholder engagement process throughout this IRP; the unreasonable nature of key modeling inputs and methods that bias its model in favor of natural gas units; its evaluation of portfolios that relied on metrics that lack analytical robustness; and the lack of clarity and detail in its short-term action plan. These concerns combined with the wholesale change in electric market fundamentals that have taken place in the past six months or so collectively give us pause on relying on the results of this IRP for resource decisions. We ask Duke to work with stakeholders to adjust its analysis to correct for these important deficiencies in its IRP, in particular that it invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings.

Table 1 gives the Indiana IRP rule sections and provides the section in which those requirements will be addressed in detail. Our review of Duke's 2021 IRP and our participation in its stakeholder workshops raised the following main categories of concern:

- The stakeholder process did not facilitate a two-way exchange of information and ideas and left stakeholders blind to critical pieces of information until after the IRP was filed (Section 2);
- Duke did not use best efforts to account for the potential impacts of Midcontinent Independent System Operator's ("MISO") switch to a seasonal capacity construct and MISO's changes to accreditation of thermal resources (Section 3.1);
- Duke did not consider the winter seasonal accreditation benefit for wind resources in its base case assumptions (Section 3.2.2);
- Duke was not transparent about the capital costs it modeled, which diverged significantly from those it presented during the stakeholder workshops (Sections 3.3 and 3.4);
- Duke assumed normalization of the Investment Tax Credit ("ITC") instead of a capital cost reduction in the first year of a project which can lead to higher capital costs of solar projects (Section 3.2.1);

- Duke's modeled cost of new combined cycle ("CC") units are significantly lower than the costs for comparable sized projects in neighboring states (Section 3.3);
- Duke's Demand Side Management Market Potential Study constrained important potential contributions to the energy efficiency opportunities available to the Company, although we found that the IRP bundles appropriately aligned with the savings identified by the MPS (Section 5.1);
- Duke did not model the adjusted energy efficiency bundle costs that include reductions for avoided transmission and distribution ("T&D") benefits (Section 5.1.2); and
- Duke's scorecard relied on a variety of flawed and/or non-specific measures of reliability, resilience, and environmental sustainability (Section 7.2).

Table 1. Summary of Duke's Achievement of Indiana IRP Rule Requirements

IRP Rule Section	Description	Findings	Citation
Integrated Resource Plan Submission	The IRP submission should include a non-technical appendix and an IRP summary that communicates core IRP concepts and results to a nontechnical audience.	**Partial**	See Section 1
Public Advisory Process	The IRP process should be developed and carried out to include stakeholder participation.	**Partial**	See Section 2
Integrated Resource Plan Contents	The IRP should provide stakeholders with all of the information necessary to understand how the IRP modeling was performed.	**Partial**	See Section 3
Energy and Demand Forecasts	The IRP should clearly explain how energy and demand forecasts were developed and used for the IRP.	**Mostly**	See Section 4
Description of Available Resources	The IRP must include important characteristics for existing and new resources included in the IRP.	**Partial**	See Section 5
Selection of Resources	The IRP should describe the screening process used for evaluating future resources.	**Mostly**	See Section 6
Resource Portfolios	The IRP should discuss the preferred portfolio and discuss how alternative portfolios were developed to consider different scenarios.	**Partial**	See Section 7
Short Term Action Plan	The IRP should discuss how the preferred portfolio will be implemented over the next five years.	**Not Met**	See Section 8

1 Integrated Resource Plan Submission

Section 1 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-2 of the Indiana IRP Rule. Please see Table 2 below for our findings.

Table 2. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-2

IRP Rule	IRP Rule Description	Finding
4-7-2 (c)	Utility must submit electronically to the director or through an electronic filing system if requested by the director or through an electronic filing system if requested by the director, the following documents: (1) The IRP	**Met**
4-7-2 (c)	(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts; (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models (in electronic format); (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file	**Partial**
4-7-2 (c)	(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director and (B) A simplified discussion of the utility's resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	**Mostly**

For its 2018 IRP, Duke used the System Optimizer ("SO") capacity expansion model and the Planning and Risk ("PaR") production cost model. In our comments on the 2018 IRP, we suggested that Duke conduct a Request for Information ("RFI") in order to evaluate different models to replace SO and PaR. It was our understanding that Duke was in the process of choosing a new model since the vendor of SO and PaR had ceased supporting those platforms. Although Duke did not employ this process to select a new model, Duke did internally evaluate several capacity expansion and production cost models and ultimately decided to move forward with the EnCompass model. We commend Duke for moving to EnCompass, as this model can perform capacity expansion and production cost modeling, can simulate paired resources such as solar/battery hybrids, and offers better transparency into the modeling inputs and outputs.

While Duke's use of the EnCompass model for capacity expansion and production cost modeling is a significant improvement for this IRP**, Duke did not provide to stakeholders certain important information, including modeling output files and some of the required information to meet the technical appendix requirements**. For this IRP, Duke did provide stakeholders with the EnCompass modeling inputs files, however, modeling output files, with information such as the capacity expansion plan, resource generation, emission, and revenue requirements, were not provided. We had to submit an informal discovery question to Duke in order to receive the revenue requirement workbooks.

One of the frustrating aspects of Duke's stakeholder process for this IRP was the schedule for provision of modeling files and related information to interested stakeholders. Duke initially committed to providing modeling files to stakeholders in April 2021, however it did not transmit files relevant to its own system until September 2021. After an initial review, we made some recommendations to Duke for changes to its database, which it indicated it would make. However, updated files were not delivered until November 2021, at which time it was too late to allow us to provide any additional feedback because the IRP was nearly final. We would recommend that Duke consider a process of releasing and sharing information similar to the process used in AES IN's most recent IRP, submitted in December 2019. AES IN used a file sharing site to share data at several points throughout the IRP process, and had a schedule of release dates for when they would provide stakeholders (who had executed nondisclosure agreements) with key information like capital costs, resource constraints, key modeling inputs, and modeling results. We believe that this data sharing approach helped to facilitate stakeholder involvement, expectations, and input throughout the process and ultimately increased stakeholder engagement. AES IN's approach is much closer to satisfying 170 IAC 4-7-2(c) which requires each utility to provide input and output files in electronic format, as well as include "documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP."

It is not just the sharing of information in a timely fashion that is important. It is also important for Duke to be clear about when it needs feedback so that it can incorporate that feedback. So the schedule should include a due date for feedback as well.

2 Public Advisory Process

Section 2 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-2.6 of the Indiana IRP Rule. Please see Table 3 below for our findings.

Table 3. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-2.6

IRP Rule	IRP Rule Description	Finding
4-7-2.6 (b)	The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	**Partial**
4-7-2.6 (c)	The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by: (1) the interested parties; (2) the OUCC; (3) the commission staff.	**Partial**
4-7-2.6 (e)	The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following: (A) An introduction to the IRP and public advisory process, (B) The utility's load forecast, (C) Evaluation of existing resources, (D) Evaluation of supply-side and demand-side resource alternatives, (E) Modeling methods, (F) Modeling inputs, (G) Treatment of risk and uncertainty, (H) Discussion seeking input on its candidate resource portfolios, (I) The utility's scenarios and sensitivities, (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	**Partial**
4-7-2.6 (e)	(2) The utility may hold additional meetings.	**Met**
4-7-2.6 (e)	(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	**Met**
4-7-2.6 (e)	(4) The utility or its designee shall: (A) chair the participation process; (B) schedule meetings; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and (D) develop and publish to its website meeting minutes within fifteen (15) calendar days following the meeting	**Partial**
4-7-2.6 (e)	(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	**Met**
4-7-2.6 (e)	(6) The utility shall take reasonable steps to notify: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC	**Met**

2.1 Stakeholder Process

In the comments filed on the 2018 IRP, CAC expressed concern about Duke's response to stakeholder feedback and recommendations. There were several instances where we provided suggestions for improvements to Duke's modeling approach or its inputs, and Duke either disagreed with the suggestion or said that the suggestions would be taken into consideration for the next IRP. Some of CAC's requests included modeling on a UCAP rather than an ICAP basis, removing the application of a monthly reserve margin constraint, lowering the capital costs of solar and wind resources, removing limitations on the retirement of the coal plants, and not applying a transfer limit or other constraint to limit market purchases.

For its 2021 IRP, Duke did switch from modeling on an ICAP to a UCAP basis and did model some optimized retirement dates for all coal units except for Edwardsport. However, many of our prior comments, as well as feedback raising new concerns in the 2021 process, have again gone unaddressed or have been pushed off to the next IRP.

In the last IRP, we also expressed concern about Duke applying the reserve margin to all months of the year, using low capital costs for CC gas units, high capital costs for renewables and storage, and Duke's lack of openness to receiving and incorporating feedback from stakeholders. We raised our concerns during the public stakeholder workshops, submitted written comments following the workshops, and conducted technical calls with Duke.

For its 2021 IRP, while Duke was somewhat receptive to **one** of our concerns (that it was not modeling seasonal accreditation of wind resources), this was the only change made, and it was only made into a sensitivity with Duke refusing to include the change in the base modeling assumptions.

In addition, for this 2021 IRP, while Duke increased the number of public stakeholder workshops and offered additional workshops in the evening so that more people would be able to participate in the current IRP, there were several crucial topics that were minimally discussed or not discussed at all in these workshops:

- Duke spent significant time during the first stakeholder workshop discussing certain data such as growth in customer count and sales, but at the time of the meeting – November 10, 2020 – the load forecast that would be used in the IRP was not even finalized.[1] Yet Duke never revisited the load forecasting topic in any of the remaining six stakeholder meetings, except to mention that a climate change load forecast scenario would be modeled.
- Duke never discussed some key modeling inputs such as the application of resource constraints for new resources and seasonal accreditation of resources.
- Duke's stakeholder IRP workshops provided conflicting information about when and whether stakeholders would receive the modeling files and have the ability to review and provide input on Duke's assumptions.

[1] Duke Response to CAC Informal Discovery 1.3.

- The level of information presented at the stakeholder workshops was frequently not deep enough to engage more technical stakeholders. For example, during the 4th stakeholder workshop, the following graph of Duke's gas price forecasts was presented with the y-axis redacted, conveying no meaningful information except that prices will increase, but it was impossible to tell at what rate or how those prices compare to other gas price forecasts:

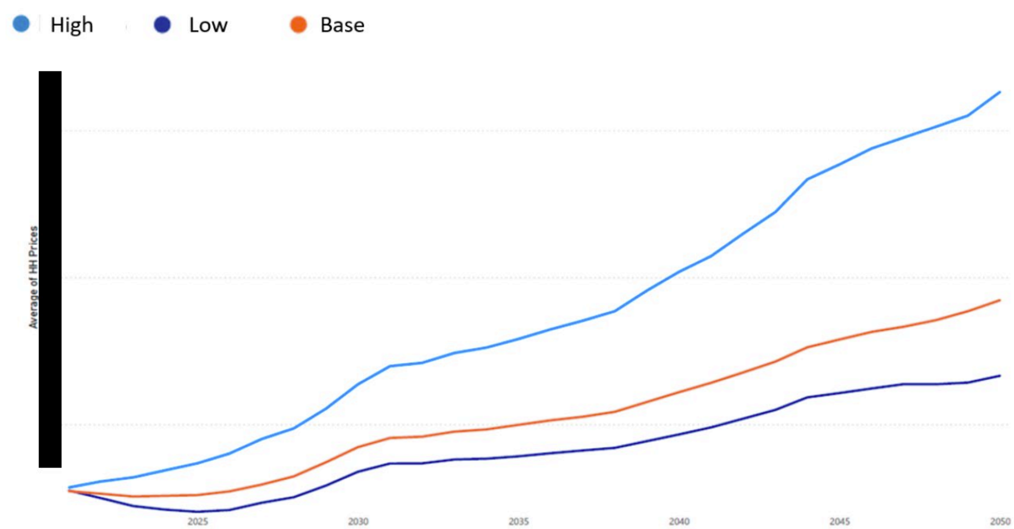

Figure 1. Gas Price Forecasts Presented During 4th Stakeholder Workshop[2]

In the last IRP, we also asked Duke to set a rough schedule of meetings so that stakeholders would know when they were likely to need to engage and when they would receive information. Duke gave a rough schedule for the stakeholder process at its first meeting. The schedule was as shown in Figure 2.

[2] Duke Energy Indiana's IRP Presentation at 4th Stakeholder Workshop (June 21, 2021), slide 13.

Meeting #/Date*	Topics
1) November 10	Introduction; Lessons learned/improvement opportunities; Load forecasting
2) Late January	Scenarios, AMI data & customer programs, DERs
3) March/April	Optimized portfolios & misc. topics
4) June/July	Modeling results; hybrid and stakeholder portfolios
5) August/September	Modeling results and sensitivities
6) October	Preferred portfolio

Figure 2. Schedule of Meetings Given at November 10, 2020 Stakeholder Workshop

Notably, optimized portfolios were planned for presentation at the March/April meeting and hybrid and stakeholder portfolios for the June/July meeting. The anticipated filing date was still November 1, 2021.

