STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, LLC ("DUKE ENERGY INDIANA") PURSUANT TO IND. CODE CHS. 8-1-8.5, 8-1-8.8, AND IND. CODE §§ 8-1-2-0.6 AND 8-1-2-23 FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") PURSUANT TO IND. CODE CH. 8-1-8.5 TO CONSTRUCT TWO COMBINED CYCLE ("CC") NATURAL GAS UNITS, AT APPROXIMATELY 738 MEGAWATTS (WINTER RATING) EACH, AT THE EXISTING CAYUGA GENERATING STATION ("CAYUGA CC PROJECT"); (2) APPROVAL OF THE CAYUGA CC PROJECT AS A CLEAN ENERGY PROJECT AND AUTHORIZATION FOR FINANCIAL INCENTIVES INCLUDING TIMELY COST RECOVERY THROUGH CONSTRUCTION WORK IN PROGRESS ("CWIP") RATEMAKING THROUGH A GENERATION COST ADJUSTMENT ("GCA") TRACKER MECHANISM UNDER IND. CODE CH. 8-1-8.8; (3) AUTHORITY TO RECOVER COSTS INCURRED IN CONNECTION WITH THE CAYUGA CC PROJECT; (4) APPROVAL OF THE BEST ESTIMATE OF COSTS OF CONSTRUCTION ASSOCIATED WITH THE CAYUGA CC PROJECT; (5) APPROVAL OF CHANGES TO DUKE ENERGY INDIANA'S ELECTRIC SERVICE TARIFF RELATING TO THE PROPOSED GCA TRACKER MECHANISM; (6) APPROVAL OF SPECIFIC RATEMAKING AND ACCOUNTING TREATMENT; AND (7) ONGOING REVIEW OF THE CAYUGA CC PROJECT	)	**CAUSE NO. 46193**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
PUBLIC'S EXHIBIT NO. 3
TESTIMONY OF OUCC WITNESS
JOHN W. HANKS

Respectfully submitted,

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

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T. Jason Haas, Attorney No. 34983-29
Senior Deputy Consumer Counselor
Adam Kashin, Attorney No. 37960-49
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS JOHN W. HANKS
CAUSE NO. 46193
DUKE ENERGY INDIANA, LLC

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is John W. Hanks, and my business address is 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed as a Utility Analyst in the Indiana Office of Utility Consumer Counselor's ("OUCC") Electric Division. A summary of my educational background and experience is provided in Appendix A attached to my testimony.

Q: What is the purpose of your testimony?

A: I recommend the Commission deny Duke Energy Indiana, LLC's ("Duke" or "Petitioner" or the "Company") petition for a Certificate of Public Convenience and Necessity ("CPCN") for its proposed Cayuga Combined Cycle Project ("Cayuga CC Project"). This is due to recent, material regulatory developments and the availability of less capital-intensive alternative resource options. Duke's 2024 Integrated Resource Plan ("IRP") shows there are viable, less capital-intensive alternatives to the proposed Cayuga CC Project. I discuss recent regulatory developments related to the U.S. Environmental Protection Agency's ("EPA") Clean Air Act ("CAA") Section 111 Rule, which should lead to reconsideration of Duke's preferred portfolio. I also discuss the IRP's High Capital Cost sensitivity test, which evaluated resource strategies under conditions of high capital costs for combined cycle ("CC") and combustion turbines ("CT").

Q: Please describe the review and analysis you conducted to prepare your testimony.

A: I reviewed Duke's case-in-chief and associated attachments. I helped compose data requests and reviewed the responses. I also reviewed Duke's 2024 IRP and participated throughout Duke's public stakeholder process during the compilation of the IRP. Additionally, I contributed to and helped revise the comments the OUCC provided to Dr. Bradley Borum, Director of the Indiana Utility Regulatory Commission's ("Commission") Research, Policy, and Planning Division, regarding Duke's 2024 IRP.

Q: To the extent you do not address a specific topic, issue, or item, does this mean you agree with those portions of Duke's proposals?

A: No. My silence regarding any specific topic, issue, or item Duke proposes does not indicate my approval of those matters. Rather, the scope of my testimony is limited to the specific items I address.

II. CPCN AND IRP BACKGROUND

Q: Describe your understanding of Duke's IRP as it relates to this proceeding.

