Report on Duke Energy Indiana's 2018 IRP

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Overview

The following comments on the 2018 Integrated Resource Plan ("IRP") submitted by Duke Energy Indiana ("Duke" or the "Company") were prepared by Anna Sommer, Chelsea Hotaling, and Chris Neme of Energy Futures Group, and Elizabeth A. Stanton, PhD, of the Applied Economics Clinic. These comments were prepared for Citizens Action Coalition of Indiana ("CAC") 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 2018 IRP is organized in response to guidance on IRP preparation in the IURC's IRP Rule. Table 1 illustrates the Indiana IRP rule sections and provides the section in which those requirements will be addressed in detail. Our review of Duke's 2018 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- Duke applies its reserve margin requirement to all months of the year rather than just the MISO coincident peak (Section 3.1);
- Duke requires the model to self-supply capacity in all months of the year rather than purchasing from other utilities (Section 3.2);
- Duke tries to solve the problem of unrealistic market purchases by imposing a hurdle rate on purchases, but this is a band-aid on the problem and an imperfect one at that (Section 3.2);
- Coal unit retirements are unnecessarily limited to 2024 or later and only to Duke's existing pulverized coal units (Section 5.2);
- Duke's energy efficiency bundles are unreasonably high in cost and suffer from other flaws that prevent the selection of the optimal portfolio of energy efficiency measures (Section 3.5);
- Capital costs for renewables are higher than is justifiable (Section 5.1);
- Capital costs for combined cycles are lower than is justifiable (Section 5.1);
- Wind and battery storage is limited to 250 MW per year without basis (Section 3.4);
- A $5/MWh adder for new solar resources is based on a study for Duke's Carolina service territory that has no relevance to Indiana and was rejected by the North Carolina Utilities Commission (Section 3.4);
- Duke refused to provide copies of the System Optimizer and Planning and Risk model manuals except in person despite having done so in its prior IRP (Section 1);
- Duke did not deliver the modeling files required for the Technical Appendix in Indiana's IRP rule (Section 1); and
- Duke's pre-IRP stakeholder process was frustrating in a number of respects including the tendency of Duke to push stakeholder recommendations off to the next IRP filing (Section 2.1).

We expressly reserve the right to supplement and revise these comments in substance and to add additional sponsors to these comments or future iterations of comments. Further, due to extensive data delays related to Duke providing any justification and underlying analyses related to its basis for limiting coal plant retirements to 2024 and beyond in its IRP, these comments may be supplemented with further analysis on this issue in particular.

Table 1. Summary of Duke's Compliance with of Indiana's IRP Rules

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

Duke's technical appendix was significantly incomplete at the time of the IRP filing. CAC had to request the System Optimizer ("SO") capacity expansion model files and the Planning and Risk ("PaR") production cost model files from Duke through discovery. When Duke responded to our request for the modeling files, it initially just provided CAC with the modeling input and output files for its preferred portfolio – the so-called Moderate Transition portfolio. As a result, CAC had to follow up with Duke to obtain the modeling input and output files for the other portfolios Duke modeled in the 2018 IRP. This process of having to request the modeling files and then following up with Duke delayed our review of the modeling files.

During the pre-IRP submission phase, Duke provided stakeholders with a workbook titled "Data Summary for Stakeholders". This workbook included the model inputs for load, commodity prices, CO_2 price forecast, energy efficiency costs, resource unit characteristics, capital cost forecasts, and renewable production forecasts. However, this workbook was not part of Duke's IRP filing and, since it was originally provided in December of 2018, we do not know how much of the information changed, if any, between then and the July 1, 2019 IRP filing date.[1]

CAC also had to request the Excel workbooks Duke uses to combine capital costs from System Optimizer with production costs from Planning and Risk into the total Net Present Value ("NPV") calculation despite the fact that Indiana's IRP rule explicitly requires that this information be provided as part of the technical appendix.

[1] The exception to this being an update to solar costs provided to stakeholders as "Solar Cost Update 01.18.2019".

Finally, CAC asked Duke for copies of the System Optimizer and Planning and Risk model manuals in Informal CAC Data Request 11.2, but Duke objected to this request. In response to Informal CAC Data Request 11.2, Duke stated, "Duke Energy Indiana objects to this request to the extent it seeks documents that contain copyrighted, proprietary information belonging to third parties. Duke Energy Indiana will make the information available for on-site review at its Plainfield, Indiana offices upon reasonable notice and advanced arrangements made with Duke Energy Indiana's counsel." This was despite the fact that Duke had previously provided these documents to CAC as part of the 2015 IRP process.[2] We often find the model manual to be helpful in, if not critical to, understanding the model files and troubleshooting modeling problems. In addition, the model manual may provide insight into the different inputs and settings for the model, the constraints that can be imposed on the model, etc. - all of which can impact the model results.

[2]Informal CAC Data Request 2.11 in the Duke 2015 IRP process.

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 regarding the public advisory process. Please see Table 3 below for our findings.

Table 3. Summary of Duke's Achievement of Indiana IRP Rule 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.	Not Met
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.	Partial
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	Not Met
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 PRE-IRP STAKEHOLDER PROCESS

Throughout the IRP stakeholder process and the stakeholder portfolio exercise, CAC provided numerous suggestions on modeling improvements that Duke either did not agree with or said it would consider in its next IRP. Some of the suggestions made by CAC and its consultants included modeling on a UCAP rather than an ICAP basis, removing the monthly reserve margin constraint, lowering the capital costs of solar and wind resources, not applying a market hurdle rate to limit market purchases, and modeling energy efficiency ("EE") in a decrement approach. We believe most of these would have a material impact on Duke's results.

We have heard it suggested that there is no issue with deferring these issues to the next IRP three years down the road because Duke has no capacity needs. This is a circular argument that misses the point of an IRP exercise. IRPs are not intended to merely examine the steps a utility ought to take to fill an anticipated need but are also an examination of whether existing resources are economic to operate or should come offline early. The lack of any near-term retirement analysis and the stasis in its resource portfolio happens precisely because it chose to so drastically narrow the resource choices in the next five years that the model would be unlikely to make changes to Duke's existing portfolio. Deferring addressing the many modeling issues we raised during the stakeholder process to the next IRP is not prudent resource planning because it fails to address the many critical issues in this IRP.

We attempted to rectify a number of these modeling issues by engaging in a process with Duke to model alternative scenarios and portfolios. Duke deserves credit for taking the time to engage with us and the Energy Matters Community Coalition and its consultant in this effort. However, the process ended without success because there was not enough time to troubleshoot the problem of System Optimizer returning unrealistic results. The upshot of this effort is that it gave us an opportunity to more deeply understand Duke's modeling and modeling errors before the IRP was filed.

Mr. Park takes umbrage at these criticisms of the stakeholder process saying that Duke held "six, day-long stakeholder meetings…in addition to numerous conference calls and discovery responses."[3] As in most instances, quantity does not, however, equal quality. Karl Rábago of the Pace Energy and Climate Center describes the problems with utility stakeholder processes well:

> *Badly done, such workshops can be "time and resource intensive, which privileges the utilities, and invites gaming, such as legislative end-runs," Rabago, a former Texas utility commissioner, added. Such workshops can sometimes be "vague and unfocused" and such processes can be "a cover for hidden staff agendas" if the guiding vision is inadequate…*[4]

And though the following quote from Mr. Rábago originally referred to a Commission-directed stakeholder process in another state, we think it applies equally well to the process Duke engaged in here. Duke can do a stakeholder process

> *"…just to say it had a collaborative stakeholder process with working groups," he said. "If it is only a cover for doing what it wants to do, or for doing nothing, then it's worse than doing nothing because it wastes resources, creates unfulfilled expectations and erodes stakeholders' confidence in regulation."*[5]

[3] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 13, lines 6-7.
[4] Trabish, Herman K. "A utility regulatory process for the 21st century gets a test run in Hawaii." March 19, 2019. Retrieved from: https://www.utilitydive.com/news/a-utility-regulatory-process-for-the-21st-century-gets-a-test-run-in-hawaii/550146/
[5] *Id.*

2.2 POST-IRP FILING PROCESS

In its IRP, Duke describes 10MW of battery storage in 2019 and 5MW in 2020 as a resource decision it "had committed prior to the completion of this IRP analysis and are included in all portfolios."[6] In Duke's final stakeholder meeting held on June 20, 2019, just 11 days before the IRP was filed, the presentation slides gave no indication that battery storage was included in its optimized and alternative portfolios developed. On slide 12 of the presentation,[7] Duke provided stakeholders with a table highlighting the retirements and cumulative additions of resources under its preferred portfolio, but there was nothing listed for battery storage additions for 2019 and 2020 either. Resource decisions, regardless of whether they are "committed" or not, need to be justified in some way, and Duke cannot credibly argue that the IRP does that. The inclusion of these resources has the potential effect of dampening the model's preference for demand-side management ("DSM") which is important given the direct linkage between the IRP and the level of DSM Duke is likely to implement in its next three-year filing. We had no opportunity to address this issue during the stakeholder process because, again, it did not come up until after Duke's IRP was filed.

When responding to CAC's discovery requests, Duke usually took at least 15 business days or longer to respond. On numerous occasions, CAC had to reach out to Duke for an update on when discovery responses would be received. As mentioned in Section 1, there was a delay in getting the modeling input and output files from Duke. When CAC communicated with Duke that further conversations were needed to get clarification, Duke was willing to engage with CAC for those meetings and did provide information requested during those phone calls. Nonetheless, Duke's presentation of data throughout the post-IRP filing process was often delayed, frustrating the goals of this IRP stakeholder process.

2.3 CHOOSING A REPLACEMENT FOR SYSTEM OPTIMIZER

Nearly every IRP filed with state-level utility commissions is underpinned by some form of electric planning modeling. For decades the model of choice for many utilities has been Strategist and secondarily System Optimizer, but the vendor of both, ABB, will soon cease to support both software packages. We understand that Duke is in the process of choosing a new model itself. We have verbally made suggestions to Duke about models that it should consider and that it include key parties in the evaluation of a new planning model given how consequential the model choice is for regulatory purposes. This section describes in more detail one of the key recommendations we have made to Duke in conversation about this topic.

Significant time and resources are embedded in the selection of a planning model, which makes it very unlikely that a utility will switch to another platform once it has adopted a particular software. Because of this and in recognition of the fact that Commissions and intervenors also have a lot at stake in planning model selection, the Minnesota utilities[8] engaged in a joint Request for Information ("RFI") process with Commission staff in that state, the consumer advocate, and environmental intervenors. The purpose of the RFI process was to jointly evaluate alternatives to Strategist and System Optimizer

[6] Duke Energy Indiana 2018 IRP, p. 60.

[7] Duke Energy Indiana Stakeholder Workshop #6 held on June 20, 2019. Powerpoint slides retrieved from https://www.duke-energy.com/_/media/pdfs/for-your-home/indiana-irp/dei-irp-meeting-6.pdf?la=en

[8] Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy.

and vet those alternatives as a group. The ultimate selection of the final software package was up to each utility.

The initial RFI request was sent to all potential model vendors identified by the RFI participants including intervenors. After initial receipt of proposals, the group gathered together to evaluate the responses and whittle the list down to 4 final candidates to come for in-depth presentations and Q&A sessions with the RFI parties. Each utility performed its own additional due diligence including testing out the top two software packages before selecting the software that made the most sense for each.

This process was beneficial to all parties for a number of reasons:

1. The parties used their collective knowledge to judge a wide range of software packages. Models are complex and understanding them takes time. The diversity of parties meant that there were often one or more parties who had prior experience with the models in question.
2. The parties brought a range of questions and concerns to the table. This particularly strengthened the quality of the Q&A sessions with each vendor because the questions came from multiple perspectives and experiences.
3. The process instilled confidence in the model ultimately selected by each utility. The opportunity to vet and learn about the models evaluated helped avoid any pitfalls about whether the model each utility chose would be appropriate for integrated resource planning and for use in Minnesota.
4. The process created a unique opportunity for parties to discuss common modeling pitfalls, goals, and pros and cons. It was a rare instance in which collaboration rather than litigation was the only purpose, and it fostered frank dialogue between the parties.

An inclusive RFI process enables the utility to consider a broad universe of potential software choices, has the potential to educate stakeholders on the complex topic of modeling, and can help instill confidence that the new model will be capable of simulating the resource choices available to the utility and provide transparency while doing so. We would strongly encourage Duke to employ this process in selecting its replacement for System Optimizer.

3 Integrated Resource Plan Contents

Section 3 focuses on how Duke performed regarding meeting the requirement of 170 IAC 4-7-4 of the Indiana IRP Rule regarding the contents of the IRP. Please see **Table 4** below for our findings.

Table 4. Summary of Duke's Achievement of Indiana IRP Rule 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.	Met
4-7-4 (4)	A description of the utility's existing resources in compliance with section 6(a) of this rule.	Partial
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	Met
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.	Partial
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.	Mostly
4-7-4 (9)	(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Not Met
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.	Not Met
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.	Partial
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.	Not Met
4-7-4 (17)	A discussion of the designated contemporary issues designated, if required by section 2.7(e).	NA
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	Not Met

4-7-4 (19)	For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	**Partial**
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.	**Partial**
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.	**Partial**
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.	**Not Met**
4-7-4 (25)	A description and analysis of the utility's base case scenario, sometimes referred to as 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.	**Not Met**
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.	**Partial**
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.	**Partial**

3.1 MODELED MINIMUM RESERVE MARGIN REQUIREMENT

Duke modeled a reserve margin requirement of 15% on an ICAP basis[9] applied to the peak load *in every month of every year* in the planning period. As discussed in Section 2.2 of MISO's Resource Adequacy Business Practice Manual,[10] MISO rules require market participants to demonstrate their ability to meet their resource adequacy requirements on a UCAP, not an ICAP, basis. Setting this issue aside, MISO requires each Market Participant ("MP") to demonstrate its ability to meet its Planning Reserve Margin Requirement ("PRMR"), defined as its coincident peak demand forecast adjusted for purchases, sales, and transmission losses and MISO's Planning Reserve Margin ("PRM"). There is no reserve margin requirement imposed at times outside of MISO's coincident peak.