By the June 12, 2021 meeting, the timeframe for the presentation of the optimized, hybrid, and stakeholder portfolios had been extended out to August 2021. The anticipated filing date was still November 1, 2021, and no modeling files or other confidential information had been shared.

The presentation of the optimized, hybrid, and stakeholder portfolios did not occur until the September 10, 2021, meeting, though. The anticipated filing date was still November 1, 2021, and no modeling files specific to Duke nor any other confidential information had been shared.

The issue is not the delay in these discussions, but the lack of transparency about whether the delay would affect stakeholders and particularly how Duke would modify the process so the delay did not shortchange the participation of stakeholders. Because the schedule was not being modified simultaneously to allow extra time for feedback, the process became more of a one-way street with Duke providing information but declining to accommodate feedback.

Finally, despite hiring a facilitator, the tone of Duke's meetings was very different than that of NIPSCO or AES IN's workshops, which greatly influenced what could be accomplished in each workshop. We would encourage Duke to sit in on an AES IN, DTE Electric, and/or Dominion Energy South Carolina ("DESC") stakeholder workshop to learn firsthand why those workshops strike such a different tone. There are several overarching recommendations that we have in this regard:

1. Try to avoid debate – There were numerous times that discussion devolved into debate about the merits of a party's position. Instead, all parties should be encouraged to ask questions to better understand a particular position.[3] EFG and our clients are committed to doing our part to help change the tone for future stakeholder workshops.
2. Ask for written comment – DESC employs a practice for taking stakeholder comment that works well. It asks for input on specific questions related to the material presented during the workshop and gives a two-week deadline for receipt of comments on that material. Comments unrelated to the questions, but germane to the process or the IRP are also welcome. At the subsequent workshop, DESC goes through the feedback and explains how it will incorporate the feedback or why it chose not to.
3. Present information that is tractable and meaningful – As Duke prepares its stakeholder workshop, the team can ask itself questions like, "Is the depth and breadth of the information presented sufficient to convey the issue?" and, "If I were learning about this methodology/information, is there enough substance to provide my thoughts on the matter?"
4. Allow for opportunities to address confidential information – If information cannot be conveyed in the workshop because of confidentially restrictions, then provide it to stakeholders who have signed an NDA and make clear when feedback is needed in order for it to be incorporated.

These workshops can certainly help to reduce disagreements that will manifest before the Commission, but the stakeholder workshops must be structured in such a way that all parties feel that their position has been heard and that a discussion of those positions was had.

Given the issues with this stakeholder process, we request Duke to invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings. We ask that a process for this work be agreed upon beforehand.

[3] For some suggestions about how to approach disagreement in discussions, please see: https://www.inc.com/lolly-daskal/7-simple-ways-to-deal-with-a-disagreement-effectively.html

2.2 Discovery Responses

In several instances, CAC submitted informal discovery questions that were then objected to by Duke and to which Duke did not respond or did not fully respond. In one example, CAC submitted a question[4] to receive the underlying workpapers, with formulas and links intact, used to develop the fixed operations and maintenance ("FOM") and capitalized maintenance cost streams for Duke's existing thermal units. O&M and capitalized maintenance modeling inputs are information that stakeholders would normally have access to, as this information is a key part of the modeling inputs. Obtaining this information was important for two reasons:

(1) Duke modeled different cost streams for different scenarios, i.e., there was one FOM cost stream for the units being modeled with a carbon price, another cost stream for the Biden 90 scenario, and another cost stream for any run with no carbon price. Being able to see these calculations would help stakeholders better understand why and how the FOM and capitalized maintenance is changing between the different modeling runs.
(2) Stakeholders cannot conduct their own modeling and develop their own portfolios that examine alternative thermal retirement dates within EnCompass, without clarity on how the FOM and capitalized maintenance calculations were developed in the first place.

In response to CAC's discovery question, Duke objected to providing the FOM and capitalized maintenance workpapers:[5]

> *Duke Energy Indiana objects to this request as vague and ambiguous, particularly the portion of the request seeking "the version of these workbooks that show the calculation . . ." Duke Energy Indiana has previously provided the actual inputs to the 2021 IRP modeling and objects to providing information not used in the 2021 IRP as overly broad and not reasonably calculated to lead to admissible evidence in this proceeding.*

It is confusing that Duke "objects to providing information not used in the 2021 IRP", when the IRP narrative says: [6]

> *1. An initial EnCompass run is conducted in which the system is modeled over the planning period with no units eligible for retirement. The key output of this run is the capacity factors, heat inputs, variable costs, service hours and CO_2 emissions of each unit in each year of the planning period.*
>
> *2. An in-house spreadsheet is used to forecast future maintenance cycles, capital expenditures for maintenance, and fixed operating costs, all based the outputs from the initial EnCompass run. The ongoing CAPEX and fixed cost forecasts are aggregated together for each unit and are used as an input for a second EnCompass run.*

[4] Duke's Response to CAC Informal Discovery 3.1a.

[5] Duke's Response to CAC Informal Discovery 7.1a.

[6] Duke Energy Indiana 2021 IRP, pages 42-43.

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

Clearly the information we requested is being used in the IRP and was developed for this purpose, and there are documents that would show the calculations and assumptions that Duke made. Our concern is that Duke is shielding this important information from review because it directly influenced the retirement dates that were included in each portfolio.

3 Integrated Resource Plan Contents

Section 3 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-4 of the Indiana IRP Rule. Please see Table 4 below for our findings.

Table 4. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-4

IRP Rule	IRP Rule Description	Finding
4-7-4 (1)	At least a twenty (20) year future period for predicted or forecasted analyses.	**Met**
4-7-4 (2)	An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	**Met**
4-7-4 (3)	At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	**Partial**
4-7-4 (4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	**Mostly**
4-7-4 (5)	A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	**Partial**
4-7-4 (6)	A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	**Mostly**
4-7-4 (7)	The resource screening analysis and resource summary table required by section 7 of this rule.	**Mostly**
4-7-4 (8)	A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	**Partial**
4-7-4 (9)	A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	**Partial**
4-7-4 (10)	A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	**Partial**
4-7-4 (11)	A discussion of the: (A) inputs; (B) methods; and (C) definitions.	**Partial**
4-7-4 (12)	Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	**Mostly**
4-7-4 (13)	A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use.	**Not Met**
4-7-4 (14)	The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility; (B) Load research developed in conjunction with another utility; (C) Load research developed by another utility and modified to meet the characteristics of that utility; (D) Engineering estimates; and (E) Load data developed by a non-utility source.	**Not Met**
4-7-4 (15)	A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	**Met**
4-7-4 (16)	A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	**Met**
4-7-4 (17)	A discussion of the designated contemporary issues designated, if required by section 2.7(e).	**No Response**

4-7-4 (18)	A discussion of distributed generation within the service territory and the potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and (D) load forecasting.	**Mostly**
4-7-4 (19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	**Met**
4-7-4 (20)	A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development	**Met**
4-7-4 (21)	A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	**Met**
4-7-4 (22)	A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	**Met**
4-7-4 (23)	A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	**Met**
4-7-4 (24)	A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	**Partial**
4-7-4 (25)	A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources. (C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	**Partial**
4-7-4 (26)	A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	**Partial**
4-7-4 (27)	A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies, and sensitivity analysis; (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC); and (C) Reliability criteria for transmission planning as well as the assessment practice used.	**Partial**
4-7-4 (28)	A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use and (B)The utility's effort to develop and improve the methodology and inputs.	**Partial**

4-7-4 (29)	An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement; (B) The avoided transmission capacity cost; (C) The avoided distribution capacity cost; and (D) The avoided operating cost.	
4-7-4 (30)	A summary of the utility's most recent public advisory process, including: (A) Key issues discussed and (B) How the utility responded to the issues.	**Partial**
4-7-4 (31)	A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	**Met**

3.1 MISO Seasonal Planning Construct

MISO has been working on the redesign of its resource adequacy ("RA") construct for several years now. In November 2021, it filed at the Federal Energy Regulatory Commission ("FERC") in Docket No. ER22-495 for seasonal-based changes to both the RA construct and its capacity accreditation methodology for thermal generators. On March 9, 2022, FERC issued a deficiency letter to MISO and asked a detailed set of questions about key aspects of the proposed changes such as the use of data from different seasons to accredit resources, why MISO's thermal accreditation methodology would do a better job of determining unit performance than its current approach, and why MISO is proposing a different accreditation method for different technology types. On April 8, 2022, MISO responded to FERC's letter, and on April 29, 2022, intervening parties provided their responses to MISO's response. It is unclear when FERC will rule on the petition and the implementation of the construct is pending FERC's approval.

While presentations at MISO Resource Adequacy Subcommittee meetings suggest that there will be a differential in seasonal reserve margin requirements rather than remaining static across all seasons, Duke performed modeling that applied the current reserve margin of 9.4% to all months of the year, clearly at odds with all indications from MISO.[7] MISO has not yet determined the winter planning reserve margin for the first year of implementation (which MISO has requested to be, if approved, 2023-2024), but our expectation is that there will likely be a differential across all seasons.

[7] We would expect that, as there is for the summer, there will also be a coincidence factor applied to each Load Serving Entity's obligations, but MISO has not indicated what that factor might be.

In the IRP Duke said:

> *Duke Energy Indiana also continues to monitor potential policy changes from MISO that could impact the capacity needs to maintain system reliability. MISO has proposed a new seasonal accreditation capacity (SAC) construct in late 2021. The specifics of the proposal have been under development as we have prepared this IRP. Although Duke Energy Indiana knows there will be impacts from these proposed changes and SAC could require additional capacity resources, the Company does not currently have clarity around the specific impacts to resource requirements.*[8]

In previous comments for Indiana utility IRPs, we have recommended against a base case assumption of a monthly or seasonal RA construct, because it does not meet the criteria of the IRP Rule at 170 IAC 4-7-4(25)(D). The likelihood of changes to MISO's RA construct have certainly increased since prior years, though the details of those changes remain uncertain. We continue to believe it is best practice to explore differing RA assumptions, including modeling the proposed construct as closely as possible. In the IRP narrative, Duke said, "While we do know there will be impacts that could require additional capacity resources, Duke Energy Indiana does not currently have clarity around the specific impacts to our resource requirements such that it could be included in the modeling of this IRP."[9] Still, it is not clear why those lack of specifics should impact the accreditation assumptions of thermal units more than the planning reserve margin assumption. As we encouraged Duke to do throughout the stakeholder process, it should have made its best attempt at modeling both the current construct and these anticipated changes to capture the impacts of a policy that will have a significant impact on Duke's system.

Duke also did not attempt to represent MISO's proposed thermal accreditation methodology – seasonal accreditation capacity ("SAC"). Because the proposed changes in thermal accreditation will have the largest deleterious impact on poorly performing thermal units, we are concerned that by *not* using MISO's proposed SAC methodology that the model would retain poorly performing thermal units, since their contribution to the winter reserve margin is overstated.

3.2 Limitations and Flaws in Resource Selection

Duke made several problematic and/or misrepresented modeling assumptions related to new renewable, thermal, and storage resources including:

- Assuming that the 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,

[8] Duke Energy Indiana 2021 IRP, page 18.

[9] Duke Energy Indiana 2021 IRP, page 48.

- 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.

3.2.1 Solar Investment Tax Credit

One of the items that we provided feedback on to Duke during the IRP stakeholder process is the manner in which the ITC would be applied to solar and battery paired with solar projects. During the stakeholder process, we understood Duke to say that it would monetize the ITC – meaning that it would credit its value to the first year of the project. However, after the IRP was filed and through discovery, Duke said that it accounted for the ITC by adjusting the fixed charge rate for solar resources for a tax equity partnership and then normalized, or spread the ITC, across the entire life of a project.[10] This approach appears to be conflating monetization and normalization. By normalizing the ITC, the value of the ITC is reduced due to discounting. This can have important implications for whether the IRP model picks solar or not and ignores the opportunities Duke has to leverage the ITC either through PPAs, tax equity partnerships, etc. Duke's application of the ITC to new solar and solar hybrid resources overstates the costs of those resources and has the potential to bias the model against selecting more solar resources.

3.2.2 Capacity Credit for Solar and Wind Resources

Duke modeled the capacity credit for both solar and wind resources in a manner that undervalues both resources. As discussed in the previous section, Duke modeled only a portion of MISO's proposed seasonal construct and accreditation changes. Duke modeled a seasonal capacity credit for solar resources and applied the reserve margin requirement to all months of the year.

However, the solar capacity credit used in Duke's modeling was different than that described in the IRP. In its IRP, Duke says that it accredited solar at 50% of its nameplate capacity during the summer season (which is MISO's present approach).[11] Confidential Table 5, below, shows how the capacity credit was actually assigned to solar resources in EnCompass. The summer capacity values declined based on the solar penetration level.

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[10] Duke Response to CAC Informal Discovery 6.7.

[11] Duke Energy Indiana 2021 IRP, page 90.