A: Investor-owned Indiana electric utilities, among others, must periodically submit IRPs in order to assess the resources that can be used to meet customer service needs. Ind. Code § 8-1-8.5-3(e) states:

> In addition to such reports as public utilities may be required by statute or rule of the commission to file with the commission, a utility:
>
> 1) may submit to the commission a current or updated integrated resource plan as part of a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility; and
> 2) shall submit to the commission an integrated resource plan that assesses a variety of demand side management and supply side

> resources to meet future customer electricity service needs in a cost effective and reliable manner.

In relation to CPCN proceedings, Ind. Code § 8-1-8.5-5(d) states:

> The commission shall consider and approve, in whole or in part, or disapprove a utility specific proposal or an amendment thereto jointly with an application for a certificate under this chapter. However, such an approval or disapproval shall be solely for the purpose of acting upon the pending certificate for the construction, purchase, or lease of a facility for the generation of electricity.

Thus, the Commission shall consider and approve, in whole or in part, a utility's IRP solely for the purpose of acting on an application for a CPCN. Unlike some states, Indiana's IRPs are not developed through formal Commission dockets and the resource plans derived from IRPs are not binding. Duke's IRP models various strategies with distinct resource portfolios; however, the preferred portfolio that determines the resource decisions included in Petitioner's short-term action plan is selected by Duke, not the Commission or stakeholders. When a CPCN is requested, pursuant to the statute, the Commission must consider whether the proposed project is consistent with the Company's IRP.[1] The Commission may disapprove a utility's request for a CPCN under Ind. Code § 8-1-8.5-5(d) even if the request is "consistent" with its IRP. For instance, in Cause 45052, the Commission found that Vectren South's request was "consistent" with its 2016 IRP but still ended up rejecting the utility's request for a CPCN.[2]

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[1] Ind. Code § 8-1-8.5-5(b)(2).

[2] *In Re Southern Ind. Gas & Elec. Co.*, Cause No. 45052, Final Order p. 26, Ordering Paragraph 1 (Ind. Util. Regul. Comm'n April 24, 2019).

IRPs contain analyses relevant to CPCN proceedings under Ind. Code § 8-1-8.5-4(b), which states:

> (b) In acting upon any petition for the construction, purchase, or lease of any facility for the generation of electricity, the commission shall take into account the following:
>
> (1) The applicant's current and potential arrangement with other electric utilities for:
> (A) the interchange of power;
> (B) the pooling of facilities;
> (C) the purchase of power; and
> (D) joint ownership of facilities.
>
> (2) Other methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources.
>
> (3) With respect to a petition that:
> (A) is for the construction of a new generating facility; and
> (B) is submitted to the commission after June 30, 2021, and before January 1, 2025;
> the impact of federal phaseout mandates on the estimated useful life of each proposed generating facility included in the petition, including depreciation expense associated with each facility.
>
> (4) With respect to a petition that is submitted to the commission after June 30, 2023, whether the proposed construction, purchase, or lease of the facility will result in the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:
> (A) reliability;
> (B) affordability;
> (C) resiliency;
> (D) stability; and
> (E) environmental sustainability;
> as described in IC 8-1-2-0.6.

Q: Do you agree with Duke Witness Nathan Gagnon that Ind. Code § 8-1-8.5-2.1 does not apply to this proceeding?

A: No. Under Ind. Code 8-1-8.5-2.1(b), a public utility must notify the Commission if:

> (1) the public utility intends or decides to retire, sell, or transfer an electric generation facility with a capacity of at least eighty (80) megawatts; and
> (2) the retirement, sale, or transfer:
>
> (A) was not set forth in; or
>
> (B) is to take place on a date earlier than the date specified in; the public utility's short term action plan in the public utility's most recently filed integrated resource plan.

Under Ind. Code § 8-1-8.5-2.1(d), unless the public utility's proposal for the retirement of an electric generating facility is consistent with the public utility's short-term action plan:

> the commission shall not permit the public utility's depreciation rates, as established under IC 8-1-2-19, to be amended to reflect the accelerated date for the retirement, sale, or transfer of the electric generation asset unless the commission finds that such an adjustment is necessary to ensure the ability of the public utility to provide reliable service to its customers, and that the unamended depreciation rates would cause an unjust and unreasonable impact on the public utility and its ratepayers.[3]