In conversations with Duke, it has been suggested that applying the PRM to all months is appropriate because MISO will move to a seasonal resource adequacy construct at some time in the future. The movement to a seasonal RA construct by no means is a foregone conclusion. A seasonal construct is one of several steps MISO may take to address MaxGen events.[11] The most recently available MISO presentation on this topic says that stakeholders have told MISO that "MISO's current analysis [is] unconvincing as a basis for pursuing a seasonal resource adequacy construct" and MISO responded that its "analysis to date, coupled with historical events, has been intended to provide evidence that <u>exploring</u> a seasonal construct is warranted. MISO will continue to work with stakeholders on analysis to support any future changes." [12]

In his rebuttal testimony in IURC Cause No. 45253, Duke's Director of IRP & Analytics - Midwest, Scott Park, contends that we are "confus[ing] the short-term resource adequacy view of MISO with the long-term resource adequacy that needs to be considered in the IRP."[13] There is no confusion. MISO very much views itself as ensuring long-term resource adequacy as demonstrated by several references to that term throughout Business Practice Manual ("BPM") No. 11, the rules that govern resource adequacy in MISO. For example, BPM No. 11 states, "MISO will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning."[14] A far more appropriate assumption would have been to assume the nine-year trajectory of reserve margin requirements laid out in MISO's 2020 Loss of Load Expectation Study.[15]

As we told Duke during the stakeholder process, we see no issue with modeling a monthly reserve margin requirement as a sensitivity, though it may not be the case that the same requirement applies in all seasons. However, it is not just inappropriate, but fundamentally flawed to do so as a base assumption in all runs. Indeed, IRP Rule 170 IAC 4-7-4 (25)(D) provides three conditions for when the

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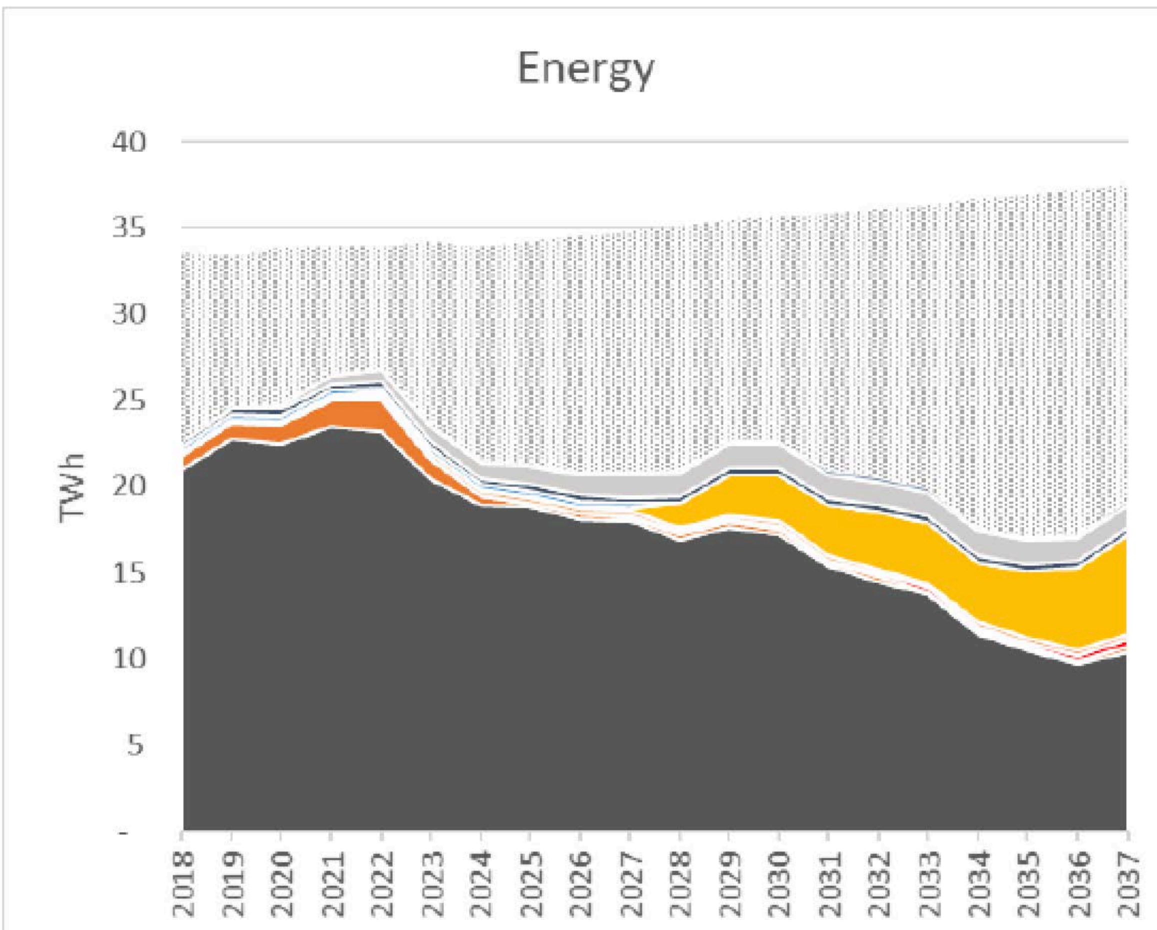
[9] Duke Energy Indiana 2018 IRP, p. 30.
[10] MISO Resource Adequacy Business Practice Manual, BPM-011-r22. Effective date October 1, 2019. Retrieved from https://www.misoenergy.org/legal/business-practice-manuals/
[11] Maximum Generation events occur when the economic supply of energy is not sufficient to meet fixed demand.
[12] See PDF page 8 of https://cdn.misoenergy.org/20190807%20RASC%20Item%2004b%20RAN%20Phase%203%20(RASC010)369675.pdf
[13] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 4, lines 11 – 12.
[14] MISO Resource Adequacy Business Practice Manual, BPM-011-r22. Effective date October 1, 2019. Retrieved from https://www.misoenergy.org/legal/business-practice-manuals/
[15] See here: https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf

utility can include future resources, laws, or policies in its base case scenario. These three conditions include:

> (i) a utility subject to section 2.6 of the IRP 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 seasonal RA construct clearly does not meet any of these three criteria. ***We view this assumption as a fatal flaw in Duke's modeling.*** Throughout its runs presented during the stakeholder workshops, there was a pattern of retaining generators and buying enormous quantities of energy out of the MISO market. This is shown, for example, in Duke's Reference Case with a Carbon Tax presented at its December 18, 2018 workshop and replicated here as Figure 1.

Figure 1. Sources of Energy in Preliminary Duke Reference Case Run[16]



[16] See slide 26 of Duke's December 18, 2018 presentation.

It is nonsensical and unlikely that Duke should buy huge amounts of generation from MISO while self-supplying excess capacity. That Duke did not even explore changing its PRMR assumption is a critical misstep and completely undermines its IRP modeling results since the load forecast and its applicable reserve margin requirement are among the single most important inputs into an IRP model.[17]

In response to the prior version of these comments, Mr. Park invents the idea that our report "goes on to discuss the situation where enough solar has been added and dispatchable generation retired that the reserve margin is at its lowest on a high load morning in winter."[18] These comments do not say anything of that nature -- this is a scenario Mr. Park imagined on several occasions during stakeholder workshops and calls with Duke that has no basis in reality. It implies a lack of generation which presumes that MISO has abdicated its responsibility to ensure there is sufficient generation available to meet load.

Mr. Park further contrives the idea that the prior version of our report "says that serving a winter peak should not be an important consideration of the IRP and that the utility can rely on MISO to serve that peak. What the report fails to consider is that if the economics of the industry drive more coal retirements and solar additions, the rest of MISO will also become winter peaking for planning purposes which means that the winter peak now becomes the primary reserve margin constraint."[19] Again, we say no such thing. Taking these points in reverse, a system is only winter peaking if load becomes highest in the winter, that has nothing to do with the generation serving that load, on that point Mr. Park is simply confused. On the first point, serving load throughout the year is clearly important, we have never said it was not. Mr. Park seems to be peddling a fiction that at some point in the future most, perhaps even all, generation in MISO would be solar based and therefore the system will become subject to outage. It is nonsense to think that MISO, its participating utilities, state utility commissions, the environmental sector, consumer advocates, etc., will be indifferent to the reliability of electricity even as the source of supply changes. Indeed, the environmental sector submitted the following to MISO:

> *The Environmental/Other Sector appreciates MISO's continued investigation of the occurrence of reliability risk outside of summer months as part of its consideration of a seasonal resource adequacy construct. We urge MISO to continue to dig deeper into the details, conduct more temporally granular analysis, and consider how the analysis and subsequent construct development process can be shaped by assumptions on the future make up on the region's generation mix. We ask that MISO continue to iterate its analysis to include additional sensitivities as this process moves forward.*
>
> *In addition to seasonal forced outage rates, monthly generators output data, and LMR availability and expected performance assumptions, a reasonable and useful analysis on the occurrence of LOLE risk throughout the year should include sensitivities that*

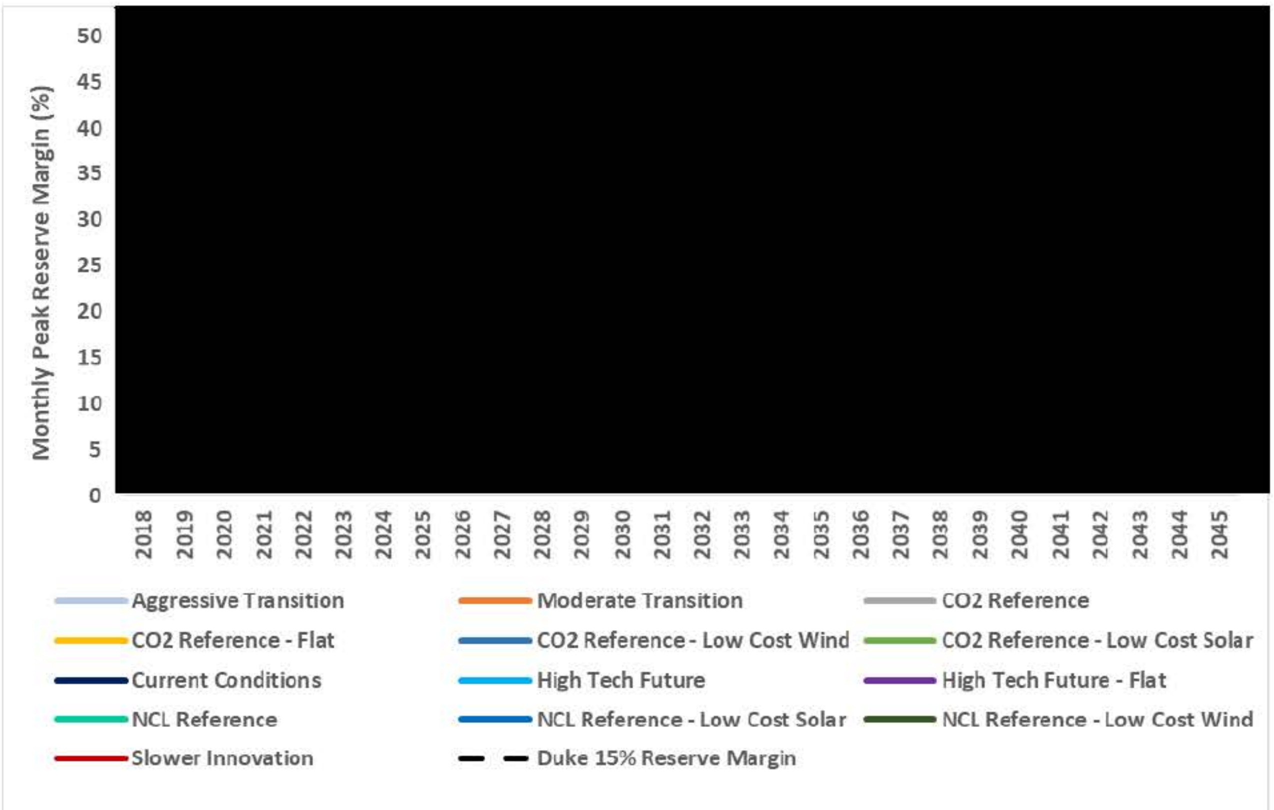
[17] Our conversations with Duke led us to believe that it would not change this assumption even for the runs specified by stakeholders.
[18] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 4, line 18 to page 5, line 1.
[19] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 5, lines 2 – 7.

> *assume the generation mix in MISO relies more heavily on variable renewable energy resources.*[20]

Mr. Park has invented a scenario that will not happen and that is seemingly intended to implicate variable renewables as unreliable without any evidence to back that claim up.

Confidential Figure 2 below shows the peak month reserve margin in each of Duke's portfolios.[21]

Confidential Figure 2. Comparison of Peak Month Reserve Margin for Modeled Portfolios [22]



The effect of retaining a 15% or greater reserve margin in all months is that many of these portfolios are dramatically overbuilt in most years of the planning period. The levels of excess capacity in these portfolios can hardly be expected to be economic, and we think they arise from the flawed assumption that the reserve margin requirement of 15% holds throughout the year and that Duke must self-supply all its own capacity as described in the following section.