Confidential Table 5. Duke's Modeling of Solar Summer Capacity Credit

	MW of Solar Added	Capacity Credit (%)
Block 1	<1500	[redacted]%
Block 2	>1500 and <3000	[redacted]%
Block 3	>3000	[redacted]%

The first 1500 MW of solar was assigned a [redacted]% capacity credit, the next 1500 to 3000 MW was assigned a [redacted]% capacity credit, and any solar above 3000 MW was assigned a [redacted]% capacity credit. The average is then applied to all resources, so the average capacity for 4000 MWs of solar would be (1500 * [redacted]%) + (1500 * [redacted]%) + (1000 * [redacted]%) / 4000 = [redacted]%. That average capacity credit of [redacted]% is then applied equally to all the solar resources.

Even though Duke modeled a seasonal capacity credit for solar resources, Duke did not do the same for wind resources. Instead, Duke only assumed wind's summer capacity credit of 13% applied to all months of the year. By doing this, Duke failed to consider the seasonal accreditation benefits of wind resources in the winter months when wind typically produces more energy and will have a higher accredited value. We expressed concern to Duke about this potential bias against wind resources throughout the IRP stakeholder process, and Duke did respond by including a sensitivity that included a winter seasonal capacity credit for wind resources. However, we recommended that this assumption be included with the other modeling assumptions and not relegated as a sensitivity if it is Duke's intention to try to model the proposed MISO seasonal construct. Furthermore, we find that Duke modeled the winter capacity credit of wind resources below the value MISO has found in its own studies. MISO's Proof of Concept ("POC") initially assumed a 20% capacity credit for wind in the winter and 5% capacity credit for solar in the winter. Upon completing a preliminary evaluation of renewable accreditation, MISO found that wind had a winter capacity credit of 28.6%.[12]

In addition to our recommendation that Duke apply the appropriate seasonal accreditation for wind resources, we also recommend that Duke model at least a 5% capacity value for solar resources in the winter months in its base case based on the current guidance from MISO.

3.2.3 Costs Shared in Stakeholder IRP Meeting

During the fourth IRP stakeholder meeting, Duke presented costs of new generation from the 2021 Annual Energy Outlook ("AEO") and indicated whether those costs were lower or higher than other cost estimates it had acquired from Burns & McDonnell ("B&M") and Guidehouse. Table 6 shows the information Duke presented during this stakeholder meeting. ***Confusingly, the information provided did not convey the costs that Duke would actually model, and so stakeholders never had an opportunity to provide input on the capital costs Duke intended to use***. Knowing *whether* modeled costs are lower or higher is not tractable information, as it

[12] RAN Renewable Impact Analysis Tariff Review Workshop. September 8, 2021.

matters *how much* lower or higher they are. In the case of the larger combined cycle unit, the same unit type included in Duke's Preferred Plan, Duke's capital cost assumption was $[redacted]/kW or [redacted]% less than the AEO value reported during the stakeholder workshop.

Table 6. Duke Cost of New Generation IRP Stakeholder Workshop[13]

Techology	Size (MW)	Overnight Cost ($/kw)	VOM ($/MWh)	FOM ($/kw-yr)	Heat Rate (MMBtu/MWh)		B&M and Guidehouse costs relative to AEO 2021 Costs
Combined Cycle	1083	957	1.88	12.26	6.37		Lower capital costs; similar operations
Combustine Turbine	237	709	4.52	7.04	9905		Lower capital costs; less efficient
Nuclear	600	6183	3.02	95.48	10455		Lower capital costs; less efficient
Battery	50	1165	0	24.93	N/A		Higher capital costs; lower ongoing costs
Wind	200	1846	0	26.47	N/A		Lower costs; higher ongoing costs
Solar w/Tracking	150	1248	0	15.33	N/A		Higher capital costs; lower ongoing costs
Solar w/Storage	150	1612	0	32.33	N/A		Higher capital costs; higher ongoing costs

There are other substantial differences in combustion turbine ("CT"), solar, wind, and battery storage costs between those given during the stakeholder workshop and those that Duke actually modeled. For example, the battery storage cost reported to stakeholders was $1,165 per kW, but the modeled cost was $[redacted] per kw, a [redacted]% increase. Table 7 shows the comparison of the capital costs that Duke presented in the IRP stakeholder workshop against the capital costs that Duke reported in the IRP.

Table 7. Comparison of Duke Presented Capital Costs to IRP

	Presented by Duke[14]	**Duke Reported in IRP**[15]
Combined Cycle	$957	$[redacted] (F-Class) or $[redacted] (J-Class)
Combustion Turbine	$709	$[redacted]
Nuclear	$6,183	$[redacted]
Battery	$1,165	$[redacted]
Wind	$1,846	$[redacted]
Solar w/ Tracking	$1,248	$[redacted]
Solar w/ Storage	$1,612	$[redacted]

Had there been a chance to comment on Duke's actually costs, we certainly would have done so, but Duke never sought feedback on these important assumptions.

[13] Duke IRP Stakeholder Meeting #4, slide 17. Retrieved from https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/dei-irp-2021/workshop-04/dei-irp-sh-mtg.pdf?la=en&rev=48c81a7f144244dda2fab78e7cf0f995

[14] Duke IRP Stakeholder Meeting #4, slide 17. Retrieved from https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/dei-irp-2021/workshop-04/dei-irp-sh-mtg.pdf?la=en&rev=48c81a7f144244dda2fab78e7cf0f995

[15] Duke Energy Indana 2021 IRP, Figure V.1, page 88.

3.2.4 Capital Cost of Combined Cycle

Duke's Preferred Plan includes the addition of a 1,221 MW CC gas plant in 2027. After receiving the information underlying the capital costs of this CC through informal discovery, we discovered that the capital cost that Duke modeled is unreasonably low. Table 8 shows the cost and MW size for 8 CC projects of a comparable size in neighboring states. The weighted average cost of the seven projects that are greater than 1 GW is $955/kW. Note that this comparison conservatively assumes those project costs are in the same year dollars as Duke's costs given in Figure V.1 of the IRP. Duke's modeled cost of $[redacted]/kW[16] is about [redacted]% lower than the weighted average cost of comparable projects in neighboring states.

Table 8. CC Project Costs[17]

Facility	Rating (MW)	Cost	Cost per kW
Cadiz Combined Cycle Plant (Harrison County Industrial Park)	1,050	$ 987,000	$ 940
Blue Water Energy Center (Belle River Combined Cycle Plant)	1,146	$ 1,000,000	$ 873
Indeck Niles Energy Center	1,174	$ 1,103,936	$ 940
Jackson Generation Energy Center	1,200	$ 1,224,000	$ 1020
CPV Three Rivers Energy Center	1,250	$ 1,312,500	$ 1050
Cornerstone Energy Center Project	1,800	$ 1,836,000	$ 1020
Guernsey Power Station	1,875	$ 1,600,000	$ 853
Weighted Average of Projects			$ 955

Furthermore, the data contained in Duke's Encompass files suggest that the combined cycle added in the Preferred Plan would be located at the [redacted] site. It does not appear that this site presently has the gas transportation capacity necessary to supply a 1,221 MW CC so a lateral may need to be built to supply the unit. It is not clear if that cost is included in Duke's modeled cost or not. Confidential Attachment SC 4.1-A includes a note that says the interstate gas pipeline reservation cost modeled for this unit "does not include a lateral/interstate pipeline cost." If so, this omission would likely add millions of dollars of annual cost to the CC.

3.2.5 Availability of New Resources

Figure V.1[18] in Duke's IRP purports to give the first year in which each technology type was made available for selection in EnCompass. The years provided in this figure for the new thermal resource builds do not reflect the years that were actually modeled within EnCompass. If one

[16] Duke Energy Indiana 2021 IRP, Figure V.1, page 88.

[17] Data from S&P Global.

[18] Duke Energy Indiana 2021 IRP, Figure V.1, page 88.

looks at Figure V.1, the conclusion might be that only renewables and storage were available for selection prior to 2026, but all of the new thermal resources with the exception of the 2x1 J CC could be selected in the optimized portfolios before 2026. ***Table 9 shows a comparison of what Duke reported in the IRP in Figure V.1 and what it actually modeled in EnCompass.***

Table 9. New Thermal Resource First Year Build

	CTs	2x1 F CC	2x1 J CC	Recip	CHP
Duke Reported in IRP	2026	2027	2027	2026	2026
EnCompass Modeling	2023	2023	2027	2024	2024

3.2.6 Solar Hybrid Operation

In its modeling, Duke assumed that the solar and battery resources would be paired together for the entire project life, an assumption which is far more strict than is required to be eligible for the ITC. The ITC merely requires that the battery be charged exclusively from the solar resource for the first five years of its life to receive the full ITC. Duke also developed an hourly profile that entirely fixed the operation of the solar and battery storage. This is far more constrained operation of this resource that would happen in practice and would tend to reduce the value of the project.

3.2.7 Solar Constraints

During the stakeholder process, Duke did not discuss the resource constraints it would apply to new supply-side resource options in the capacity expansion modeling. It is necessary to apply these limits in order to allow the model to solve, but these limits can also be used to unduly restrict the feasible capacity expansion plans. In the IRP, Duke stated that, "Annual capacity additions for each resource type are limited to reflect practical constraints. The MISO scenario specific resource mixes were used to guide these limitations."[19] Within EnCompass, Duke chose to model an overall constraint on new solar resources that specifies how many active projects can be in the expansion plan for each year for most of the optimized portfolios.

The concerning aspect of the constraint is that Duke changed it across scenarios. For example, under a high CC capital cost scenario, Duke manipulated the model to significantly limit how many new solar projects could be added.[20] Duke allowed EnCompass to only build 12 solar projects by 2030 (about 600 MW) under the No Carbon High CC Cost case, but it allowed the model to build 38 solar projects (about 1,900 MW) by 2030 under the Carbon High CC Cost case. It does not make sense to us that these limits would be different in these scenarios and would appear to be designed to result in the selection of two CCs CC even under a high cost

[19] Duke Energy Indiana 2021 IRP, page 90.

[20] Standalone solar projects were modeled at 50 MW sizes, and solar hybrid projects were modeled at 75 MW for the solar portion of the hybrid project.

sensitivity. Several of the No Carbon sensitivities include a similar and sometimes even tighter constraint. In general, these runs are not discussed at all in the IRP, so Duke provides no information or justification, and it is not even completely clear what these runs were used for.

3.2.8 Discount Rate

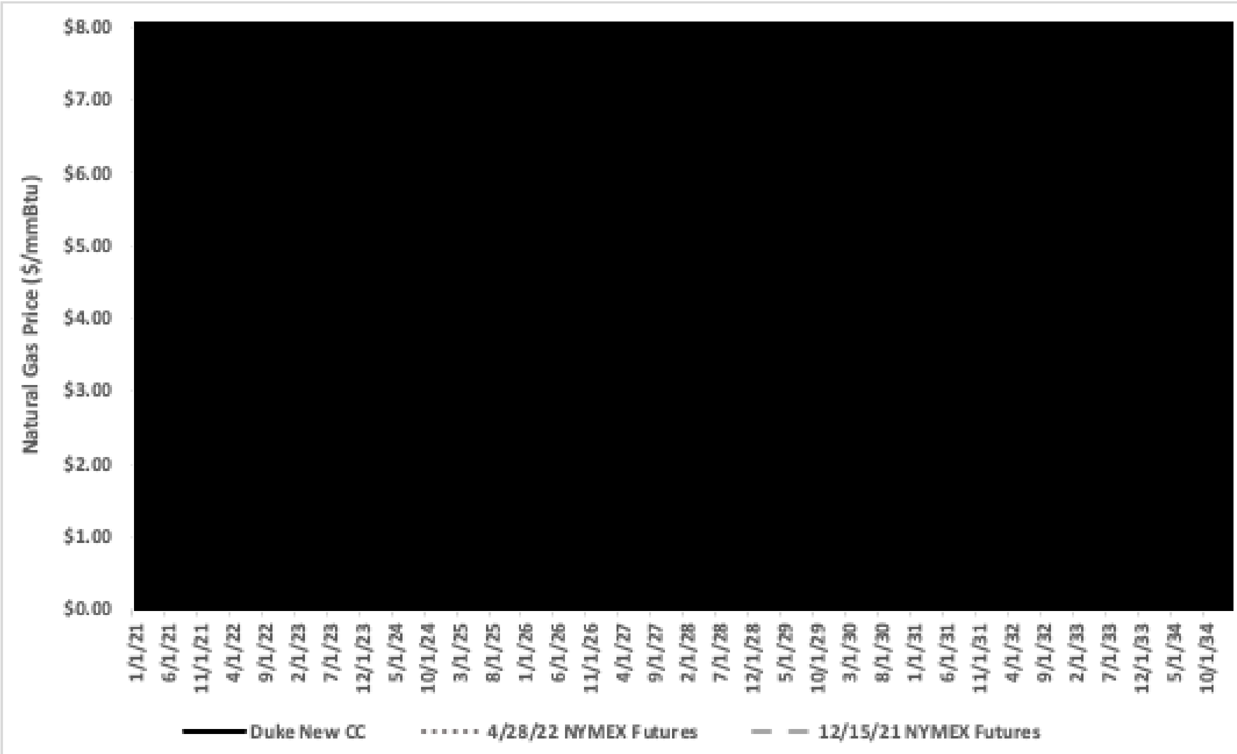
Upon receipt of Duke's modeling files, we observed that its discount rate assumption of [redacted]% was lower than we normally see for a nominal weighted average cost of capital. After some investigation into IURC orders on this point, we discovered that Duke's most recent approved WACC, as of June 2021, was 7.17%. It was also the case that the discount rate used to levelize demand-side costs was different than that use to levelize supply-side costs. We would expect to see the same rate used for all three purposes to ensure consistency throughout the analysis.