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[20] Posted by Sam Gomberg, Union of Concerned Scientists on July 25, 2019. Retrieved from: https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/rasc-ran-phase-3-capacity-accreditation-rasc010-20190710/

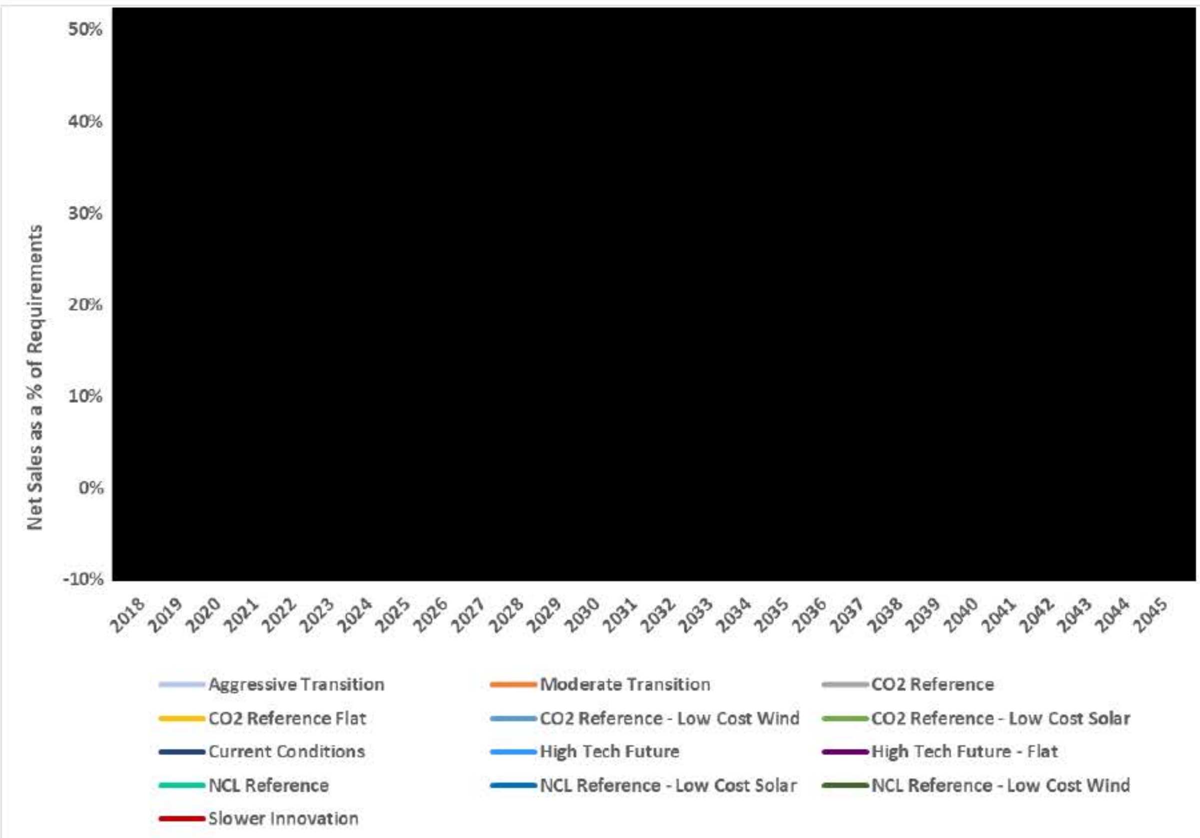
[21] For reasons that are unclear, Duke modeled two runs out to 2045 – the so-called Aggressive Transition and Moderate Transition scenarios.

[22] All but two scenarios, Moderate Transition and Aggressive Transition, were simulated through 2038. Duke does not say why it modeled these two portfolios through 2045.

3.2 MARKET PURCHASES AND SALES OF CAPACITY AND ENERGY

Despite these very high reserve margins, the scenarios typically include significant purchases of off-system energy as shown in Confidential Figure 3. A positive percentage indicates more sales than purchases, while a negative value indicates the reverse.

***Confidential* Figure 3. Net Purchases as a Percentage of Requirements**



Mr. Park argues that the Moderate Transition plan "has relatively low market purchases over the next 10 years"[23] and that we "confuse reserve margins and its relation to market purchases."[24] First, we would not construe purchasing roughly a [redacted] of total energy from the market as "low". And there is no confusing reserve margin and market purchases. Our point is that where a utility assumes that it needs to obtain sufficient capacity to meet excessive reserve margins, one would expect high levels of sales, not purchases of energy. And while the reverse might be true temporarily, it is imprudent to plan one's system to *maintain* that practice for years to come. At its core, the implication is that all that excess capacity should be staffed and maintained at customer cost but a significant share of energy will not come from Duke generators, but rather from other, off-system power plants. Such a costly strategy is plainly not in the economic interest of the customers who would be paying for it.

[23] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 5, lines 2 – 7.

[24] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 6, lines 12 – 13.

To at least partially address the high level of market purchases discussed during the stakeholder workshops, Duke placed a $2/MWh hurdle rate on market purchases. In the IRP, Duke stated:

> *To better calibrate the way in which dispatch model replicates making real-world generation unit commitment decisions, the IRP dispatch model is not permitted to purchase energy from the market unless the wholesale power price forecast is at least $2/MWh greater than the forecasted marginal cost of energy from company owned-resources.*[25]

The hurdle rate is intended to address the symptom – unrealistic market purchases – but not the cause of those purchases. We would rather see Duke test its modeling, for example by relaxing the reserve margin constraint, in an attempt to isolate the cause of the problem. Arriving at realistic results is key to instilling confidence in the IRP as a whole. As it stands now, we do not have confidence that Duke's running of System Optimizer can return a realistic result. And indeed, Figure 2 still reflects the same problem – net purchases well in excess of 20% – in many portfolios despite the inclusion of the $2 per MWh hurdle rate. Indeed, the Moderate Transition portfolio, Duke's preferred plan, *does not fall below 20% net purchases until* [redacted].

While market purchases of *energy* were modeled, Duke did not model short-term capacity purchases at all. In response to Informal CAC Data Request 7.9, Duke said, "We consider any CT selected for reserve margin requirements as one that could be replaced by a bilateral purchase contract at the same cost as a constructed CT." A combustion turbine ("CT") is not a reasonable proxy for a market purchase. There is a significant difference in the life of a CT versus the short-term duration of a capacity purchase. While a single year's levelized price of a CT might serve as a proxy for a capacity purchase, there is no comparison between a CT, modeled with a book life of 35 years, and a one-year capacity purchase. There is no way to construe CTs as a reasonable proxy for a short-term capacity purchase.

3.3 MODELING ON AN ICAP VERSUS UCAP BASIS

MISO carries out its responsibility for ensuring there are enough resources to serve load amongst its load serving entities ("LSEs"), including Duke Energy Indiana, in part by conducting yearly loss of load expectation ("LOLE") studies to determine the appropriate planning reserve margin requirement ("PRMR"). The PRMR is intended to ensure that the MISO system meets a 1 day in 10 years lost load standard. The PRMR is defined on a UCAP basis and secondarily on an ICAP basis.[26] LSEs must then annually demonstrate their ability to meet their coincident peak load plus MISO's PRMR on a UCAP basis.

However, Duke models its system on an ICAP basis using the nameplate MW for its generators. Joint Commenters expressed concern about using an ICAP convention in Duke's 2015 IRP and strongly recommended that Duke change its modeling to use UCAP so that its modeling results are consistent with the manner in which MISO judges DEI's ability to meet resource adequacy requirements. Modeling its units on a UCAP basis explicitly accounts for the reliability of those units and allows System Optimizer to more highly value those units that provide greater levels of reliability than units of a similar size and

[25] Duke Energy Indiana 2018 IRP, p. 25.
[26] The ICAP requirement is based on the installed capacity of a power plant, while the UCAP requirement considers a unit's forced outage rate. As a result, a plant's UCAP value is generally lower than its ICAP value.

type. There is no "difficulty" here, this is standard practice amongst utilities in MISO and yet Duke has again refused to move to this standard convention.

3.4 LIMITATIONS AND FLAWS IN RESOURCE SELECTION

We strongly suspect that holding the 15% PRMR constant throughout the year distorted resource optimization within System Optimizer. If that issue were corrected, however, there are other modeling flaws that would likely impact the modeling results. With respect to renewables, Duke placed several restrictions on the modeling of new renewable resources including:

- Inappropriately adding a $5/MWh variable O&M charge to solar additions above 800MW of nameplate capacity based on a study conducted for the Company's Carolinas service territory rather than Indiana;
- Modeling solar resources with a 50% capacity contribution for the months of [redacted] and a 0% capacity contribution in the months of [redacted] contrary to MISO rules;
- Placing an arbitrary 250 MW per year constraint, each, on the amount of wind and batteries that can be selected by the model in any given year;[27] and
- Modeling indefensibly high solar and wind capital costs as discussed in Section 5 of this report.

If the level of solar in any given portfolio exceeds 800 MW, Duke adds a $5/MWh variable O&M charge to every MWh of solar energy produced. The adder increases by $5/MWh for every additional 800 MW tranche of solar. Duke attempts to justify this adder by saying that it "reflects our estimate of the additional cost of operating the system with a high penetration of solar resource."[28] In response to Informal CAC Data Request 11.10, Duke provided the following as the basis for this adder:

> *There is not currently an ancillary market in MISO that reflects an ever-increasing level of renewables represented in the 2018 DEI IRP. With increasing amounts of renewables the day ahead forecast error and inter hourly volatility increases, which requires the utility to carry more reserves to meet the associated ancillary requirements. In the Carolinas, Duke Energy currently has over 3,000 MWs of solar generation installed today and is expected to increase to over 8,000 MWs by 2030. In 2018 Duke Energy published a study conducted by Astrape Consulting which evaluated the incremental ancillary impact of adding additional solar in the Carolinas. This study supports, as solar as a percentage of total energy grows, so does the cost associated with ancillaries. Incrementally increasing solar from 5% to 10% of energy served in DEC and DEP increased the impact of ancillary cost over 5 $/MWhrs (4% to 6% energy served by solar in DEC added 4.38 $/MWhrs and 9% to 10% of every served by solar added 7 $/MWhrs) and the next 5% increment of solar in DEP added 24 $/MWhrs. Based on the results of this study, the ancillary impact in the 2018 Duke Energy Indiana IRP was estimated conservatively low. The addition of the first 5% of energy served by solar included no ancillary cost and each 5% increment of energy served by solar after increased by 5 $/MWhr. For example, in Duke Energy Indiana when the amount of solar increased from 10% to 15% of total energy, the incremental amount of*

[27] Duke Energy Indiana 2018 IRP, p. 59.
[28] *Id*.

solar included a 10 $/MWhr ancillary cost adder which is much lower than the 24 $/MWhr adder from the Carolinas Astrape Consulting Study.

There are multiple problems with the use of the Astrape study as the basis for such an adder. First, Duke Energy Indiana has just 41 MW of solar on its system at present.[29] This is dramatically different than the level of solar on Duke's Carolinas system – 3,000 MW. Further, and even more importantly, Duke Energy Carolinas ("DEC") is not part of a Regional Transmission Organization ("RTO"). This is really the proper point of comparison – MISO to DEC, not DEC to DEI. MISO dwarfs Duke Energy Carolinas in size and scope, the former has a peak load of 123,454 MW[30] and the latter a peak load of 17,422 MW.[31] In addition, as of December 2018, "MISO had 313 MW (ICAP) of in front of the meter solar and 297 MW (ICAP) of registered behind the meter solar in commercial operation." [32] In other words, *existing solar capacity in MISO is less than a half a percent of peak load whereas solar in DEC's service territory is over 17% of peak*. For these reasons and without knowing anything about the merits of the Astrape study, it was wholly inappropriate for Duke to have used the study as the basis for any kind of solar adder.

Second, the North Carolina Utilities Commission ("NCUC") just issued an order directing DEC to use a much lower ancillary services charge of $1.10 per MWh and to submit its study methodology to a third party for independent review.[33]

Lastly, the manner in which the solar adder was applied contradicts Duke's argument for using it. The adder was only used in System Optimizer, but not Planning and Risk, as a kind of hurdle rate for the selection of solar. Duke's NPV calculations pull production costs from Planning and Risk and only capital costs from System Optimizer. If these costs were real, they ought to be part of the NPV calculation and, because they were not, Duke is effectively admitting that it does not expect that it will actually incur the costs represented by the solar adder.

Duke also chose to model solar resources with a 50% capacity contribution in the months of [redacted] but a 0% capacity contribution in the months of [redacted]. Current MISO rules say that new solar should receive a 50% capacity credit. As is true for the reserve margin requirement, current MISO practice ought to serve as the base case assumption, Indiana's IRP rules on clear on this point. While we do not think solar is likely to have a 50% capacity credit in the winter under a seasonal construct, we also do not think it will be zero. Either way, it does not matter so long as MISO's PRMR is properly modeled – as applying only to the MISO coincident peak.

Duke placed annual caps on the total amount of all new resources that could be selected in System Optimizer. However, Duke placed more onerous constraints on wind and battery resources compared to new gas combined cycle and combustion turbine units. Duke limited the annual additions of wind to

[29] Duke Energy Indiana 2018 IRP, p. 38.
[30] Peak load reported for planning year 2018. Retrieved from https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf
[31] 2017 Summer Peak load reported from EIA Form 861.
[32] MISO Wind & Solar Capacity Credit Planning Year 2019 – 2020. Retrieved from https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf
[33] See https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=160a6904-0a9d-40cb-bc33-1bf69184e058

250 MW, while the constraint on combined cycles and combustion turbines was 3,100 MW and 3,225 MW, respectively. Duke provided no rationale for how it determined these arbitrary constraints.

3.5 DEMAND-SIDE MANAGEMENT

The selection of the "optimal" level of energy efficiency through this IRP is unavoidably influenced by all the modeling issues we discuss in these comments. Where units are artificially kept online through incorrect reserve margins or unfounded restrictions on those units' retirement (see also Section 5.2), where costs of power plants are inaccurately estimated (see Section 5.1), etc., the selection of energy efficiency will not be optimized. Energy efficiency is most likely to be chosen by the model when it can actually compete with supply-side resources to fill capacity and energy needs. Therefore, there is no way to construe any of Duke's modeling runs as identifying the optimal level of energy efficiency to be implemented next year, two years down the road, or longer.

Even with the modeling flaws we have so far addressed, there are additional flaws specific to energy efficiency that would need to be addressed before Duke's IRP could reasonably serve as the basis for selection of a specific energy savings level. These flaws include:

1. Costs that are inconsistent with Duke's actual costs of implementing energy efficiency;
2. Misapplication of the half-year savings convention for energy efficiency;
3. The use of the incorrect transmission loss figure to translate savings from the meter to the generator; and
4. Lack of an avoided transmission and distribution ("T&D") estimate in the selection of energy efficiency.

We take each one of these issues in turn. During the IRP stakeholder process, we alerted Duke to the fact that the modeled costs for its programs were generally substantially higher than its forecasted costs of DSM. There is no uniform reporting of energy efficiency savings data in Indiana which makes it difficult to be precise about these estimates, but we used Duke's real discount rate and its reported portfolio measure life from a prior operating plan to calculate the values in Table 5.

Table 5. Estimated Portfolio Levelized Costs from Duke DSM Programs (2018$ per kWh)

2012	$0.015
2013	$0.020
2014	$0.019
2015	$0.019
2016	$0.021
2017	$0.017
2018	$0.018

In contrast, the estimated levelized costs of Duke's bundles in the IRP are almost across the board higher, often nearly twice as high or more. Confidential Table 6 also reports levelized costs in 2018 dollars. Note that Years 1-3 are 2018-2021 costs, i.e., for bundles that are not selectable, and are oftentimes much lower than the levelized costs for the same bundle in subsequent years. All figures in Confidential Table 6 are projections and are not based on actual Duke data.

Confidential Table 6. Duke Energy Levelized Costs of Energy Efficiency Bundles

RESIDENTIAL				
	Time	Real Levelized $/MWh		
Load Shape	Bucket	Tier 1	Tier 2	Tier 3
Lighting - Indoo	Year 1-3	[redacted]		
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Lighting - Outdc	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Mode 3	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Mode 3 - Summer Only & Pool Pumps	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Old Behavioral	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
New Behavioral	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			

NON-RESIDENTIAL				
	Time	Real Levelized $/MWh		
Load Shape	Bucket	Tier 1	Tier 2	Tier 3
Flat - Daytime	Year 1-3	[redacted]		
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Flat - Nightime	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Flat - Year Round	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Mode 3 + Behavioral	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			
Mode 3 - Summer & Shoulder Only	Year 1-3			
	Year 4-6			
	Year 7-9			
	Year 10-14			
	Year 15-20			

Duke's response to this issue was at best confused and at worst intentionally misleading and untrue:[34]

> *The Company disagrees with CAC's characterization of the levelized cost per KWh…between 2012 and 2019. It appears that CAC may have incorrectly used a single portfolio level analysis to determine their levelized costs, which does not properly account for the variety of measure lives of the various programs and measures offered by the Company.*
>
> *When analyzed correctly, the levelized costs during the 2012-19 period range from $0.015 to $0.042/first year KWH including actual values from the most recently filed cost recovery year (2017) of $0.042/first year KWh.*

We do not know how or where Duke derived these costs, because, for example, our estimate of 2017 levelized cost is $0.017 per kWh, much less than $0.042 per kWh. It is possible that Duke is simply confused because it incorrectly conflates first year cost (measure costs divided by first year measure savings) with levelized cost (measure costs levelized over the entirety of their life divided by a year's worth of savings). More importantly, it is entirely appropriate to compare portfolio levelized costs to

[34] See Duke Response to Informal CAC Data Request 3.1.

the bundle levelized costs, e.g. Table 5 to Confidential Table 6, because even though the bundles may all have different measure lives, if nearly all are substantially greater in levelized cost than Duke's actual costs, as is the case here, then it defies mathematics that the portfolio levelized cost could be significantly lower. That is, the whole cannot be significantly less costly than its parts. When asked about this issue in a different way, specifically with respect to Duke's 2018 DSM performance, the Company simply stated, "Due to the timing of the modeling included in the IRP, the Company did not make any updates to the impacts or costs to update 2018 for actual results."[35]

In response to our first version of IRP comments filed in Cause No. 45253, Mr. Park says that, "Furthermore, the CAC has stated 'Duke's portfolio levelized costs have ranged from $.015 to $.029 per MWh from 2012 to 2019.' However, in the table provided by Ms. Sommer in this proceeding, the highest value shown is $0.21/KWh, demonstrating inconsistency."[36] There is no inconsistency. The numbers cited should have read "per kWh" rather than "per MWh", but otherwise they are different than our table because they are in nominal dollars and because the highest value was based on planned, not actual, 2019 savings. Mr. Park then presents his own estimate of Duke's historic levelized cost of energy efficiency. We have not yet been able to review his workpaper, but, assuming it is correct, it does not support the levelized bundle costs in Confidential Table 6, many of which are much higher in cost. That these costs come from Nexant is a non-explanation. There should be a quantifiable reason that bundles would be projected to be, on average, much higher in cost than prior years. Duke has not produced such a reason.

A second substantial error occurs because Duke uses a "half-year" convention to model energy efficiency savings. Duke explains this process as follows:

> *The term "half year convention" was used by the Company in prior responses to questions by CAC to attempt to simplify the explanation of the process required to model the way in which participation in EE programs is added throughout a given year in the forecast. This modeling assumes that, if a given number of EE measures are expected to be added during a year, they will be added in 12 even portions. Thus, at the time of the Summer Peak in the IRP, roughly half of the savings for a given year will be realized by that point.* [37]

[35] Duke Response to Informal CAC Data Request 13.3.
[36] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 16, lines 10 – 13.
[37] Duke Response to Informal CAC Data Request 13.1.

What is missing from this explanation is that the "half" a year's worth of savings from the prior year also should be reflected in the total savings. Put another way, if the Market Potential Study ("MPS") assumes that all savings can happen immediately starting on January 1, 2020 and Duke adjusts those savings in System Optimizer to reflect their actual implementation as happening evenly throughout the year, then roughly half the MPS 2020 savings will occur in 2021 and should be added to the modeled 2021 savings total. But Duke does not make this adjustment correctly. As Confidential Table 6 implies, each bundle is modeled in three to five year increments with years 4 – 6 corresponding to 2021 to 2023. Rather than putting a half year's worth of 2020 savings into the 2021 total, Duke models each starting year in each increment as having only a half year's worth of savings. So for years 2021, 2024, 2028, and 2033, roughly half of the incremental savings are missing and that deficit is carried through for the remainder of those savings' lives. This flaw also serves to render Duke's modeling of EE as meaningless as the basis for the selection of the optimal level of savings in its DSM plan, Cause No. 43955 DSM 8.

Mr. Park again claims that we are wrong about this[38] when his hypothetical explanation in his testimony shows that it is, in fact, Duke that is wrong. Mr. Park argues that Duke follows the convention in the top half of Table 7, but it does not, in fact, do this.[39] The "leftover" savings from 2023 are not modeled in either the 2021-2023 bundle nor in the 2024-2026 bundle; they are missing.

Table 7. Example of Duke Claimed Half-Year Methodology to Actual Methodology

			2021	2022	2023	2024	2025	2026	2027
Claimed Duke Energy Indiana	2021-23	Half Year Incremental	5,000	10,000	10,000	5,000	-	-	-
	2024-26	Half Year Incremental				5,000	10,000	10,000	5,000
		Total Incremental	5,000	10000	10,000	10,000	10,000	10,000	5,000
		Total Cumulative	5,000	15000	25000	35000	45000	55000	60000
Actual Duke Energy Indiana	2021-23	Half Year Incremental	5,000	10,000	10,000	0	-	-	-
	2024-26	Half Year Incremental				5,000	10,000	10,000	5,000
		Total Incremental	5,000	10000	10,000	5,000	10,000	10,000	5,000
		Total Cumulative	5,000	15000	25000	30000	40000	50000	55000

A third error occurred with the translation of savings at the meter to savings at the generator. Energy efficiency always saves energy at the margin because transmission and distribution losses are greater at the margin than on average. So energy efficiency savings should be converted from meter to generator using the marginal rather than average line loss.[40] Making this correction would increase modeled savings by perhaps 10% each year or more.

A fourth error is the omission of avoided transmission and distribution ("T&D") costs when assessing the economically optimal level of efficiency. Energy efficiency can defer or avoid T&D investments in meaningful ways, and its avoided cost for this purpose ought to be included in the evaluation of energy efficiency. Some IRP models can incorporate this value explicitly, and some cannot. We do not know which is true of System Optimizer, but if it is the latter, then bundle costs can be adjusted downward to

[38] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 18, line 9 to page 21, line 9.
[39] See Confidential Attachment CAC 3.1-A provided in informal discovery.
[40] See also: www.raponline.org%2fwp-content%2fuploads%2f2016%2f05%2frap-lazar-eeandlinelosses-2011-08-17.pdf&c=E,1,HjxtVV5dQDvjoqiXWS68v-EE36FpRx6XiPfb90lHHC0IctwVnJxD8qFkQ7JLeLZSjmusH4bajUytaIq2Hrq0U5jLlSCGk-4avSgxXXqskPQ,&typo=1

account for this benefit. Duke should have included this avoided cost, and its omission is a de facto estimate of zero avoided cost which we find highly improbable. Indeed, this analysis is explicitly required by 170 IAC 4-7-8(c)(6) which says that the IRP must include, "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."

3.6 OTHER ISSUES WITH DUKE'S IRP

Though required by Indiana's IRP rule, Duke gave no "brief description of the [power flow] model(s), focusing on the utility's Indiana jurisdictional facilities…" In response to Informal CAC Data Request 11.18, Duke stated "No power flow modeling was done for purposes of the 2018 IRP." And at page 174 of the IRP, it simply states:

> *Duke Energy Indiana's planning criteria are filed under the FERC Form 715 Part 4. The Company adheres to any applicable NERC and RFC Reliability Standards, and to its own detailed planning criteria, which are shown in the following paragraphs. Violations of these criteria would require expansion of transmission system and/or new or revised operating procedures. Acceptance of operating procedures is based on engineering judgment with the consideration of the probability of violation weighed against its consequences and other factors.*

In the IRP, Duke claims that, "The avoided costs used in screening the EE and DR programs in the Market Potential Study to determine the Economic Potential were based on information in the New Portfolio Program filing (Cause No. 43955 – DSM4) made with the Commission. The Company considers this information to be a trade secret and confidential and competitive information. It will be made available to appropriate parties for viewing at Duke Energy Indiana offices during normal business hours upon execution of an appropriate confidentiality agreement or protective order."[41] This information should be viewable to those parties without a competitive interest who have signed the confidentiality agreement. Only allowing for the information to be viewed at Duke's offices provides no meaningful transparency of the avoided cost calculation.

[41] Duke Energy Indiana 2018 IRP, p. 168.

4 Energy and Demand Forecasts

Section 4 focuses on how Duke performed regarding meeting the requirement of 170 IAC 4-7-5 of the Indiana IRP Rule regarding energy and demand forecasts. Please see Table 8 below for our findings.

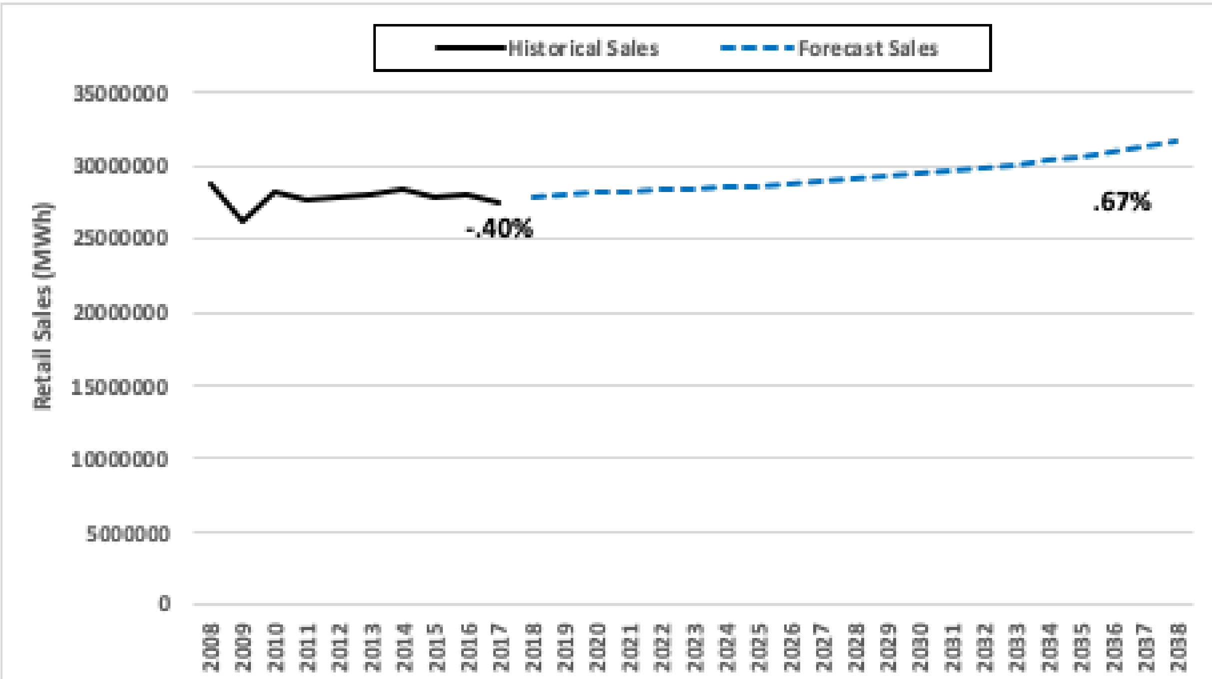
Table 8. Summary of Duke's Achievement of Indiana IRP Rule 170 IAC 4-7-5

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.	Met
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.	Mostly
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.	Mostly
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	Partial
4-7-5 (a)	(8) Justification for the selected forecasting methodology.	Partial
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.	Partial
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

As mentioned in Section 2, Duke used Itron's SAE model to forecast sales for its 2018 IRP. Regardless of the methodology chosen, Duke had virtually no discussion of its load forecast in the stakeholder workshops. Duke presented two slides showing historical and forecasted demand and energy in stakeholder workshop 3, but these slides only depicted the forecast for Duke's system and not a forecast for each of the customer classes or the methodology used to create these forecasts.[42]

Duke predicts a higher growth rate in sales and peak demand than it has experienced over the last eleven years. Figure 4, below, shows how Duke's forecast compares to the historical.