3.3 Commodity Forecasts

3.3.1 Natural Gas Price Forecast

Confidential Figure 3 shows a comparison of the natural gas price forecast that Duke modeled in EnCompass[21] for the new CC resources against the CME/NYMEX futures for gas at the Henry Hub as of April 28, 2022, and as of December 15, 2021. If you compare the January 2027 to December 2034 time period for the NYMEX futures against the gas prices that Duke modeled, Duke's forecasted prices are, on average, 17% lower than the NYMEX futures. We assume that the prices Duke modeled in EnCompass are commodity-only prices, but if they include any gas transportation costs, then the gap would be even larger.

[21] The most recent EnCompass modeling input data Duke provided was in response to CAC-EMCC Informal 1.1 G.



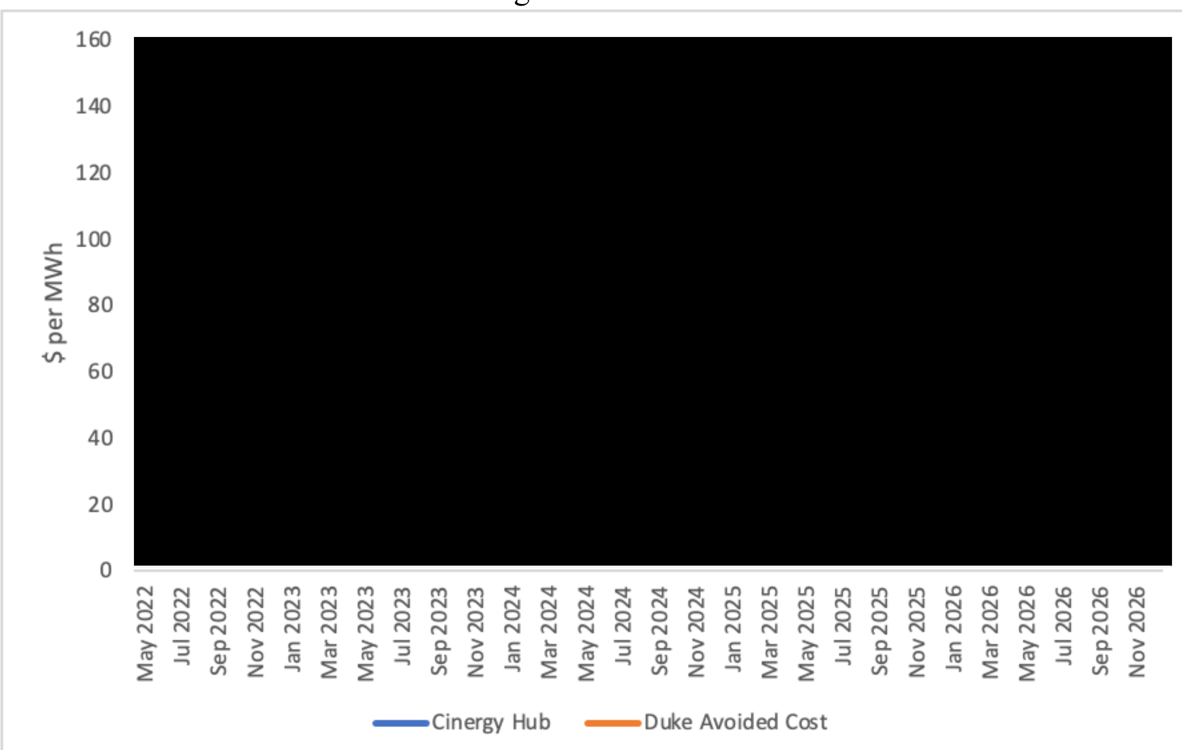
Confidential Figure 3. Natural Gas Price Forecast Comparison ($/mmBtu)

Henry Hub Futures as of December 15, 2021, the date on which this IRP was filed, also start out higher than what Duke modeled but then trend lower than Duke's forecast starting in late [redacted]. This is not to say that Duke should have or could have used natural gas futures that coincide with or post-date its IRP filing date. Rather, the point is that, as Duke moves forward with any certificate of need filings or similar approvals, its resource decisions must be reevaluated in light of myriad changed circumstances including natural gas pricing. Recent increases in natural gas prices highlight the possibility of a shifting paradigm of gas price volatility, which would be a very important consideration to explore as Duke moves forward with the CC in its Preferred Plan.

3.4 Avoided Cost

Indiana's IRP rules require "[a]n explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation." This information was not part of Duke's IRP filing, so CAC submitted a discovery question in order to get the avoided cost. However, the information provided by Duke was not accompanied by any supporting documentation.

The avoided energy cost used for screening EE measures is much lower than current Cinergy Hub futures as shown in Confidential Figure 4.



Confidential Figure 4. Comparison of Duke Avoided Energy Cost and Cinergy Hub Futures[22]

The fundamentals of electricity markets have radically changed in the past six months or so, therefore we would not expect the screening of energy efficiency that was completed over a year ago to reflect current avoided costs. However, 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. We request Duke to invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings.

[22] Informal Discovery Confidential Attachment CAC 6.12-A and Cinergy Hub futures from CME Group/NYMEX.

4 Energy and Demand Forecasts

Section 4 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-5 of the Indiana IRP Rule. Please see Table 10 below for our findings.

Table 10. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-5

IRP Rule	IRP Rule Description	Findings
4-7-5 (a)	The analysis of historical and forecasted levels of peak demand and energy usage must include the following:(1) Historical load shapes, including the following: (A) Annual load shapes; (B) Seasonal load shapes; (C) Monthly load shapes; (D) Selected weekly load shapes; and (E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	**Mostly**
4-7-5 (a)	(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	**Met**
4-7-5 (a)	(3) Actual and weather normalized energy and demand levels.	**Met**
4-7-5 (a)	(4) A discussion of methods and processes used to weather normalize.	**Met**
4-7-5 (a)	(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	**Met**
4-7-5 (a)	(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system; (B) Customer classes, rate classes, or both; and (C) Firm wholesale power sales.	**Met**
4-7-5 (a)	(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	**Not Met**
4-7-5 (a)	(8) Justification for the selected forecasting methodology.	**Not Met**
4-7-5 (a)	(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	**Met**
4-7-5 (a)	(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.	**Met**
4-7-5 (b)	To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable peak demand and energy use forecasts.	**Partial**
4-7-5 (c)	In determining the peak demand and energy usage forecast to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider likely based on alternative assumptions such as (1) Rate of change in population; (2) Economic activity; (3) Fuel prices, including competition; (4) Price elasticity; (5) Penetration of new technology; (6) Demographic changes in population; (7) Customer usage; (8) Changes in technology; (9) Behavioral factors affecting customer consumption; (10) State and federal energy policies; and (11) State and federal environmental policies.	**Partial**

4.1 Load Forecast

4.1.1 Information Provided in the IRP

Duke's IRP and Appendix B contain limited information about Duke's load forecast. It is our understanding that Duke utilizes Itron's Statistically Adjusted End-Use ("SAE") forecasting methodology to develop the forecasts. In order to meet Indiana's IRP rules, most Indiana utilities will include a discussion about their methodology and the key variables that are included in the model used to develop the forecasts. Duke did not do this.

4.1.2 Energy and Peak Demand Forecasts

Figure 5 and Figure 6 show Duke's energy and peak demand forecast for the low, base, and high forecasts, respectively. Duke has a near term spike in energy and demand from the addition of new wholesale customers.[23] The forecasts then drop nearly 500 MW[24] due to the loss of customers between 2025 and 2028. [25]

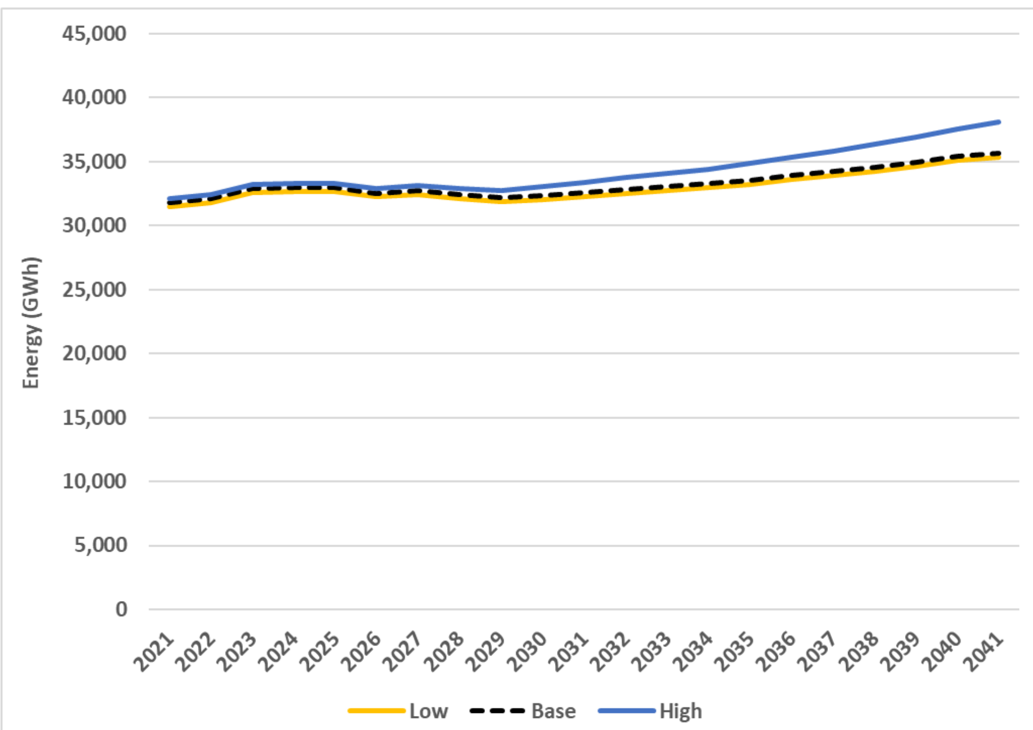


Figure 5. Duke Energy Forecasts (GWH)

[23] Approximately a 300 MW increase in peak from 2022 to 2023.

[24] Duke Energy Indiana 2021 IRP, page 156.

[25] CAC Informal Discovery 6.6a and 6.6b.

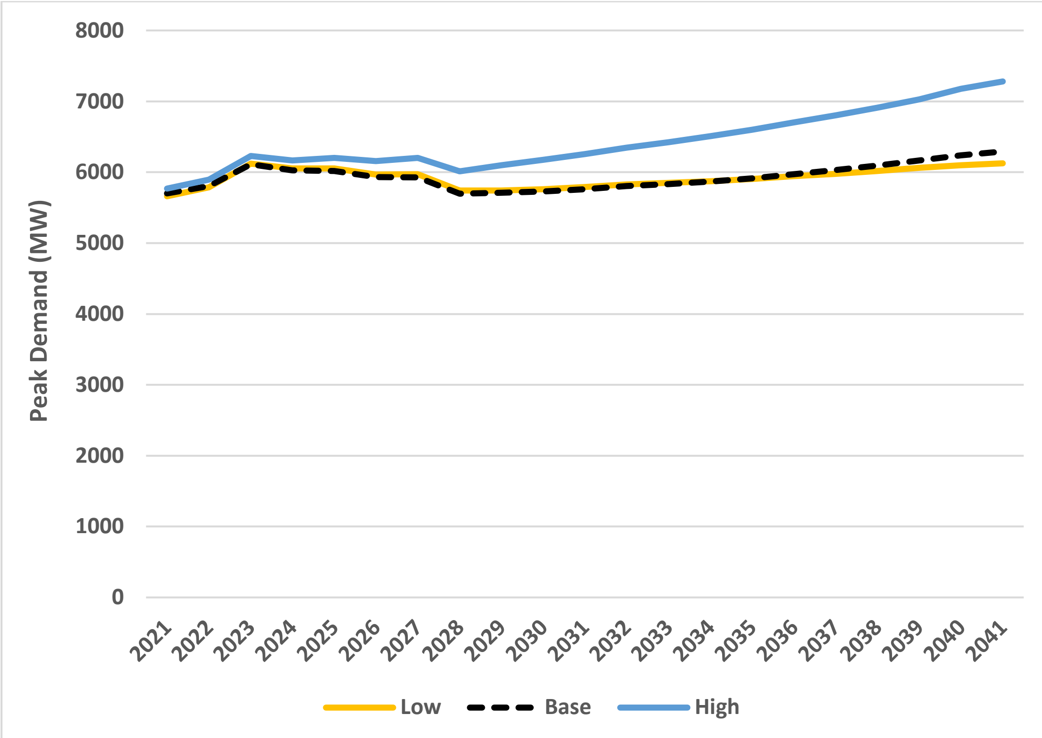


Figure 6. Duke Peak Load Forecasts (MW)

Table 11 shows the average annual growth for the energy and peak forecasts across the three forecast scenarios. The average annual growth for energy is the same in both the low and base energy forecasts. There is a slight difference in the average annual growth for the peak demand between the low and base forecasts. As one can see in the figures, the base and low forecasts do not differ as much as the base and high forecasts do. Indeed, the low and base forecasts largely only differ in terms of peak, not energy.