Figure 4. Comparison of Duke's Actual Retail Sales to Forecasted Sales (MWh)

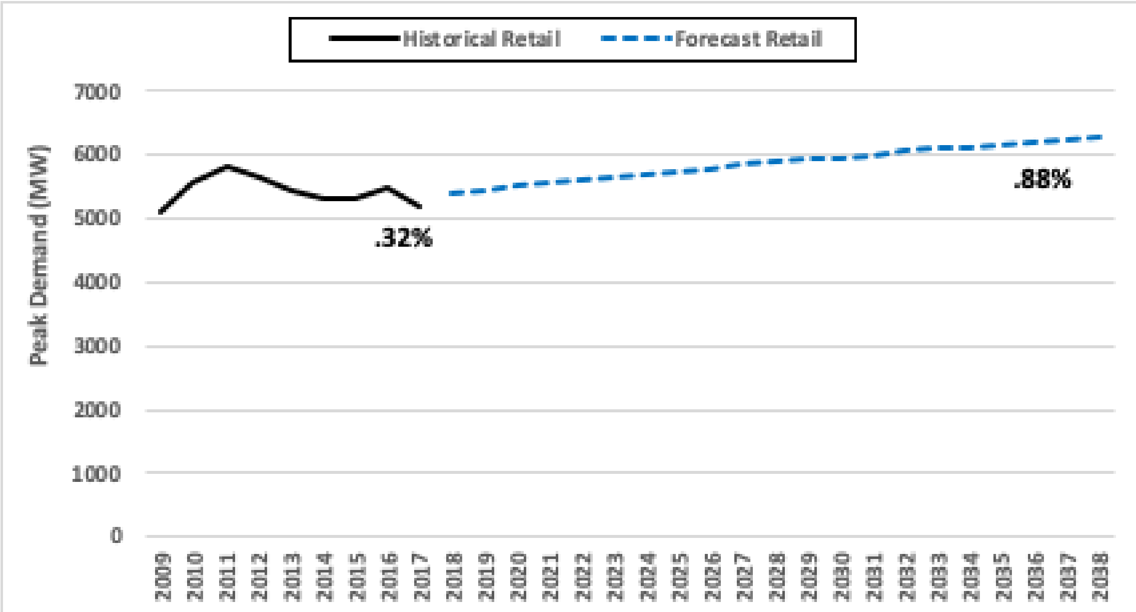


**Data from Table B.1 of Duke's 2018 IRP*

Duke is also forecasting an increase in its peak demand over the planning period. Figure 5, below, highlights the difference between the historical and forecasted peak demand and also includes the peak demand when considering the wholesale requirement customers. Duke will lose some wholesale requirements customers, so their contribution to peak demand falls slightly during the planning period. We recognize that the projection does not include new utility-sponsored DSM while the historical does. We would also note that had Duke complied with Rule 170 IAC 4-7-6 (a)(6) which requires, "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", then this comparison accounting for DSM would have been readily available.

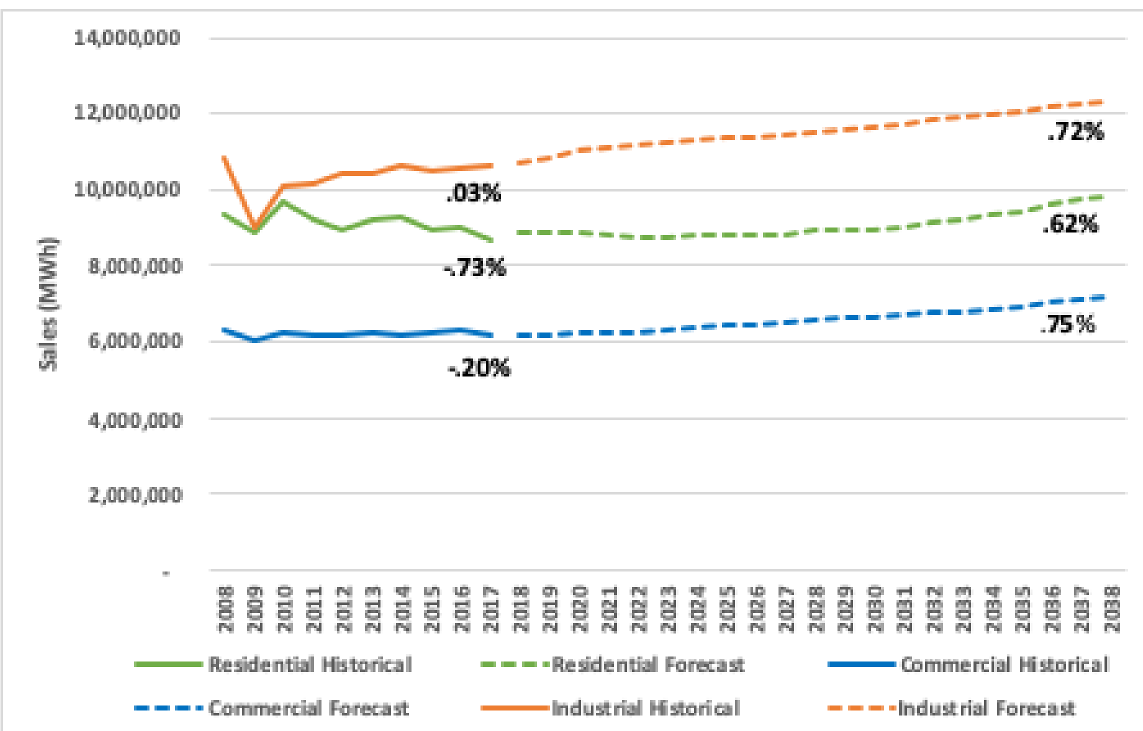
[42] Duke Energy Indiana Stakeholder Workshop #3 held on April 17, 2018. Powerpoint slides retrieved from https://www.duke-energy.com/_/media/pdfs/for-your-home/indiana-irp/in-irp-meeting-slides-mtg-3.pdf?la=en

Figure 5. Comparison of Duke's Actual to Forecasted Retail Peak Demand (MW)[43]



Duke projects increasing sales in all three sectors as depicted in Figure 6, below. Duke forecasts industrial sales at higher than historical levels since 2008, .72% compared to a historical rate of .03%. In the residential class the historical rate is -.20% while the forecasted average annual growth rate is .75%. And amongst commercial customers, the historical rate was -.73% while the forecasted average annual growth rate is .62%.

Figure 6. Comparison of Actual and Forecasted Sales by Customer Class[44]



The driver of increased industrial sales is not an increasing numbers of customers but increased average utilization per customer (see Figure 7 below). Increased sales for the customer class is also driven by an increase in the average utilization per customer as depicted in Figure 8 below.

[43] This only reflects the peak from retail customers. Duke is projecting a decline in the wholesale requirements peak demand over the planning period. Peak demand from wholesale requirements customers is [redacted] MW in 2018 and declines each year in the planning period until it reaches [redacted] MW in 2038.
[44] *Data from Table B.1 of Duke's 2018 IRP, p. 112.*

Figure 7. Comparison of Actual to Forecasted Average Use for Industrial Customers

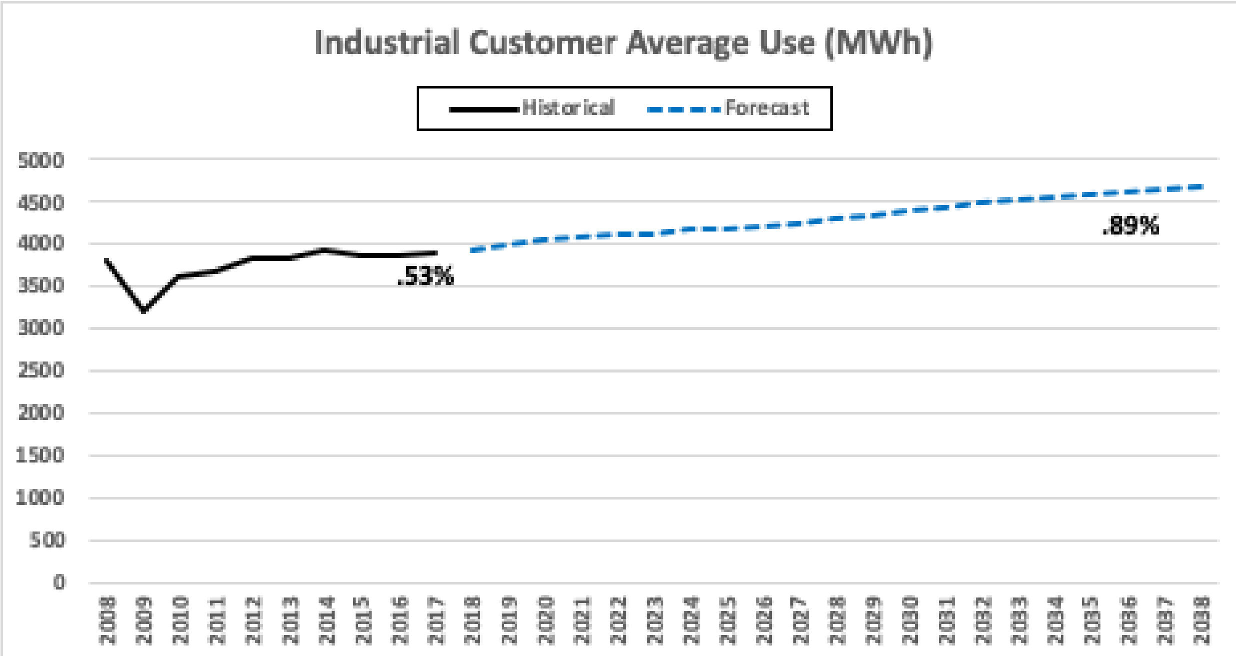
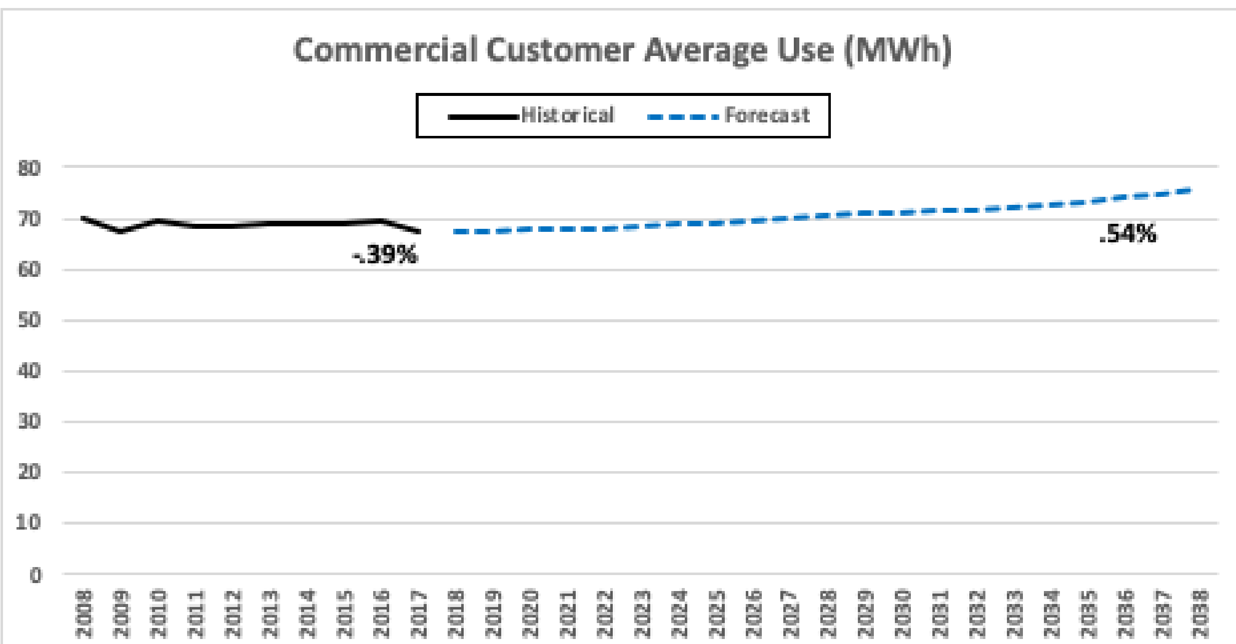


Figure 8. Comparison of Actual to Forecasted Average Use for Commercial Customers



This increase has a significant impact on Duke's load forecast and merits explanation. We think the difference is unlikely to be driven by EE impacts because so many of Duke's industrial customers, 90% as a percentage of eligible load as of Dec. 31, 2018, have opted out of its EE programs. On the commercial side, we do not know what the explanation for the rate of growth might be.

5 Description of Available Resources

Section 5 focuses on Duke's performance in meeting the requirements of 170 IAC 4-7-6 of the Indiana IRP Rule regarding the description of available resources. Please see Table 9 below for our findings.

Table 9. Summary of Duke's Achievement of Indiana IRP Rule 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.	Mostly
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.	Partial
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.	Not Met
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.	Not Met
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.	Partial
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.	Not Met

5.1 NEW SUPPLY-SIDE RESOURCES

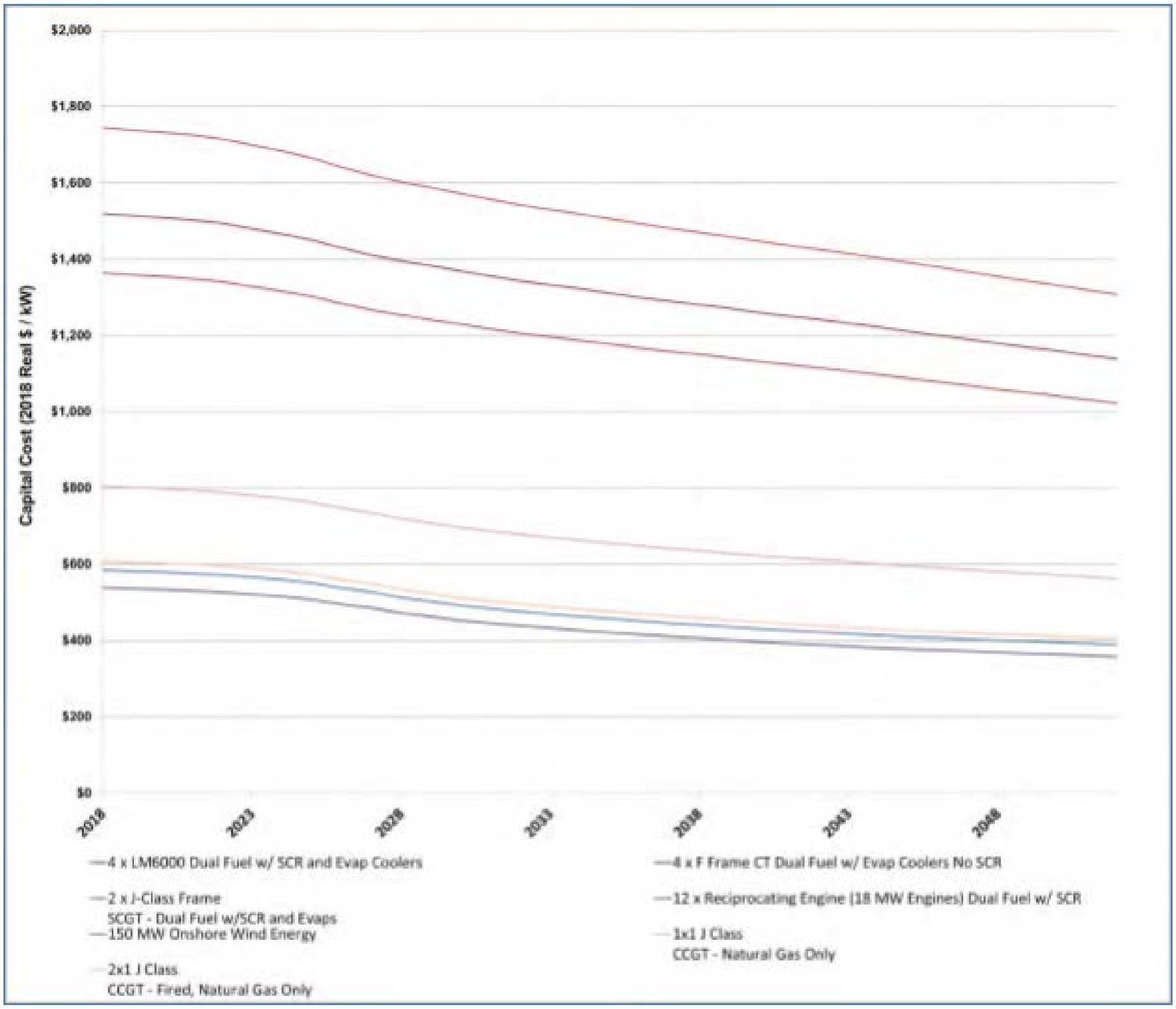
Duke described the development of its thermal and wind capital cost forecast as follows:

> *A capital cost forecast was developed with support from a third party to project not only Renewables and Battery Storage capital costs, but the costs of all generation technologies technically screened in. The Technology Forecast Factors were sourced from the EIA's Annual Energy Outlook (AEO) 2017 which provides costs projections for various technologies through the planning period as an input to the National Energy Modeling System (NEMS) utilized by the EIA for the AEO.*
>
> *Using 2018 as a base year, an "annual forecast factor is calculated based on the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices." (NEMS Model Documentation 2016, July 2017)*
>
> *These forecast factors were blended with additional third-party capital cost projections for more rapidly developing technologies (i.e. Solar PV, Battery Storage) in order to provide a consistent forecast through the planning period for all technologies evaluated. The resulting Capital Cost changes for the technologies shown in Table C.1 are depicted below in Figure C.5* [45]

Figure 9 reproduces Figure C.5 from the IRP and shows the capital cost forecasts for select technologies not including solar or battery storage. Duke's projections for renewable and battery storage costs were provided in a data file to stakeholders, but are not contained in the IRP – a significant omission in Duke's IRP submission.

[45] Pages 131-132 of Appendix C of the Duke 2018 IRP.

Figure 9. Reproduction of Figure C.5 from Duke Energy Indiana 2018 IRP [46]



Duke's description of how it developed the costs of all resources does not provide much meaningful information. It does not explain why Duke chose the U.S. Energy Information Administration ("EIA") over several other capital cost sources that are more frequently used and considered more accurate sources for cost information particularly for renewables, i.e., NIPSCO's Request for Proposal ("RFP") responses and National Renewable Energy Laboratory's ("NREL") Annual Technology Baseline ("ATB") Low Case. It does not explain why the "annual forecast factor" for metals would be necessary or preferable to, again, other cost sources that provide a long-term forecast of capital costs. Indeed, there is significant evidence that Duke's projections for renewables, at least, are far too high.

Confidential Table 10, below, illustrates the average bid price that NIPSCO received for solar, wind, and solar + storage resources for its 2018 RFP for use in its 2018 IRP; the average, median, min, and max from the cost forecasts NIPSCO reviewed prior to the IRP; and then Duke's reference case values. The average bid price received in response to the RFP demonstrates how quickly costs for renewables can come down and how different those costs can be from third party data sources. The average NIPSCO

[46] Duke Energy Indiana 2018 IRP, Appendix C, p.133.

RFP bid price for solar resources was *lower than the average, median, minimum, and maximum from the third-party data sources*. The average NIPSCO 2018 RFP bid price for wind was *lower than the capital cost average, median, and max* from those sources and only slightly higher than the minimum value.

***Confidential** Table 10. Duke Capital Cost Comparison to NIPSCO 2018 RFP Bids and Data Sources*[47]

	Duke IRP ($/kW)	Current Capital Costs ($/kW)				NIPSCO RFP ($/kW)
	Reference	Average	Median	Min	Max	Average Bid Price
Solar**	[redacted]	$1,715	$1,489	$1,184	$2,429	$1,180
Wind	[redacted]	$1,762	$1,719	$1,461	$2,026	$1,493
Li-Ion Battery (4hr)**	[redacted]	$2,163	$2,214	$1,350	$3,192	-
Solar + Storage		-	-	-	-	$1,212

**Costs reported in 2018 $/kW*
***Capital costs from year 2021 of Duke's forecast*

NIPSCO's 2018 RFP bid prices are more timely and more up to date than Duke's forecast and would serve as a more accurate basis for capital cost projections (note that CAC and others asked Duke to use NIPSCO's 2018 RFP bid prices as a proxy in a letter to Duke dated Dec. 4, 2018). While Duke included a sensitivity for a lower capital cost forecast for new solar resources, the starting capital cost for the low-cost sensitivity is higher than the average bid price received by NIPSCO in its 2018 RFP. In addition, Duke's "low" forecast also keeps the capital cost the same for the first ten years of the forecast and then increases. Confidential Table 11 shows Duke's capital cost forecast for new solar resources under the reference case and low-cost sensitivity.

[47] NIPSCO 2018 IRP, Figure 4-7 on p. 53 and Figure 4-11 on p. 56.

Confidential Table 11. Duke Capital Cost Forecasts for New Solar Resources[48]

	Reference Case ($/kW)	Low Cost Sensitivity ($/kW)
2019	[redacted]	
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		

[48] Capital cost information from confidential Data Summary for Stakeholders workbook provided by Duke.

Furthermore, this low-cost forecast is not really "low", particularly when compared to the projected cost decreases that are forecasted in NREL's Annual Technology Baseline. Confidential Table 12 below compares the percentage difference in cost between each year in Duke's capital cost forecast for solar resources with NREL's ATB. For the first ten years of Duke's forecast for the reference case, the percentage decline in costs is slightly higher than the mid case in the ATB; however, it is significantly less than the low case in the ATB. Duke is also projecting that the costs of solar will start to rise after the first ten years of the forecast, which is not consistent with the mid and low case in the ATB.

Confidential Table 12. Comparison of Duke's Solar Capital Cost Forecast Decline to 2018 NREL ATB

	Duke		NREL ATB	
	Reference	Low Cost	Low	Mid
2020	[redacted]		-4.66%	-5.88%
2021			-4.16%	-5.21%
2022			-2.83%	-1.13%
2023			-2.91%	-1.14%
2024			-3.00%	-1.16%
2025			-3.10%	-1.17%
2026			-3.19%	-1.18%
2027			-3.30%	-1.20%
2028			-3.41%	-1.21%
2029			-3.53%	-1.23%
2030			-3.66%	-1.24%
2031			-1.67%	-0.86%
2032			-1.69%	-0.87%
2033			-1.72%	-0.88%
2034			-1.43%	-0.89%
2035			-2.88%	-0.90%
2036			-2.34%	-0.90%
2037			-2.39%	-0.91%

With respect to the costs for combined cycles, Duke has the opposite problem. Duke modeled a 1239 MW 2x2x1 Advanced Combined Cycle ("CC")[49] with a capital cost of [redacted] $/kW ($2018)[50] though it declines further from there as shown in Figure 9. The first year the model could select this resource is [redacted]. While Duke does not explain what is meant by an "Advanced" Combined Cycle, the capital cost

[49] Duke Energy Indiana 2018 IRP, p. 129.
[50] Information from Data Summary for Stakeholders provided by Duke.

that Duke modeled for this CC is much lower than other, comparable CC projects under development in the United States.

Table 13 shows all the CC projects with a capacity of 1000 MW or greater. The average capacity of these projects is 1209 MW and the average capital cost is $950 per kW.

Table 13. Project Information for Combined Cycle Units

Project Name	New Capacity (MW)	State, Province, or Admin Region	Year in Service	Current Development Status	Estimated Construction Cost ($000)	Capital Cost ($/kW)
North Bergen Liberty Generating Project	1200	NJ	2022	Early Development	1500000	$1,250
South Field Energy	1132	OH	2021	Construction Begun	1300000	$1,148
CPV Three Rivers Energy Center	1250	IL	2021	Early Development	1312500	$1,050
Clear River Energy Center (Burrillville Power Plant)	1080	RI	NA	Early Development	1000000	$926
Lincoln Land Energy Center (Pawnee Natural Gas Plant)	1100	IL	2023	Early Development	1000000	$909
Blue Water Energy Center (Belle River Combined Cycle Plant)	1146	MI	2022	Construction Begun	1000000	$873
Cadiz Combined Cycle Plant (Harrison County Industrial Park)	1050	OH	2021	Early Development	900000	$857
Indeck Niles Energy Center	1171	MI	2022	Advanced Development	1000000	$854
Guernsey Power Station	1875	OH	2022	Advanced Development	1600000	$853
Big Bend CC Project	1090	FL	2023	Construction Begun	853000	$783
Average Capacity (MW)	**1209**					
Average Capital Cost ($/kW)						**$950**

Duke's much lower capital would have the effect of understating the likely cost of building a CC and significantly biasing the Company's modeling results in favor of combined cycle technology.

Amazingly, Mr. Park implies that because Navigant supplies its renewables cost data that somehow makes it more reliable than looking to actual data from a recent RFP in Indiana.[51] He then makes the incredible statement despite the multitude of utilities acquiring renewables and battery storage all over the country that, "The lesson here is that in an environment of low gas prices and no carbon regulation, solar does not become economic until the early to mid-20's."[52] Duke's IRP is a self-fulfilling prophecy, not demonstrative evidence that contradicts the experience of so many other utilities in Indiana and across the country.

5.2 RETIREMENT ANALYSIS

In the IRP, Duke describes its retirement analysis as a three step process: [53]

1. *Perform an initial System Optimizer run with no units eligible for retirement*
2. *Capacity factors from the first step are used as inputs to a spreadsheet tool to forecast future maintenance capital expenditures and fixed operating costs*
3. *Use the fixed cost forecasts from the second step as inputs to the second System Optimizer run.*

[51] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 8, line 13.
[52] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 8, line 22 to page 9, line 2.
[53] Duke Energy Indiana 2018 IRP, pp. 28-29.

Duke evaluated only existing pulverized coal units, but not Edwardsport for retirement and no units aside from Gallagher Units 2 and 4 were permitted to retire before 2024. Duke argued that this constraint on retirements was necessary due to the "time it would take for the company to prepare to take a unit offline (including any regulatory filings and design, permitting, and construction of replacement resources), as well as make any required transmission upgrades."[54] In response to Informal CAC Data Request 8.5, Duke stated, "Based on the Company's analysis, assuming retirements cannot be accommodated by 2024 is a reasonable assumption." Duke's claim is completely at odds with the very documents it provided CAC to support that response.[55] Confidential Attachment CAC 8.5-C, which is included as Appendix 1 Confidential of this report, shows the following:

1. The retirement of [redacted] requires no transmission upgrades and therefore could happen well before 2024.
2. The retirement of all five Gibson Units together requires [redacted] years of lead time and just $[redacted] worth of upgrades meaning that the earliest retirement date for Gibson Units [redacted] should have been [redacted] not 2024.

Table 14, below, shows the net profit/loss at Duke's Gibson and Cayuga units from 2014 to 2018. Revenue from the generating units was approximated by taking the monthly average of historic daily locational marginal price ("LMP") prices from MISO in addition to MISO PRM capacity prices. The total O&M expense for the plants as reported to EIA and the Federal Energy Regulatory Commission ("FERC") were allocated to each unit proportionally by that unit's capacity. Many of the units have been operating at substantial losses in the last five years, especially Gibson Units 2, 4, and 5, in addition to Gallagher Units 2 and 4.

[54] Duke Energy Indiana 2018 IRP, p. 58.

[55] The Commission should also be aware of Duke's behavior with regard to CAC's repeated requests to Duke for the basis for limiting coal plant retirements to 2024 and beyond in its IRP and for any supporting documentation including any modeling performed that assessed transmission upgrades needed to retire any of Duke's coal units. CAC asked for this information in the 2018 IRP Stakeholder Process with CAC Data Request 8.5, and within Duke's base rates case, Cause No. 45253, with CAC Data Requests 3.3 and 7.4. Duke first provided an incomplete and unhelpful three-sentence response. After CAC's counsel reached out to Duke to receive a more complete response in the IRP Stakeholder Process, Duke merely provided a four-page PDF (Appendix 1 Confidential) that reported transmission upgrades and upgrade costs, i.e., nothing underlying how or why those upgrades would be needed to retire any coal units. In the base rates case, CAC attempted to use the discovery process to get the requested documents, and Duke again provided the four-page PDF document, i.e., another unresponsive response from Duke. Finally, after more prodding from CAC, Duke finally agreed to provide the requested information. Due to the fact that Duke did not provide this information that CAC began requesting on June 6, 2019, until October 14, 2019, these Duke IRP comments are being supplemented with the attached transmission study by Mott MacDonald (Appendix 2). More analyses may also be provided on this issue in particular.

Table 14. Profit(Loss) Estimate of Gibson, Cayuga, and Gallagher Units

		2014	2015	2016	2017	2018
Gibson Unit 1	*Revenue from MISO*	*$136,835,581*	*$102,122,131*	*$84,713,334*	*$120,110,993*	*$110,253,038*
	Total Cost of Operation	*$130,846,811*	*$106,644,099*	*$111,245,686*	*$106,442,368*	*$105,259,535*
	Profit (Loss)	***$5,988,770***	***-$4,521,968***	***-$26,532,353***	***$13,668,625***	***$4,993,502***
Gibson Unit 2	*Revenue from MISO*	*$150,353,857*	*$94,062,072*	*$102,368,098*	*$98,533,426*	*$101,420,855*
	Total Cost of Operation	*$130,846,811*	*$106,644,099*	*$111,245,686*	*$106,442,368*	*$105,259,535*
	Profit (Loss)	***$19,507,047***	***-$12,582,027***	***-$8,877,588***	***-$7,908,942***	***-$3,838,680***
Gibson Unit 3	*Revenue from MISO*	*$126,051,417*	*$63,265,796*	*$92,781,939*	*$93,418,469*	*$118,496,997*
	Total Cost of Operation	*$130,846,811*	*$106,644,099*	*$111,245,686*	*$106,442,368*	*$105,259,535*
	Profit (Loss)	***-$4,795,394***	***-$43,378,303***	***-$18,463,747***	***-$13,023,899***	***$13,237,461***
Gibson Unit 4	*Revenue from MISO*	*$111,742,715*	*$91,049,897*	*$95,393,321*	*$107,255,543*	*$102,956,206*
	Total Cost of Operation	*$130,846,811*	*$106,644,099*	*$111,245,686*	*$106,442,368*	*$105,259,535*
	Profit (Loss)	***-$19,104,096***	***-$15,594,202***	***-$15,852,366***	***$813,175***	***-$2,303,329***
Gibson Unit 5	*Revenue from MISO*	*$148,044,547*	*$58,071,813*	*$91,896,765*	*$89,005,917*	*$104,102,217*
	Total Cost of Operation	*$130,846,811*	*$106,644,099*	*$111,245,686*	*$106,442,368*	*$105,259,535*
	Profit (Loss)	***$17,197,737***	***-$48,572,286***	***-$19,348,921***	***-$17,436,451***	***-$1,157,319***

		2014	2015	2016	2017	2018
Cayuga Unit 1	Revenue from MISO	$92,018,429	$89,543,280	$71,086,176	$96,261,435	$93,784,557
	Total Cost of Operation	$94,294,143	$81,200,834	$92,479,631	$81,238,136	$96,772,610
	Profit (Loss)	**-$2,275,714**	**$8,342,446**	**-$21,393,455**	**$15,023,299**	**-$2,988,053**
Cayuga Unit 2	Revenue from MISO	$88,217,105	$47,333,426	$103,109,408	$70,432,598	$100,811,352
	Total Cost of Operation	$93,351,202	$80,388,825	$91,554,835	$80,425,754	$95,804,884
	Profit (Loss)	**-$5,134,097**	**-$33,055,399**	**$11,554,573**	**-$9,993,156**	**$5,006,468**
Gallagher Unit 2	Revenue from MISO	$21,495,850	$8,516,304	$6,866,859	$4,575,207	$6,164,382
	Total Cost of Operation	$23,965,782	$15,816,558	$11,692,658	$8,191,890	$12,889,772
	Profit (Loss)	-$2,469,932	-$7,300,254	-$4,825,799	-$3,616,683	-$6,725,390
Gallagher Unit 4	Revenue from MISO	$21,376,490	$7,735,888	$7,294,775	$4,196,976	$4,334,107
	Total Cost of Operation	$23,965,782	$15,816,558	$11,692,658	$8,191,890	$12,889,772
	Profit (Loss)	-$2,589,292	-$8,080,670	-$4,397,883	-$3,994,914	-$8,555,665

**Based on MISO LMP price data, MISO capacity price data, and reported operating and maintenance expense for plants.*

Table 14 is conservative in the sense that it includes no capitalized maintenance or other capital expenditures, no administrative and general expenditures, and no property taxes.

While Duke included fixed O&M for its existing units in Step 1 of its retirement analysis, it then removed the fixed O&M for all coal units in the second System Optimizer ("SO") run. In addition, Duke did not include any fixed O&M for existing resources aside from the Purdue Combined Heat & Power ("CHP") project in its modeling of the Moderate and Aggressive Transition alternative portfolios in System Optimizer.[56] Nor did Duke include fixed O&M for any of its existing resources in the Planning and Risk production cost modeling.[57] Again, because Planning and Risk ("PaR") is the source of production costs, this is really problematic for comparison of the modeling results. It means, for example, that the

[56] In addition, we do not know how/if fixed costs were modeled in the two Rapid Decarbonization portfolios because they were not modeled in System Optimizer but instead were created in spreadsheets.
[57] Since Duke performed its production cost modeling without the fixed O&M for its existing resources, these costs were not rolled up into the NPVs of the portfolios.

Aggressive and Moderate Transition portfolios are not comparable to each other because they include different unit retirement dates without accounting for the avoided fixed costs arising from those retirements. We do not know why Duke would have done this, because not only is it contrary to modeling best practice, but it takes extra work to remove those costs from the model.

Taking Duke's own calculation of net profit for all of its coal units from PaR combined with the fixed O&M in the corresponding SO retirement run produces the numbers in Confidential Table 15.

Confidential Table 15. Forward Looking Profit(Loss) at Duke Coal Plants ($000)[58]

Unit	2019	2020	2021	2022	2023
Gibson 2	[redacted]				
Gibson 3					
Gibson 4					
Gibson 5					
Gibson 1					
Cay 1 SCR					
Cay 2 SCR					
Gall 2 LS					
Gall 4 LS					
Edwrdsprt IGCC					

Because Duke did not model a capacity market, there is no capacity revenue included in these figures. So we calculated the capacity price that would be necessary to make each of these units break even, as shown in Confidential Table 16.

Confidential Table 16. Capacity Value Necessary to Make Unit Break-Even (per MW-day)

Unit	2019	2020	2021	2022	2023	Average
Gibson 2	[redacted]					
Gibson 3						
Gibson 4						
Gibson 5						
Gibson 1						
Cay 1 SCR						
Cay 2 SCR						
Gall 2 LS						
Gall 4 LS						
Edwrdsprt IGCC						

For reference, Zone 6 PRA prices have never exceeded $72 per MW-day and are typically much lower; last year's value was $2.99 per MW-day, and the average is $15.40 per MW-day.[59] And prices are

[58] Based on data provided in response to CAC Data Requests 7.2 and 7.3 in Cause No. 45253.

[59] Retrieved from: https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf.

capped by MISO's gross Cost of New Entry ("CONE") calculation. For the 2019/2020 Planning Year, CONE was set at $240.49 per MW-day in Zone 6. The values in Confidential Table 16 move around because the annual fixed O&M values vary so much. Edwardsport would [redacted] even if gross CONE were maximized. The handful of red values mean that the plant is projected to be economic in that year even without capacity revenue. With so many of Duke's units needing a capacity value many times the average MISO capacity value to be economic, this is yet another indication that earlier retirement of several units ought to have been much more closely examined.

6 Selection of Resources

Section 6 describes how well Duke met the requirements of 170 IAC 4-7-7 of the Indiana IRP Rule regarding the selection of resources. Please see Table 17 below for our findings.

Table 17. Summary of Duke's Achievement of Indiana IRP Rule 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.	Partial

Duke includes a renewable 2 MW solar photovoltaics ("PV") plus 2MW / 8MWh Li-ion Battery[60] in the list of dispatchable resources considered in the economic screening. After including this resource in the dispatchable resource list, there is no further discussion about this resource and how it was evaluated for the screening process. Hybrid solar and battery systems are not a new or novel technology, but rather one at commercial scale that many utilities are adopting. The alternatives considered by Duke should have included hybrid resources and in particular hybrid resources at utility scale. We suspect, but do not know for sure, that System Optimizer cannot simulate paired solar and storage systems. Mr. Park claims that Duke can and does simulate solar plus storage systems,[61] but the list of new resources in its own modeling files contradict that. As shown in Table 18, there is no hybrid solar and storage resource.

[60] Duke Energy Indiana 2018 IRP, p. 130.
[61] IURC Cause No. 45253, Rebuttal Testimony of Scott Park at page 22, lines 16 – 18.

***Confidential* Table 18. New Supply-Side Resources in System Optimizer**[62]

[redacted]

We think it is very important that Duke select a model for future filings that can do a credible job of simulating this resource and that it actually includes hybrid systems in its modeling.

[62] Duke Response to CAC Data Request 7.2-A in IURC Cause No. 45253.

7 Resource Portfolios

Section 8 describes how well Duke met the requirements of 170 IAC 4-7-8 of the Indiana IRP Rule regarding resource portfolios. Please see Table 19 below for our findings.

Table 19. Summary of Duke's Achievement of Indiana IRP Rule 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.	Met
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.	Met
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.	Partial
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.	Not Met
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.	Not Met
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.	Partial

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.	**Not Met**

Duke selected its Moderate Transition portfolio as its preferred portfolio.[63] Four portfolios have lower costs than the Moderate Transition portfolio (Current Conditions; Slower Innovation; Reference, No Carbon; Reference Case), though they are not all comparable. Four portfolios also achieve greater greenhouse gas emission reductions than the Moderate Transition portfolio.[64] Duke explains its choice in this way:

> *Under the Moderate Transition portfolio, the resource mix will be diversified over time without committing to dramatic resource changes prematurely, preserving decision-making flexibility going into the 2021 IRP analysis and shielding customers from undue cost increases in the near-term.*[65]

Duke calls its preference to hold off on forward-thinking investments "preserving decision-making flexibility" and extols the benefits of moving slowly. It should be noted, however, that Duke's metric for greenhouse gas emissions reductions (reduction from 2005 baseline) is blind to when emission reductions occur between today and 2037, when in fact the timing of these reductions is critical to global efforts to slow climate change. Rapid greenhouse gas emission reductions with the goal of limiting cumulative emissions are imperative to actions to prevent global climate change: a reduction in emissions in 2037 is in no way equivalent to the same reduction implemented in 2020 and continued through 2037.

Duke's Moderate Transition portfolio continues to add new gas generation through 2034 claiming that this approach—planning for a large and growing share of gas generation and a smaller increase in the share of renewable generation—permits the greatest flexibility for the Company to react to evolving conditions. This wait-and-see approach undermines the objectives of the current IRP and the efforts of its stakeholders. Renewable and efficiency investments do not present unique fetters to new choices in the future. Opportunities to adjust course in response to developing conditions will be available in future IRPs regardless of the portfolio selected in this IRP. Why not, then, select the preferred portfolio based on current-day cost projections and current-day priorities? Duke fails to explain why and how investments in renewables and efficiency are "premature" or "inflexible" or provide any supporting rationale for this argument.

[63] Duke Energy Indiana 2018 IRP, p. 94.
[64] Duke Energy Indiana 2018 IRP, Table V.12, p. 93.
[65] Duke Energy Indiana 2018 IRP, p. 94.

8 Short Term Action Plan

Section 8 focuses on how well Duke performed in meeting the requirement of 170 IAC 4-7-9 of the Indiana IRP Rule regarding resource portfolios. Please see Table 20 below for our findings.

Table 20. Summary of Duke's Achievement of Indiana IRP Rule 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.	Met
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.	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.	Met
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 2018 Action Plan is a reflection of its modeling assumptions: very little changes until 2023 and even then the primary resource action, retirement of Gallagher Units 2 and 4, is merely the long delayed implementation of a decision made many years ago. Indeed, in its last IRP, Duke's preferred plan would have retired the remaining Gallagher units in 2019. The change in retirement date to 2023 is neither discussed in nor supported by the 2018 IRP. This lack of "action" is inextricably linked to the many flawed modeling assumptions that underlie Duke's 2018 IRP. Figure 10, Figure 11, and Figure 12 show that Duke plans to maintain its energy mix largely in the same manner that it currently exists now until 2028 when its preferred plan would add gas capacity. Renewables and energy efficiency grow only slightly, and net purchases remain largely the same.