Table 11. Energy and Peak Average Annual Growth Rates (%) for 2021 to 2041

	Low	Base	High
Energy	0.59%	0.59%	0.87%
Peak	0.41%	0.51%	1.18%

Figure 7 shows the annual percentage difference between the base and low forecasts compared to the base and high forecasts. While we would not expect to see the same difference in growth rate between the base and high forecasts and the low and base forecasts as it is our understanding that the high case assumes higher levels of electric vehicle penetration, the difference between the low and base is almost negligible, severely limiting the usefulness of the low forecast sensitivity. As is clearly evident from Figures 5, 6, and 7, the low forecast does not capture much downside risk to Duke's load forecast. For example, Duke could create a forecast that captures the risk of further loss of wholesale load.

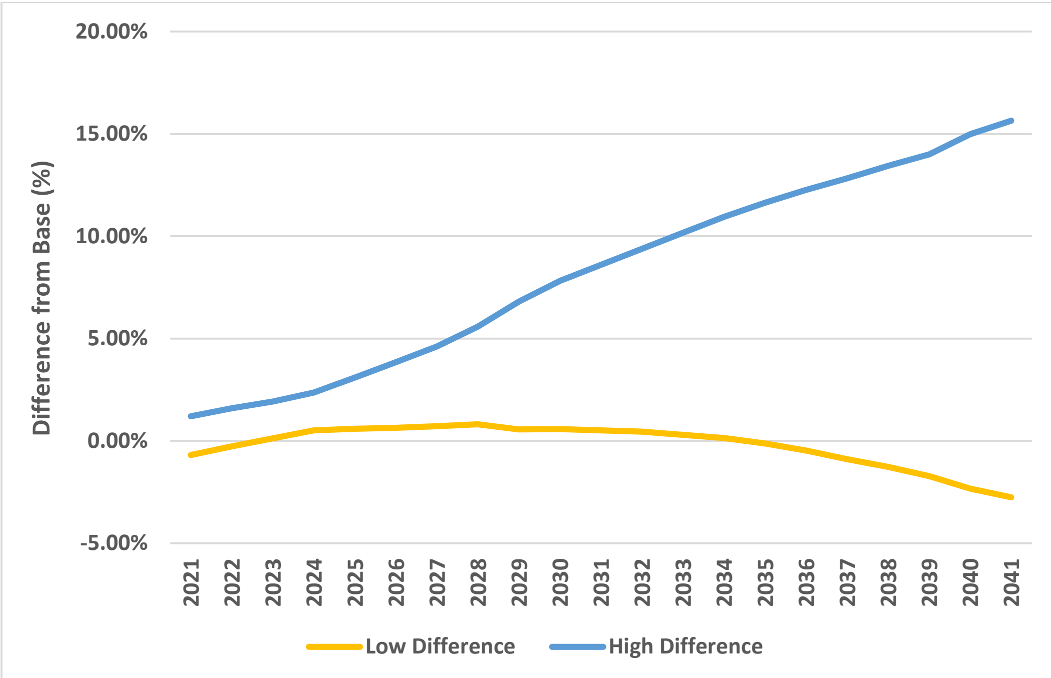


Figure 7. Annual Percentage Difference in Base and Low Peak Forecasts

5 Description of Available Resources

Section 5 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-6 of the Indiana IRP Rule. Please see Table 12 below for our findings.

Table 12. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-6

IRP Rule	IRP Rule Description	Findings
4-7-6 (a)	In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated: (1) The net and gross dependable generating capacity of the system and each generating unit.	**Not Met**
4-7-6 (a)	(2) The expected changes to existing generating capacity, including the following: (A) Retirements; (B) Deratings; (C) Plant life extensions; (D) Repowering; and (E) Refurbishment.	**Met**
4-7-6 (a)	(3) A fuel price forecast by generating unit.	**Met**
4-7-6 (a)	(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; (D) subsequent disposal; and (E) water consumption and discharge at each existing fossil fueled generating unit.	**Partial**
4-7-6 (a)	(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) and energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	**Partial**
4-7-6 (a)	(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	**Partial**
4-7-6 (b)	In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	**Partial**
4-7-6 (b)	(2) For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters; (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined; (C) The customer class or end-use, or both, affected by the demand-side resource; (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings; (E) The estimated impact of a demand side resource on the utility's load, generating capacity, and transmission and distribution requirements; (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	**Partial**
4-7-6 (b)	(3) For potential supply-side resources, the utility shall include the following: (A) Identification and description of the supply-side resource considered; (B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost; (C) A description of significant environmental effects.	**Met**

4-7-6 (b)	(4) In analyzing transmission resources, the utility shall include the following: (A) The type of the transmission resource; (B) A description of the timing, types of expansion, and alternative options considered; (C) The approximate cost of expected expansion and alteration of the transmission network; (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources; (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	**Partial**

5.1 ENERGY EFFICIENCY

5.1.1 Market Potential Study

Duke Energy Indiana engaged with Nexant, Inc., in October 2020 to determine the potential energy and demand savings that could be achieved by demand-side management ("DSM") programs. DEI and Nexant sought input from members of the DEI DSM Oversight Board ("OSB") throughout the development of the market potential study through its completion in March 2021. CAC found the development process to be open and collaborative. DEI and Nexant were responsive to comments and incorporated many of the recommendations provided by CAC.

The market potential study quantified the technical, economic, and achievable savings for the years 2021 through 2045. Achievable savings were further analyzed and grouped into five scenarios as follows:

- **Base scenario with all customers** – includes all the customers in Duke Energy's Indiana service territory and includes existing EE programs and measures currently offered by DEI.
- **Base scenario excluding opt-outs** – aligns with existing program portfolio excluding customers currently opted-out and includes existing EE programs and measures currently offered by DEI.
- **Enhanced scenario with expanded measures** – includes existing EE programs with measure bundles that include current and newly proposed measures, as well as new EE programs where measures included in the study did not logically fit into an existing offering.
- **Enhanced scenario with increased spending** – aligns with enhanced scenario with expanded measures but increases program spending via increasing incentives as an approximation of higher program participation.
- **Avoided cost sensitivity** – aligns with enhanced scenario with expanded measures, with enhanced EE benefits that would occur if avoided energy costs were higher than current values. Measures are re-screened from Utility Cost Test ("UCT") perspective with a 50% increase in avoided energy costs.

5.1.1.1 Measure Savings Assumptions

The savings algorithm for the measures included in the market potential study are based on Technical Reference Manuals ("TRM") from six states: Indiana, Illinois, Iowa, Michigan, Wisconsin, and Minnesota given that the most recent Indiana TRM (version 2.2) was last updated in 2015. The TRMs from the other states had all been updated in 2020 at the time of the MPS development. Each of these states has a process for annual updates and revises their TRMs to ensure that the assumptions match current conditions for technology capabilities, use cases, saturation, and many other factors. This process is important to ensure that deemed savings estimates, based on a TRM, are reasonable and realistic. Unfortunately, Indiana currently lacks a process to update the statewide TRM, but CAC understands discussions are underway to address this and the state of the Indiana TRM.

Even though the Indiana TRM is significantly outdated, the MPS analysis included several measure characterizations and assumptions from the Indiana TRM. In most cases, the same measures and assumptions were available from a neighboring state's TRM within comparable climate zones as DEI's service territory. While the number of MPS measures relying on the Indiana TRM is relatively limited, the impact can still be considerable since some measures are high volume. We request that Duke invite stakeholders to the table well in advance of its upcoming DSM filing to address this issue and work on a solution together.

5.1.1.2 Emerging Technology

The MPS analysis included approximately forty measures that were classified by Nexant as emerging technology. These measures were identified using a variety of resources including the American Council for an Energy-Efficient Economy ("ACEEE"), the U.S. Department of Energy, and Bonneville Power Administration. CAC commends the research undertaken by Nexant to identify and evaluate emerging technology measures. Unfortunately, many of the emerging technology measures included in the study failed to pass the economic screen and therefore did not contribute to the achievable potential. The nature of new emerging technology is such that high initial costs tend to fall as production volume and customer adoption increase. The MPS analysis made no accommodation for any emerging technology to be included in the later years of the analysis if/when the measure becomes cost effective. New technologies are regularly being introduced, and many utility programs contribute to the market readiness of these emerging technologies through pilot programs and incentives. Failure to account for these technologies results in a conservative and unrealistic view of the potential savings. We request that Duke invite stakeholders to the table well in advance of its upcoming DSM filing to address this issue and work on a solution together.

5.1.2 Cost of Energy Efficiency Bundles Modeled in EnCompass

Our review of Duke's energy efficiency modeling found that Duke misreported in its IRP narrative how it modeled the cost adjustments for the energy efficiency bundles, which could result in the model being biased against selecting energy efficiency. For this IRP, Duke modeled the Expanded Measure and the Expanded Measure + Higher Avoided Cost scenarios from the Market Potential Study. In order to ensure the energy efficiency bundles were available for selection across the entire planning horizon (2021 – 2050 for capacity expansion runs), Duke modeled bundles for 2024 – 2026, 2027 – 2034, 2035 – 2042, and 2043 – 2050. Duke also forced in an energy efficiency bundle that represented the savings of the 2021 – 2023 DSM plan including income qualified program savings. Based on the bundle time horizons, and the two different savings level scenarios modeled, EnCompass had the choice to select no energy efficiency bundles, the Expanded Measure savings bundles, or the Expanded Measure + Higher Avoided Cost bundles. Based on a review of the bundles, we found that the IRP bundles appropriately aligned with the savings identified by the MPS.

While we commend Duke for modeling the energy efficiency bundles on a levelized cost basis, which allows the model to capture the lifetime cost and benefits of energy savings in the same way it does for supply-side measures, we did find an issue with how the bundle costs were modeled. In the IRP narrative, Duke discussed the levelized cost of the energy efficiency bundles and stated that:

> *These levelized costs were adjusted to cover the costs of program overhead and utility incentives and then credited with savings associated with avoided Transmission and Distribution costs.*[26]

However, in our review of the EnCompass modeling inputs[27] and the underlying workbooks that Duke used to develop the levelized costs for the energy efficiency bundles, we realized that Duke did not model the energy efficiency bundle costs adjusted for these avoided costs, program overhead, and incentives within EnCompass. It was our understanding that Duke was going to model energy efficiency bundle costs with an adjustment for the avoided transmission and distribution ("T&D") benefits, but Duke did not.

Duke provided CAC with several workbooks showing how the levelized bundle costs were calculated in response to informal discovery question CAC 6.18. After reviewing the workbooks provided in response to CAC 6.18, we could see that Duke did not model the energy efficiency adjusted bundle costs within EnCompass. Had Duke included all these adjustments, it would have resulted in a lower $/MWh levelized cost for energy efficiency, which means that the costs modeled by Duke in EnCompass were higher than they should have been.

[26] Duke Energy Indiana 2021 IRP, page 222.

[27] The most recent EnCompass modeling input data Duke provided was in response to CAC-EMCC Informal 1.1 G.

Table 13 below shows the cost comparison for each bundle and each MPS scenario modeled in EnCompass. The column labeled "Duke Modeled" represents the levelized cost that Duke modeled in EnCompass for each bundle, and the column labeled "Duke Adjusted" represents the bundle costs that are adjusted for shareholder incentives, administrative overhead, and the avoided T&D benefit. Based on the information in Duke's workpapers and Duke's description of how it was going to model the cost of the energy efficiency bundles, the costs put into EnCompass should have reflected these adjustments.

This implies that the net change after the adjustments results in lower levelized costs for both the Expanded Measure and the Expanded Measure + Higher Avoided Cost scenarios modeled in EnCompass. By modeling energy efficiency costs as more expensive than they actually are, Duke misrepresented the costs of the energy efficiency bundles included in its IRP portfolios and potentially biased the model against selecting energy efficiency.

Table 13. Energy Efficiency Bundle Cost ($/MWH) Comparison

EE Bundle	Duke EE Scenario	Duke Modeled	Duke Adjusted[28]
2024 - 2026 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]
2027 – 2034 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]
2035 – 2042 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]
2043 – 2050 Bundles	Expanded Measure	$[redacted]	$[redacted]
	Expanded Measure + Higher Avoided Cost	$[redacted]	$[redacted]

Another concern we have about the energy efficiency bundles is related to the application and use of the line loss factor to convert savings from the meter to the generator. In developing the DSM inputs for the Company's IRP, DEI quantified the energy savings at the generator by applying a line loss factor of [redacted]% as follows:

$$Energy\ Savings\ at\ Generator = Energy\ Savings\ at\ Meter\ \times\ (1 + Line\ Loss\ Factor)$$

This application of the line loss factor was incorrect since line losses are measured with respect to the generator, not the meter. A correct application of the line loss factor would be:

$$Energy\ Savings\ at\ Generator = Energy\ Savings\ at\ Meter\ \div\ (1 - Line\ Loss\ Factor)$$

As a result of the misapplication of the line loss factor, the energy savings at the generator were modestly underestimated. To demonstrate the effect of this error, the calculation below shows the generator savings using the DEI LLF approach and correct LLF approach for the *Expanded Measures* scenario in the year 2024.

[28] Duke's confidential workpapers provided in response to CAC Informal Discovery 6.18.

DEI LLF approach: $190{,}377\ MWh\ \times\ (1+0$,[redacted]$)=204{,}522\ MWh$

Correct LLF approach: $190{,}377\ MWh\ \div\ (1-$[redacted]$)=205{,}657\ MWh$

Additionally, the line loss factor used by DEI appears to represent average system losses over the course of a year. Since energy efficiency savings occur at the margin, and line losses grow exponentially with load (I^2R), the use of average line losses undervalues the avoided costs associated with energy efficiency. CAC recommends that *marginal* line losses be used in the calculation of avoided costs. A report by the Regulatory Assistance Project ("RAP") entitled *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* found that "When compounded with the avoided marginal line losses, energy efficiency measures can save about 1.4 times as much capacity at the generation level as is measured at the customer's meter." This report can be downloaded at https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

We reiterate our request that Duke invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings.

5.2 DEMAND RESPONSE

We reviewed Duke's tariff pages, its demand response customer-facing webpages, and information in the IRP about its demand response ("DR") programs. We have the following recommendations for future improvement to Duke's DR programs:

- Duke's DR pilots can add to future potential demand response and should be explored in updated modeling for that purpose.
- It is clear that Duke expects that winter peaks will be rising in the future, so more effort toward winter demand response programs/sign ups should be encouraged.
- Duke should work with interested stakeholder and/or its DSM Oversight Board to develop a plan for continued engagement of its customers to make sure response to calls will continue in the future.
- Duke should be calling its DR programs multiple times throughout the year, not just once and definitely not all at once.

We request that Duke continue this conversation with the DSM Oversight Board and/or with other interested stakeholders within the next 6-9 months to expand its DR programming and achievement.

6 Selection of Resources

Section 6 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-7 of the Indiana IRP Rule. Please see Table 14 below for our findings.

Table 14. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-7

IRP Rule	IRP Rule Description	Finding
4-7-7	To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	**Mostly**

6.1 RESOURCE SCREENING TABLE

Duke includes a section within the IRP that discusses the resource screening process used to determine which resources are ultimately modeled within EnCompass. We found certain aspects of the IRP narrative to be confusing with regard to which resources were screened in and out of being included as a potential option in EnCompass. In one section of the discussion regarding which resources were included, Duke said:

> *Although flow batteries' capital costs project to be higher than Li-Ion batteries, flow batteries project to become most effective as the duration of the battery is increased due to energy capacity being dictated primarily by the size of the tanks. Therefore, flow batteries have been included in the technology options as a longer duration storage option. Although flow batteries are included as a technology option, the models did not select the technology due to 6-hour Li-Ion batteries being more economical for storage applications longer than 4 hours.*[29]

Duke then lists the resources that were modeled as new supply side resource options in EnCompass, and neither flow batteries nor 6-hour Li-Ion batteries were included. The only resources modeled in EnCompass were a standalone battery storage resource as well as a paired 4-hour Li-Ion battery storage resources.[30]

Another confusing aspect about the resource screening process is that Duke included Small Nuclear Reactors ("SMR") as a resource alternative in EnCompass. Duke said that,"The first NuScale[31] module is expected to reach commercial status in the late 2020s timeframe."[32] It seems that Duke is passing this technology through the screening process even though there are questions on the cost of this technology and whether or not it will be commercially viable. Duke

[29] Duke Energy Indiana 2021 IRP, page 176.

[30] The battery storage resource is paired with a solar resource.

[31] Duke says that NuScale Power is the leader in SMR design and licensing in the US.

[32] Duke Energy Indiana 2021 IRP, page 175.

also said that, "In a carbon-constrained future SMRs and combined cycle with Carbon Capture and Utilization and Storage (CCUS) are likely to be competitive in the post-2030 timeframe."[33] If that is the criteria for determining which resources would be modeled in EnCompass, then longer duration battery storage resources that are far less speculative and risky should have also been passed to the EnCompass modeling step from the screening process as well.

[33] Duke Energy Indiana 2021 IRP, page 178.

7 Resource Portfolios

Section 7 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-8 of the Indiana IRP Rule. Please see Table 15 below for our findings.

Table 15. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-8

IRP Rule	IRP Rule Description	Finding
4-7-8 (a)	The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider the following: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	**Partial**
4-7-8 (b)	With regard to candidate resource portfolios, the IRP must include: (1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.	**Partial**
4-7-8 (b)	(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	**Partial**
4-7-8 (b)	(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	**Partial**
4-7-8 (c)	Considering the analyses of its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information: (1) A description of the utility's preferred resource portfolio.	**Met**
4-7-8 (c)	(2) Identification of the standards of reliability.	**Met**
4-7-8 (c)	(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	**Met**
4-7-8 (c)	(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	**Partial**
4-7-8 (c)	(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	**Partial**
4-7-8 (c)	(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	**Not Met**
4-7-8 (c)	(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio; (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule; (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio; and (D) The utility's ability to finance the preferred resource portfolio.	**Partial**
4-7-8 (c)	(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following: (A) Quantification, where possible, of assumed risks and uncertainties and (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	**Not Met**

4-7-8 (c)	(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	**Met**
4-7-8 (c)	(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following: (A) Demand for electric service; (B) Cost of a new supply-side resources or demand-side resources; (C) Regulatory compliance requirements and costs; (D) Wholesale market conditions; (E) Changes in Fuel costs; (F) Changes in Environmental compliance costs; (G) Technology and associated costs and penetration; (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	**Partial**

7.1 CANDIDATE PORTFOLIOS

Similar to the 2018 IRP, Duke developed three categories of candidate portfolios, which included economically optimized portfolios, hybrid portfolios that combined fixed and optimized resources, and stakeholder portfolios. Table 16 highlights the 12 total portfolios that Duke evaluated for this IRP. Duke modeled these portfolios under the scenarios of Reference Case without Carbon, Reference Case with Carbon, high gas prices, and low gas prices. Duke also modeled a few sensitivities which included low, high, and climate change load, applying Duke's RFI data for solar resources, a higher capital cost for the new gas resources, and a winter wind capacity credit.

Table 16. Duke Portfolios

Optimized Portfolios	Hybrid Portfolios	Stakeholder Portfolios
Reference without CO_2 Regulation	Balanced	Biden 100
Reference with CO_2 Regulation	Renewables/CC	Biden 90
High Gas Prices	Renewables/CC/CT*	Environmentally Focused
Low Gas Prices	Renewables/CT	Reliable Energy

**Duke's Preferred Plan*

It is our understanding that virtually all of these portfolios, even the so-called "stakeholder" portfolios were created by Duke, as they should be. It is extremely difficult to create meaningful portfolios in a vacuum of information about the relative costs of resources, the economics of retiring existing units, etc.; that is the primary function that using a model like EnCompass serves. We made some high level suggestions about some of the big picture assumptions, e.g. that Duke look at a Biden 90 scenario as well as a Biden 100 scenario. But we want to be clear that this is not an endorsement by us or any of our clients of Duke's path to meet these goals. For example, the Biden 100 portfolio includes a new combined cycle in 2023. We do not see building a large thermal plant as a sensible bridge to a carbon free system, and it certainly would not be possible to build such a facility in just a year.

7.2 SCORECARD CRITERIA

Duke evaluated several different metrics in the IRP Scorecard evaluation. These metrics included reliability, resilience/stability, affordability, environmental sustainability, and portfolio flexibility. Duke then created criteria to evaluate each of these metrics. Table 17 shows each of the criteria for the five metrics. We have concerns about several of the criteria used for the metrics.

Table 17. Duke's IRP Scorecard Criteria[34]

Metrics	Criteria
Reliability	Dispatchable resources as a percentage of load in 2030
	Can portfolio serve load in all years of IRP planning period?
	Average percentage of annual market purchases in all years and scenarios
Resilience/Stability	Diversity of resources as measured by Herfindahl – Hirschman Index ("HHI")
	Executability*
	Can 2030 portfolio mix serve load in extreme weather weeks in Portfolio Screening Tool ("PST")?*
Affordability	Average of portfolio PVRRs across scenarios
	5-year Compound Annual Growth Rate ("CAGR") of rates in Ref Scenario w/o CO_2
Environmental Sustainability	2040 CO_2 percentage reduction and average annual tons emitted
	On track for meeting Duke Energy Climate goals?
	SO_2, NOx, PM and water emissions* in 2030
Portfolio Flexibility	Range of PVRRs across scenarios

**Scored qualitatively*

7.2.1 Reliability Metric

First, the reliability metric does not actually measure the reliability of a generation portfolio in a manner that is typical to answer such a question. Duke'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. Duke assumes that if this metric is below 0.5%, then there is no concern. 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%.

[34] Duke 2021 IRP, Table V.1, page 109.

The reliability metric also considers the average of market purchases in all years across all scenarios modeled. We have concerns about this use of this criterion for a reliability metric, because some of the runs allowed for hourly purchases and sales of up to [redacted] MW, roughly the size of Duke's peak load. Certain portfolios may be predicated on an assumption of purchases that is not realistic and is risky, but then can also be penalized for that assumption.

We also have some concerns around using the 2030 thermal and battery storage resources divided by the 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 the system conditions in 2030. It is also not clear if this metric is looking at Duke's peak load before energy efficiency or if it includes the reduction from energy efficiency measures.

7.2.2 Resilience/Stability Metric

A portion of the Resilience/Stability Metric is measured by the application of the Herfindahl-Hirschman Index ("HHI") to technology diversity. As Duke describes it, "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."[35] As discussed in the stakeholder workshops, the metric was to apply to the square of the capacity of each resource and *not* to aggregated capacity across each resource type. Our preference would be for 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. A bigger picture concern is that it is not clear what risk this metric is intended to measure and whether there might be better ways to get at it. For example, if it is fuel risk, a probabilistic or sensitivity simulation would better account for that risk. If the risk that Duke wants to capture is lulls in renewable generation, an analysis of those events along with correlated load and non-renewable generator performance would better account for that risk.

A second component of this metric was performance of portfolios during extreme weather events using a tool Duke created for this purpose. We acknowledge the work that Duke put into developing the Portfolio Screening Tool ("PST") presented to stakeholders during the IRP workshops, and we are certainly not opposed to the idea of testing portfolios under different weather events, which aligns with our previous recommendation on this issue. However, the PST is not the tool for that purpose, and therefore we are concerned about its use in the scorecard for the Resilience/Stability metric. The PST is limited in that it does not take into consideration any load growth or savings from new energy efficiency programs. We made this point to Duke during one of the stakeholder workshops, and Duke's response was essentially that including energy efficiency would not have a large impact on the result. We would like to see Duke back that assertion up with quantitative data. Typically, load increases during severe weather events

[35] Duke Energy Indiana 2021 IRP, page 111.

such as polar vortices. The impact of energy efficiency also increases during these events.[36] The winter week included in the PST includes a polar vortex event.[37] The tool could helpfully conceptualize EE's increasing impacts during such events if it had been properly included.

Another concern with the PST is how realistically it represents the dispatch of thermal generators. Duke's generators are offered into MISO, and but for Duke's self-commitment practices, it is MISO that determines whether to commit and dispatch those units. Also, Duke seems to be ignoring the likelihood of correlated failures.[38] For example, the tool appears to assume that Duke's combined cycle unit, Noblesville, operated at full output or 310 MW for the entire winter period. The reality, however, was different. Hourly data from one of the combustion turbines at the plant show frequent dispatch downward and upward as well as a period in which the unit appeared not to operate at all (the reasons for this are unknown) as shown in Figure 8.

[36] For example, see slides 6 and 7 of https://www.in.gov/iurc/files/Stakeholder-presentation-CAC-Sommer-Final-version.pdf.

[37] We do not know if the summer and fall weeks are also representative of extreme weather events.