Figure 10. Duke 2018 Energy Mix

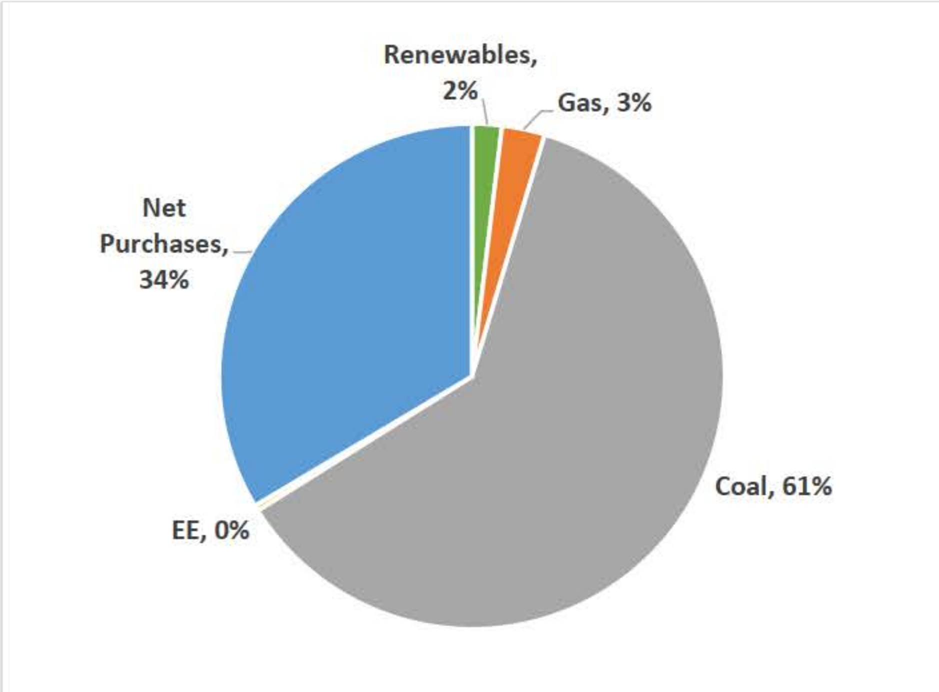


Figure 11. Duke 2023 Energy Mix

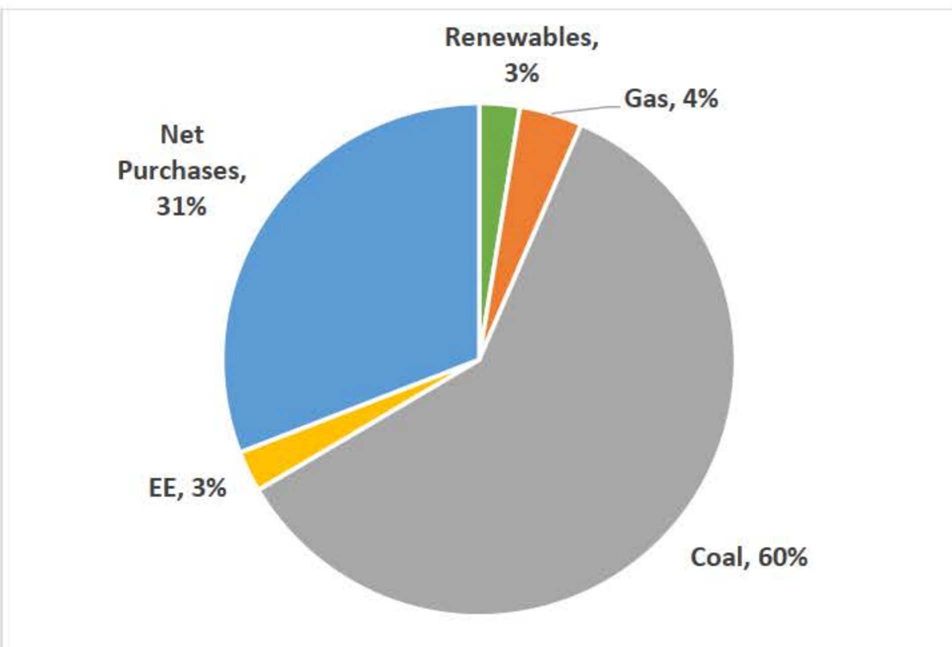


Figure 12. Duke 2028 Energy Mix

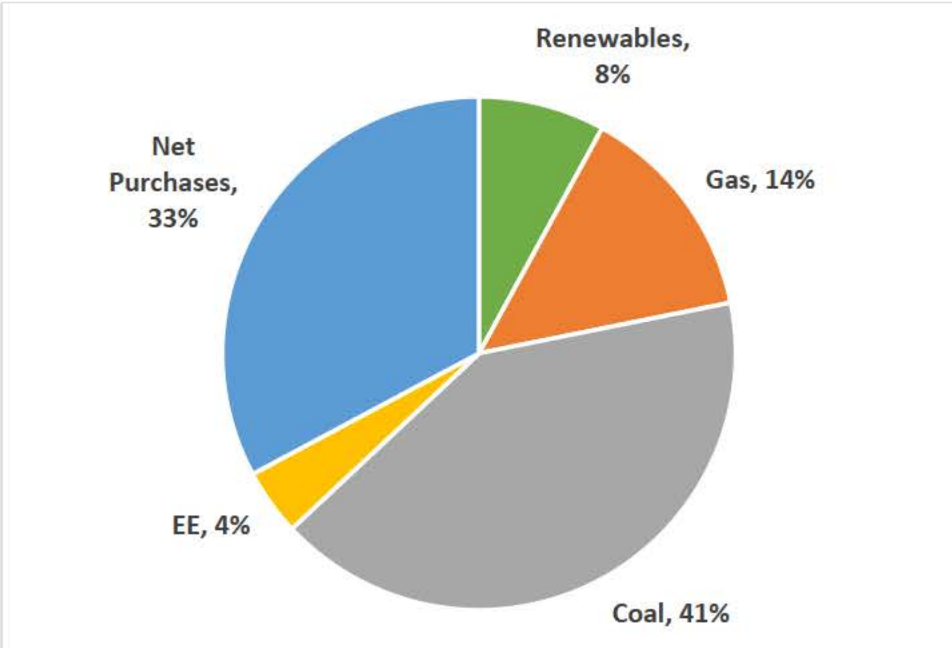


***Table 21. Duke's 2018 IRP Action Plan*[66]**

	RETIREMENTS	ADDITIONS	INCREMENTAL DSM MW
2018			27
2019		Storage (10 MW)	66
2020		Storage (5 MW)	124
2021		CHP (16 MW)	169
2022			213
2023	Gallagher 2 & 4 (280 MW)	Solar (100 MW); CHP (16 MW)	262
2024		Solar (150 MW); Wind (100 MW)	280
2025		Solar (150 MW); Wind (100 MW)	311
2026	Gibson 4 (622 MW)	Solar (150 MW); Wind (100 MW); CHP (16 MW)	330
2027		Solar (150 MW); Wind (100 MW)	357
2028	Cayuga 1-4 (1085 MW); Benton County PPA (100 MW)	Solar (100 MW); Wind (100 MW); CC (1240 MW)	370
2029		Solar (100 MW); Wind (100 MW)	382
2030		Solar (100 MW); Wind (100 MW)	381
2031		Solar (100 MW); Wind (100 MW)	379
2032		Solar (100 MW); Wind (100 MW)	387
2033		Solar (100 MW); Wind (100 MW)	396
2034	Gibson 3 &5; Noblesville CC (1204 MW)	Solar (100 MW); Wind (100 MW); CC (1240 MW)	392
2035		Solar (100 MW); Wind (100 MW)	383
2036		Solar (100 MW); Wind (100 MW)	378
2037		Solar (100 MW); Wind (100 MW)	380
TOTAL	3201 MW		

NOTE: All MW values are nameplate

Duke states, in its IRP, that it would like to work on improving its IRP analysis by adopting new models and improving capital cost forecasts for supply-side resources.[67] While we reiterate that we think those changes should have been made for this IRP, we hope that Duke *meaningfully* engages with stakeholders to *implement* these important changes well before the next IRP gets underway, and does not just hold a series of meetings and calls where no actions are taken and stakeholder concerns are not actually or meaningfully addressed.

[66] Duke Energy Indiana 2018 IRP, p. 20, Table I.1.
[67] Duke Energy Indiana 2018 IRP, p. 98.

APPENDIX 1
CONFIDENTIAL

[redacted]

CONFIDENTIAL - EXCLUDED FROM PUBLIC ACCESS PER A.R. 9(G)

[redacted]

CONFIDENTIAL - EXCLUDED FROM PUBLIC ACCESS PER A.R. 9(G)

[redacted]

CONFIDENTIAL - EXCLUDED FROM PUBLIC ACCESS PER A.R. 9(G)

[redacted]

APPENDIX 2

MOTT MACDONALD

Technical Note

Project:	Duke Energy Indiana IRP Review		
Prepared by:	J.Berkow	**Date:**	11/26/2019
Subject:	Review of Proposed Transmission Upgrades		

1 Introduction

Mott MacDonald LLC (Mott) has been requested by Citizens Action Coalition of Indiana, Inc. (CAC) to review technical documentation related to Indiana Utility Regulatory Commission (IURC) Cause No. 45174, the 2018 Integrated Resource Plan (IRP) from Duke Energy Indiana (Duke). As part of its review, Mott and CAC executed a Confidentiality Agreement with Duke. Mott's review was focused on assessing the reasonableness of the assumptions and conclusions in the portions of the IRP related to generator retirements. Mott's review was limited to technical assumptions and only addresses regulatory or economic considerations to the extent they impact technical assumptions.

2 Documents Reviewed

Mott received and reviewed the following documents:

- 2018 Integrated Resource Plan Volume 1 (IRP),
- Informal Information Request Set 8, CAC 8.5,
- Supplemental Response 7-5-19 to CAC 8.5,
- 2nd Supplemental Response 10-14-19 to CAC 8.5,
- Confidential Attachment CAC 8.5-A,
- Confidential Attachment CAC 8.5-B,
- Confidential Attachment CAC 8.5-C,
- Confidential Attachment CAC 8.5-D, and
- Confidential Attachment CAC 8.5-E.

3 Analysis

3.1 Integrated Resource Plan

Mott acquired the redacted version of the IRP from the public docket information from the IURC. Mott notes that pre-2024 retirements were not permitted due to transmission upgrades and *"regulatory filings and design, permitting, and construction of replacement resources."* Mott notes that a unit can be taken offline prior to being officially retired as long technical requirements are met. Specific technical requirements would include replacement power from existing sources elsewhere on the transmission system (partially addressed in CAC 8.5), lack of transmission upgrades (addressed in CAC 8.5), and evaluating capacity / resource adequacy shortfalls (to be addressed through MISO Optional Studies).

3.2 2016 / 2017 Transmission Retirement Studies

Mott was initially provided with Supplemental Response 7-5-19, CAC 8.5-A, and CAC 8.5-B. Mott had concerns regarding both the assumptions made by Duke and regarding the lack of detail on the results.

CAC 8.5-B outlines the assumptions Duke used for its 2016 Transmission Retirement Study. Specific assumptions which were of concern to Mott were:

- "Generation retirements were replaced with imports from TVA, essentially assuming area interchange control was disabled"
  - Mott notes that Duke does not address whether there are any engineering or regulatory hurdles to importing power into MISO from Tennessee Valley Authority (TVA) and, if so, what steps would be needed to clear such hurdles. As such, Mott is unable to determine whether the assumption of imports from TVA is reasonable.
  - Mott questions whether assuming interchange control to be disabled is a reasonable assumption as this would integrate TVA into MISO.
  - Mott notes that power flow results are highly sensitive to which generation resources are dispatched and where the slack bus is located. Very different results could be achieved if additional generation was sourced throughout the MISO footprint, sourced from specific areas, or sourced from specific generators.
- Mott notes that the retirements were studied using 2021 and 2026 transmission cases, rather than the retirement dates listed in CAC 8.5-A. CAC 8.5-E also identifies 2021 and 2026 transmission cases.
- Mott notes that no source was identified for upgrade costs.
- These scenarios were analyzed in 2016. The electric power grid is in a period of rapid transformation compared with prior decades. Mott recommends that a more up-to-date analysis using both the MTEP and some forward-looking trends be included in the IRP.

CAC 8.5-A outlines the conclusions of Duke's 2016 Transmission Retirement Study. Mott has the following concerns about the conclusions:

- Mott notes that no source was identified for upgrade costs.
- Mott notes that no detailed analysis was provided for verification of upgrade requirements.
- Mott notes that retirements were studied using 2021 and 2026 cases (per CAC 8.5-B) rather than the retirement dates identified in CAC 8.5-A. CAC 8.5-E also identifies 2021 and 2026 transmission cases.
- Cayuga Unit 2 and Noblesville Units 1 & 2 were identified as available for retirement in 2021 with no additional transmission upgrade costs.
  - Mott recommends that deactivation in 2021 be considered part of the economic analysis for the IRP and be submitted to MISO for an Optional Study.
- Gibson Units 1 and 5 were identified as available for retirement in 2026 with no additional transmission upgrade costs.
  - Mott recommends that retirement in 2026 be considered part of the economic analysis for the IRP and be submitted to MISO for an Optional Study.

- Mott recommends that Duke evaluate non-wire alternatives in place of proposed reconductoring projects.

3.3 2019 Transmission Retirement Studies

Following an initial review, Mott was subsequently supplied with Supplemental Response 10-14-19, CAC 8.5-C, CAC 8.5-D, and CAC 8.5-E. Mott had concerns regarding both the assumptions made by Duke and the results.

CAC 8.5-D outlines the assumptions Duke used for its 2019 Transmission Retirement Study. Specific assumptions which were of concern to Mott were:

- "Generation retirements were replaced with imports from TVA, essentially assuming area interchange control was disabled".
  - Mott notes that Duke does not address whether there are any engineering or regulatory hurdles to importing power into MISO from TVA and, if so, what steps would be needed to clear such hurdles. As such, Mott is unable to determine whether the assumption of imports from TVA is reasonable.
  - Mott questions whether assuming interchange control to be disabled is a reasonable assumption as this would integrate TVA into MISO.
  - Mott notes that power flow results are highly sensitive to which generation resources are dispatched and where the slack bus is located. Very different results could be achieved if additional generation was sourced throughout the MISO footprint, sourced from specific areas, or sourced from specific generators.
- Mott notes that the retirements were studied using 2023 transmission cases, rather than the retirement dates listed in CAC 8.5-C. CAC 8.5-E also identifies 2023 transmission cases.
- Mott notes that no source was identified for upgrade costs.

CAC 8.5-C outlines the conclusions of Duke's 2019 Transmission Retirement Study. Mott has the following concerns about the conclusions:

- Mott notes that no source was identified for upgrade costs.
- Mott notes that the retirements were studied using 2023 transmission cases per CAC 8.5-D, rather than the retirement dates listed in CAC 8.5-C. CAC 8.5-E also identifies 2023 transmission cases.
- Noblesville Units 1, 2, 3, 4, and 5 were identified as available for retirement in 2023 with no additional transmission upgrade costs.
  - Mott recommends that deactivation in 2023 be considered part of the economic analysis for the IRP and be submitted to MISO for an Optional Study.
  - Mott notes that Noblesville Units 1 and 2 were analyzed in CAC 8.5-A as retired in 2021 with no upgrades. Mott recommends Duke evaluate if that is still the case, and if not, if it could be accommodated via a Remedial Action Scheme (RAS) as defined in the Glossary of Terms Used in NERC Reliability Standards published by the North American Electric Reliability Council (NERC). If this can be accommodated with or without RAS, Mott recommends that deactivation in 2021 be considered part of the economic analysis for the IRP and be submitted to MISO for an Optional Study.
- Gibson Units 1, 2, and 5 were identified as available for retirement in 2023 with no additional transmission upgrade costs.
  - Mott recommends that deactivation in 2023 be considered part of the economic analysis for the IRP and be submitted to MISO for an Optional Study.
- Mott recommends that Duke evaluate non-wire alternatives in place of proposed reconductoring projects.

4 Conclusions

Mott has reviewed the Transmission Retirement Studies provided by Duke as part of its IRP. These studies analyze various generation retirement scenarios and the required transmission upgrades. Mott has the following concerns and recommendations regarding the studies:

- Concerns:
  - Mott notes that Duke does not address whether there are any engineering or regulatory hurdles to importing power into MISO from TVA and, if so, what steps would be needed to clear such hurdles. As such, Mott is unable to determine whether the assumption of imports from TVA is reasonable.
  - Mott questions whether assuming interchange control to be disabled is a reasonable assumption.
  - Mott requests Duke provide a source for cost information.
- Recommendations
  - Mott recommends Duke perform supplemental analysis on the deactivation by 2021 of Noblesville 1 and 2. If it can be accommodated without transmission upgrades or via a Remedial Action Scheme for the 2021 – 2023 time period, the Mott recommends it be part of the economic analysis in the IRP and that the required studies be initiated with MISO.
  - Mott recommends deactivation of Noblesville 1, 2, 3, 4, and 5 by 2023 be part of the economic analysis in the IRP and that the required studies be initiated with MISO.
  - Mott recommends deactivation of Gibson Units 1, 2, and 5 by 2023 be part of the economic analysis in the IRP and that the required studies be initiated with MISO.
  - Mott recommends that Duke evaluate non-wires alternatives for any transmission line reconductoring recommended as part of the retirement studies.