[38] Murphy, Sinnott, et. al. "Resource adequacy risks to the bulk power system in North America." Applied Energy. https://doi.org/10.1016/j.apenergy.2017.12.097 Received 29 June 2017; Received in revised form 7 December 2017; Accepted 27 December 2017

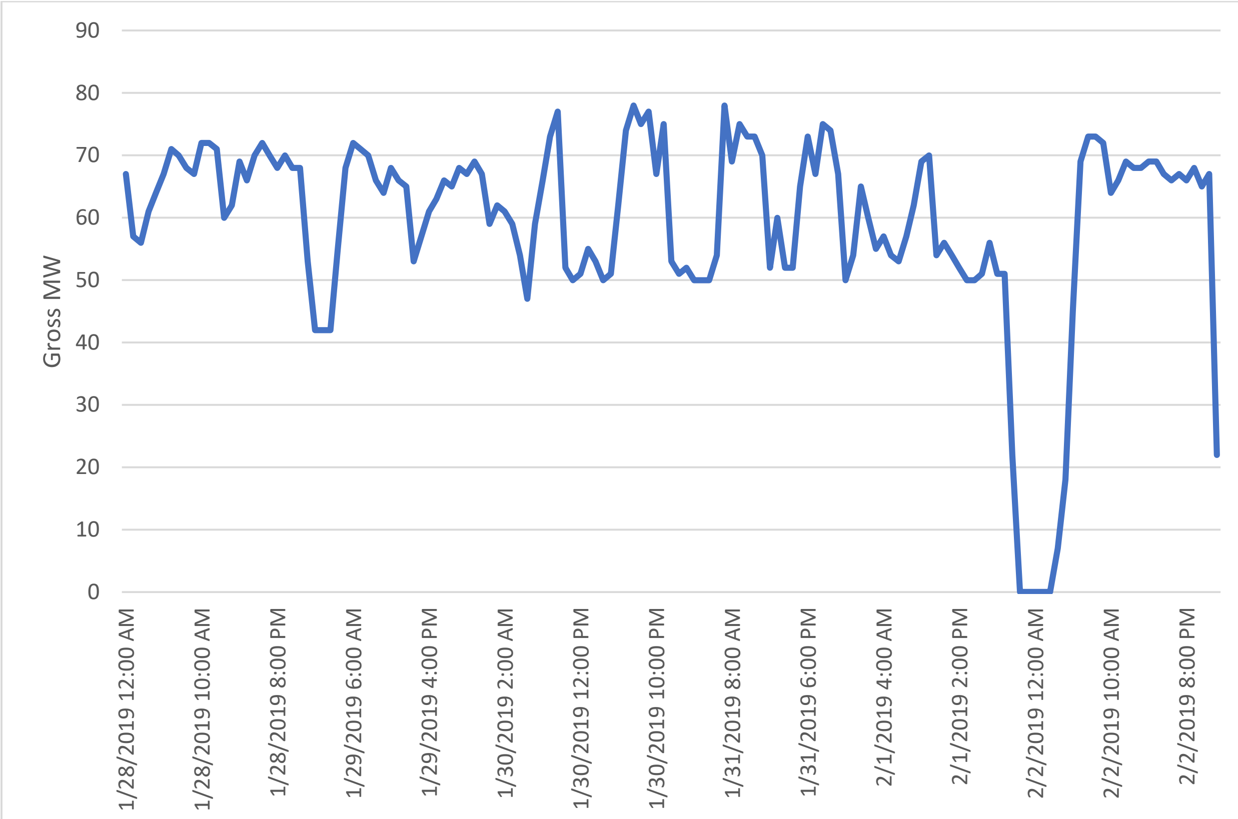


Figure 8. Gross Generation at Noblesville CC Unit 5 during PST Winter Period

The PST also appears to be overstating the performance of Duke's coal fleet. For example, during the period from 0:00 to 9:00 hours on February 2, 2019, the tool assumes that all of Duke's coal fleet is operating at full load or 4,748 MW. That period is shaded in grey in Figure 9, below.

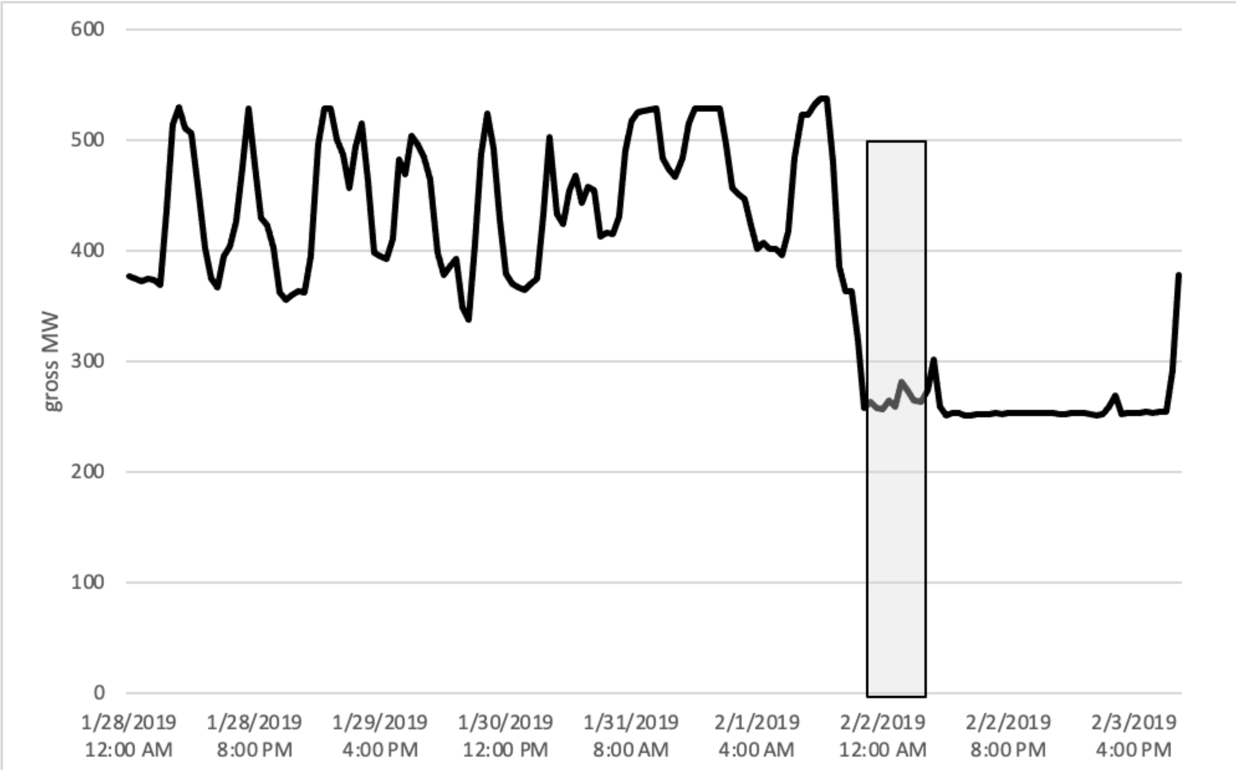


Figure 9. Cayuga Unit 1's Actual Gross Generation during PST Winter Period

Again, the reality was different. For example, Cayuga Unit 1, shown in Figure 9, was dispatched downward close to what appears to be its minimum loading level during this period. The reasons for this are unknown. This could be because it was economic to dispatch the unit downward, because of a partial derating of the unit, or for some other reason.

These concerns all add up to a tool that lacks credibility to accurately determine unserved energy and that simplifies away important dynamics of Duke's generator fleet and its interactions with the MISO system.

7.2.3 Environmental Sustainability Metric

It is also challenging to glean meaningful information from the Environmental and Sustainability metric based on how Duke set up the criteria. In regard to the question of, "Is the portfolio on track for meeting Duke Energy climate goals?", Duke's criteria is either yes or no; but Duke notes in the IRP that this is intended to compare "the average 2040 CO_2 emissions of each portfolio with a linear interpolation between the 2005 baseline and the 2050 Duke Energy Climate Goal of being net zero carbon emissions."[39] While Duke notes that this was added in response to a request from stakeholders, the metric needs more fleshing out to more than just a yes or no criteria. For example, how does the binary answer capture the benefit of one portfolio being on track to meet the Duke Energy Climate Goal faster than another portfolio?

[39] Duke Energy Indiana 2021 IRP, page 112.

Furthermore, the metric for the SO_2, NO_x, PM emissions and water usage was presented as a qualitative metric, based on a single year of 2030 for each portfolio. When evaluating emissions reductions or water usage, it would be preferable to see how the portfolio performs over time rather than being limited to a single year. In addition, Duke should compare actual numbers or percentage reductions for this kind of metric rather than merely using qualitative metrics.

Duke's method for scoring the qualitative metrics is based on the pie chart method, which include (i) executability, (ii) whether the portfolio mix can serve load under the extreme weather event in the PST, and (iii) SO_2, NOx, PM, and water emissions. Figure 10, below, provides a snapshot of the pie chart scoring that Duke used for the qualitative metric scoring criteria, which is challenging to compare. The presentation of the five ratings corresponding to how much of the pie chart is filled in is hard to translate for some of the categories. For example, how did Duke measure the executability criteria, which is based on the construction level through 2030? Duke indicates that higher levels of construction will drive this metric. It appears that the score for this criterion is driven by the number of renewable additions prior to 2030. It is not clear if this criterion is also taking into consideration the risk of building one very large generator such as the CC in Duke's Preferred Plan, which is a 1,200 MW addition in 2027.

○	◔	◑	◕	●
Poor	Fair	Good	Very Good	Excellent

Figure 10. Qualitative Metric Scoring[40]

[40] Duke Energy Indiana 2021 IRP, Table V.1, page 109.

8 Short Term Action Plan

Section 8 describes our assessment of Duke's performance in meeting the requirements of 170 IAC 4-7-9 of the Indiana IRP Rule. Please see Table 18 below for our findings.

Table 18. Summary of Duke's Achievement of Indiana IRP Rule at 170 IAC 4-7-9

IRP Rule	IRP Rule Description	Finding
4-7-9 (a)	A utility shall prepare a short term action plan as part of its IRP, and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	**Partial**
4-7-9 (b)	The short term action plan is a summary of the utility's preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9) of this rule	**Partial**
4-7-9 (c)	The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio and (B) The criteria for measuring progress toward the objective.	**Not Met**
4-7-9 (c)	(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	**Not Met**
4-7-9 (c)	(3) The implementation schedule for the preferred resource portfolio.	**Partial**
4-7-9 (c)	(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	**Not Met**
4-7-9 (c)	(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	**Not Met**

Duke's Short-Term Action Plan discussion in the IRP narrative is very short and lacks details about the resources for which it intends to seek certificates of public convenience and necessity ("CPCN"). Duke states that they will be issuing an RFP in early 2022, which will be facilitated by Charles River Associates ("CRA"). In this section, Duke states, "Duke Energy Indiana reasonably expects to select several generating projects to serve its customers that will be submitted to the Indiana Utility Regulatory Commission for its review and approval under the certificate of public convenience and necessity (CPCN) process."[41] In the Executive Summary of the IRP, Duke states, "The Company is committed to an RFP process for the near-term resource needs included in the Plan – i.e, solar and natural gas additions."[42] It appears that this reference to near term natural gas additions is to the 1,221 MW CC added in the Preferred Plan in 2027, which is the first year of the Preferred Plan in which a new gas resource is added. The other natural gas additions in the Preferred Plan are the combined heat and power added in 2028 and the CTs added in 2035. Since the filing of the IRP, Duke has released a Request for Proposals ("RFP"). It will be crucial that Duke allow stakeholders who have signed an NDA for the RFP process to be able to see the responses and the subsequent evaluation of bids.

[41] Duke Energy Indiana 2021 IRP, page 134.

[42] Duke Energy Indiana 2021 IRP, page 25.

The Short-Term Action Plan includes language that says, "The benefit of this Plan is the flexibility to adjust to changing market and regulatory conditions, as well as a smooth fleet transition to one that is more diverse and less carbon intensive."[43] It is confusing that this is the way in which Duke's Preferred Plan is described, since it is anchored around a large scale addition of a single CC resource in the amount of 1,221 MW. Not only is this a large addition of a single resource, but it also represents significant risks to Duke's ratepayers given the volatility of natural gas prices.

We recommend that Duke take the necessary steps to start planning for coal retirements and the new (non-thermal) generation to replace those units now. We disagree with Duke's conclusion in its Preferred Plan to delay the conversion of Edwardsport until 2035 and recommend Duke move toward that conversion immediately. There are significant fixed O&M and CAPEX savings for customers if Edwardsport is converted at an earlier date, and Duke's own optimized portfolios indicate that the model wanted to convert Edwardsport as soon as possible. Given the supply side constraints and inflationary pressures, it is imperative that Duke update its database to reflect the current realities of its electric system and influencing factors, which will entail changing inputs across several categories (i.e. power, fuel, and market price forecasts; all supply side resource costs; demand side resource costs) and not just apply increases in cost to new solar resources. We reiterate our request that Duke invite stakeholders to the table to work on reaching consensus on modeling disagreements well in advance of any resource filings.

[43] Duke Energy Indiana 2021 IRP, page 134.

PUBLIC ATTACHMENTS TO

Report on Duke Energy Indiana's 2021 IRP

CAC and EMCC Informal Discovery Request
Duke 2021 IRP
Data Request Set No. 1

FIFTH SUPPLEMENTAL RESPONSE 11/18/21
Supplemental Information is in Bold
CAC-EMCC Informal 1.1

Request:

Please provide the Encompass modeling files used for Duke Energy Indiana's 2021 IRP.

Response:

See Confidential Attachment CAC-EMCC Informal 1.1-A.

Supplemental Response:

See Confidential Attachment CAC-EMCC Informal 1.1-B.

Second Supplemental Response:

See Confidential Attachment CAC-EMCC Informal 1.1-C.

Third Supplemental Response:

See Duke Energy Indiana's response to Sierra Club 2.1.

Fourth Supplemental Response:

Please see Confidential Attachments CAC-EMCC Informal 1.1-D and 1.1-E respectively, for the DEI and MISO model input files related to the Deep Decarbonization Rapid Electrification portfolio. Pease note that the DEI and MISO base scenarios need to be imported first before importing the DDRE scenarios.

Fifth Supplemental Response:

Please see Confidential Attachment CAC-EMCC Informal 1.1-F for the revised MISO model input files (including sensitivities).

See Confidential Attachment CAC-EMCC Informal 1.1-G for the final DEI level model input files (optimized, hybrid, stakeholder, and sensitivities).

CAC
Duke 2021 IRP
Data Request Set No. 1
Received: November 16, 2020

CAC 1.3

Request:

Please provide, in spreadsheet format, Duke's most recent sales and peak demand forecast.

Response:

See Confidential Attachment CAC 1.3-A. Note that this is not the load forecast that will be used for Duke Energy Indiana's 2020 IRP.

CAC
Duke 2021 IRP
Data Request Set No. 3
Received: November 16, 2021

CAC 3.1

Request:

Please provide the post process data for production cost runs.

Response:

See Confidential Attachment CAC 3.1-A.

CAC
IURC Cause No. 45654
Data Request Set No. 6
Received: February 10, 2022

CAC 6.6

Request:

Please refer to the peak demand and energy usage forecast provided on page 154 of the 2021 IRP.

a. Please explain if the increase in peak demand between 2022 and 2023 is due to the addition of new wholesale customers. If it is not, please explain what is driving the projected increase in demand.
b. Please confirm if the decrease in wholesale annual MW between 2025 and 2028 is due to confirmed losses of customers.

Response:

a. New wholesale contracts are a primary driver to the increase in the peak demand between 2022 and 2023.
b. The decrease in wholesale annual MW between 2025 and 2028 is due to the termination of existing wholesale contracts.

CAC
IURC Cause No. 45654
Data Request Set No. 6
Received: February 10, 2022

CAC 6.7

Request:

Please refer to page 38 of the 2021 IRP where it says "In addition to declining prices, solar costs include an investment tax credit extension through 2025, and assume a tax equity partner which provides for more efficient financing."

a. Please provide the supporting workbooks for the development of solar costs that include a tax equity partnership for the Investment Tax Credit.
b. Please refer to the workbook named "Confidential Attachment SC 4.1-B". Please explain if the costs for new solar resources contained in this workbook assume normalization of the ITC or if they assume a tax equity partnership is used.

Response:

a. In order to reflect the benefits of a tax-equity partnership, the fixed charge rate for solar was reduced the tax-equity discounts by the amounts below:

ITC Period	Factor	Tax Equity Discount
2021-2024	0.8897	11.03%
2025	0.9113	8.87%
2026+	0.9728	2.72%

b. Confidential Attachment SC 4.1-B assumes normalization of the ITC.

CAC
IURC Cause No. 45654
Data Request Set No. 6
Received: February 10, 2022

CAC 6.12

Request:

Please provide the supporting workbooks, with all formulas and links intact, used to develop the avoided cost for energy efficiency screening.

Response:

Please see Confidential Attachment CAC 6.12-A.

CAC
IURC Cause No. 45654
Data Request Set No. 6
Received: February 10, 2022

CAC 6.18

Request:

Please provide the workbook, with all formulas and links intact, used to develop the levelized costs for new energy efficiency resources.

Response:

Please see Confidential Attachments CAC 6.18 A-F:

- Confidential Attachment CAC 6.18-A: Avoided T&D value of bundles
- Confidential Attachment CAC 6.18-B: Measure Summary & Levelized Costs - 2021-2023
- Confidential Attachment CAC 6.18-C: Measure Summary & Levelized Costs - 2024-2026
- Confidential Attachment CAC 6.18-D: Measure Summary & Levelized Costs - 2027-2034
- Confidential Attachment CAC 6.18-E: Measure Summary & Levelized Costs - 2035-2042
- Confidential Attachment CAC 6.18-F: Measure Summary & Levelized Costs - 2043-2050

CAC
IURC Cause No. 45654
Data Request Set No. 7
Received: March 25, 2022

SUPPLEMENTAL RESPONSE 4-26-22
SUPPLEMENTAL INFORMATION IN BOLD
CAC 7.1

Request:

Please refer to the workbooks provided as confidential attachments for the response to CAC 3.1A.

a. Please provide the version of these workbooks that show the calculation for the FOM and the Ongoing Capex with all formulas and links intact.
b. Please explain what is included in the FOM expense and why there are ongoing FOM expenses for the coal units that retire before the end of the planning period (for example Gallagher 2 and Gallagher 4, Gibson 4, and Gibson 5).

Objection:

Duke Energy Indiana objects to this request as vague and ambiguous, particularly the portion of the request seeking "the version of these workbooks that show the calculation . . . ." Duke Energy Indiana has previously provided the actual inputs to the 2021 IRP modeling and objects to providing information not used in the 2021 IRP as overly broad and not reasonably calculated to lead to admissible evidence in this proceeding.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. See objection.
b. The FOM expense includes all of the budget O&M costs not modeled in the variable O&M rate (VOM), including direct labor; non-outage maintenance materials and contracts; outage labor materials and contracts not included in VOM, if any; waste disposal costs; allocations; property taxes; insurance; and any future incremental environmental O&M costs that may be modeled. Also, the FOM expense includes planned outage "netted variable O&M" that realigns in time the planned outage O&M costs calculated by Encompass on an annual levelized basis that are represented in the VOM rate.

   The FOM expense that appears ongoing after retirement is continuing property tax expense. First, property taxes are paid in arrears, so the full property tax amount appears in the year after retirement, for the prior tax year. After that, property taxes are modeled with a 95% reduction in cost. To the extent that the land continues to be owned and some structures remain used and useful after retirement (typically at least the substation/switchyard), some property tax expense continues for the site even after retirement of all generators.

In addition, the overall cost streams also include future incremental landfill post-closure costs, if any, that are not already sunk. However, instead of showing these cash flows post-retirement, the costs are present-valued and levelized over the operating life of the unit.

Supplemental Response 4-26-22:

Subject to and without waiving or limiting its objections and after communication with counsel for CAC who indicated that CAC is seeking additional information regarding outage assumptions and "how the FOM was compiled," Duke Energy Indiana is providing the following supplemental response:

The FOM assumed in the 2021 IRP and which was previously provided to CAC is developed through a process designed to provide "dynamic fixed cost" characterizations for existing units, for retirement analysis purposes. This process uses the actual total O&M budgets for the existing units to establish the baseline fixed operations and maintenance costs ("FOM") portion of the total, net of defined variable O&M costs that are otherwise calculated by Encompass via the variable O&M rates. Routine maintenance capital costs, ongoing environmental capital costs (SCR catalyst, landfill), and projected environmental capital costs (316(b), ELG, etc.) are included as applicable. The FOM and capital costs are considered "dynamic" because they vary with how the units are forecasted to be dispatched. For example, if a unit operates with a high capacity factor, it will require maintenance (capital and O&M) more frequently and the calculation would depict that with a representation of more frequent outage/maintenance expenses. Conversely, if a unit operates with a low capacity factor, then outage/maintenance expenses would appear less frequently. Thus, there is not one single set of forecasted data – the costs are dynamic and specific to each individual Encompass run that may produce different levels of operation on the units.

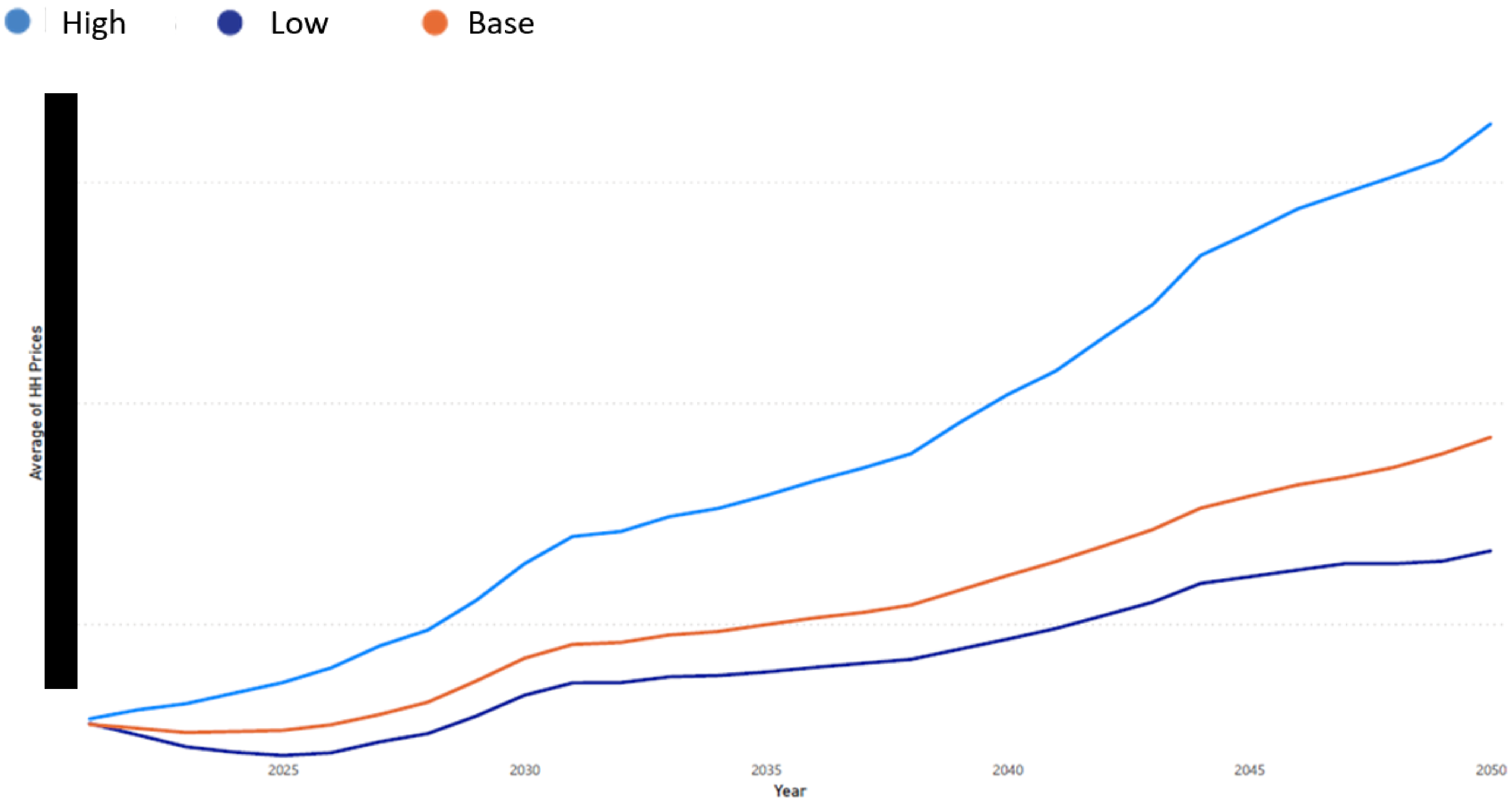
Regarding the outage rates assumed in the 2021 IRP:

- **For energy, the Company uses a 5-year average equivalent unplanned outage rate (EUOR) that accounts for forced derates, forced outages, and maintenance outages.**
- **For capacity, the Company starts with the most recent actual 3-year rolling average XEFORd as actually used by MISO to calculate UCAP. The Company then projects forward the XEFORd from the most recent 3-year rolling average into a longer-term 5-year rolling average. The XEFORd is then used along with the ICAP to calculate the UCAP. This is first IRP which has been modeled in UCAP, so this is the first time Duke Energy Indiana has implemented these types of calculations in modeling space.**

Please see Confidential Attachment CAC 7.1-A for additional explanation of the process used to develop the baseline FOM used in the 2021 IRP.

Gas Forecasts

DEI IRP Slide 13 from 06/21/21 Meeting



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