Duke Witness Nathan Gagnon states the Cayuga coal-unit retirements were included in the Company's most recently submitted IRP.[4] Duke's most recent IRP was, however, submitted to IURC staff shortly before Duke initiated this proceeding. This is relevant because the Cayuga coal unit retirement dates changed within Duke's short-term action plan between the 2021 and 2024 IRPs.[5] The 2021 IRP showed retirement dates for Cayuga Units 1 and 2 in 2026; further, in Duke 2023's IRP refresh, which updated the expansion modeling with fresh assumptions, the units were slated for retirement in 2027 as part of the preferred portfolio.[6] The

[3] Ind. Code 8-1-8.5-2.1(d).
[4] Petitioner's Exhibit 6, Direct Testimony of Nathan Gagnon, page 23, lines 7-10.
[5] Duke 2021 IRP, page 26 and Duke 2024 IRP, page 10.
[6] 2024 Duke Energy Indiana IRP Stakeholder Meeting 3 on June 20, 2024, page 25.

optimal time to economically retire the Cayuga units within Duke's preferred resources portfolios has changed. The latest iteration, filed on November 1, 2024, was finalized after Cayuga CC Project preparations were likely underway and just before the federal and state November 2024 elections in the United States. It does not incorporate the policies of these new administrations or their impacts, including Executive Order 25-50, signed by Governor Braun on April 10, 2025. This Executive Order explicitly calls for the re-evaluation of coal unit retirements, partially because Indiana has fallen from having the fourth lowest electricity cost in the nation to the 28th lowest cost of electricity.[7] Duke's 2024 IRP shouldn't be the only reference point for the Commission's consideration when this CPCN case was likely being prepared while the previous IRP was in effect. Furthermore, because the Commission does not approve a utility's short-term action plan when the IRP is submitted, that short-term action plan, and its selection when there are viable alternatives, should be evaluated as part of a CPCN. Ind. Code § 8-1-8.5-2.1 specifically states that the retirement of an asset should be considered in light of ratepayer impact, which is crucial in this proceeding.

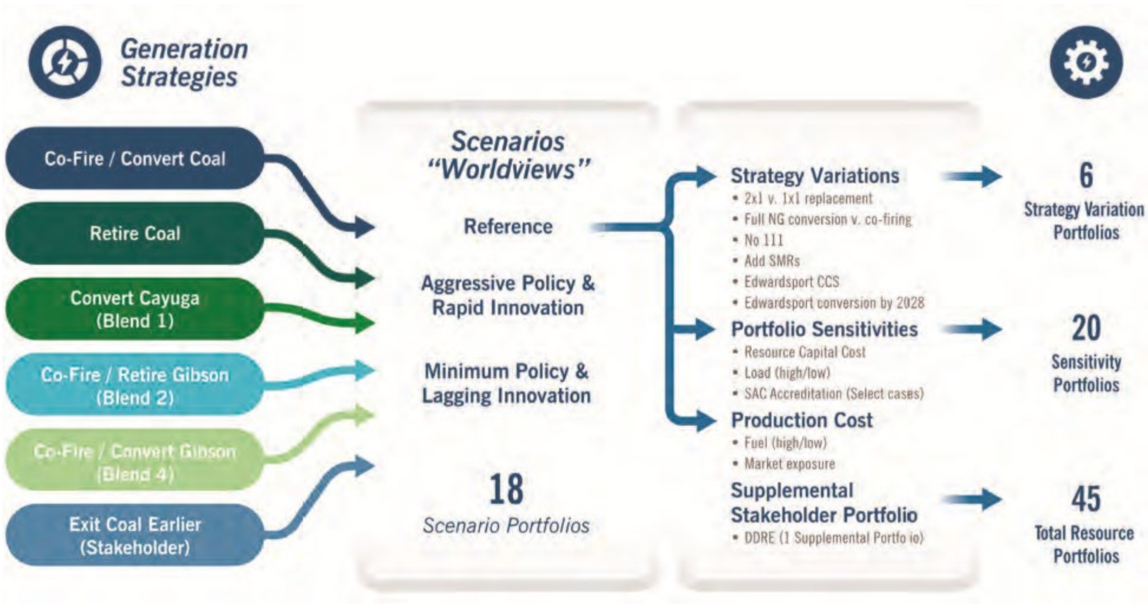
III. DUKE'S 2024 IRP ANALYSIS

Q: Describe Duke's analysis of potential resource plans in its 2024 IRP.

[7] Executive Order 25-50, signed on April 10, 2025, found at: https://www.in.gov/gov/files/EO-25-50-.pdf.

A: Duke evaluated 45 distinct resource plans, or resource portfolios, which are noted in the table below: [8]

Figure 2-9: 2024 IRP Analytical Framework

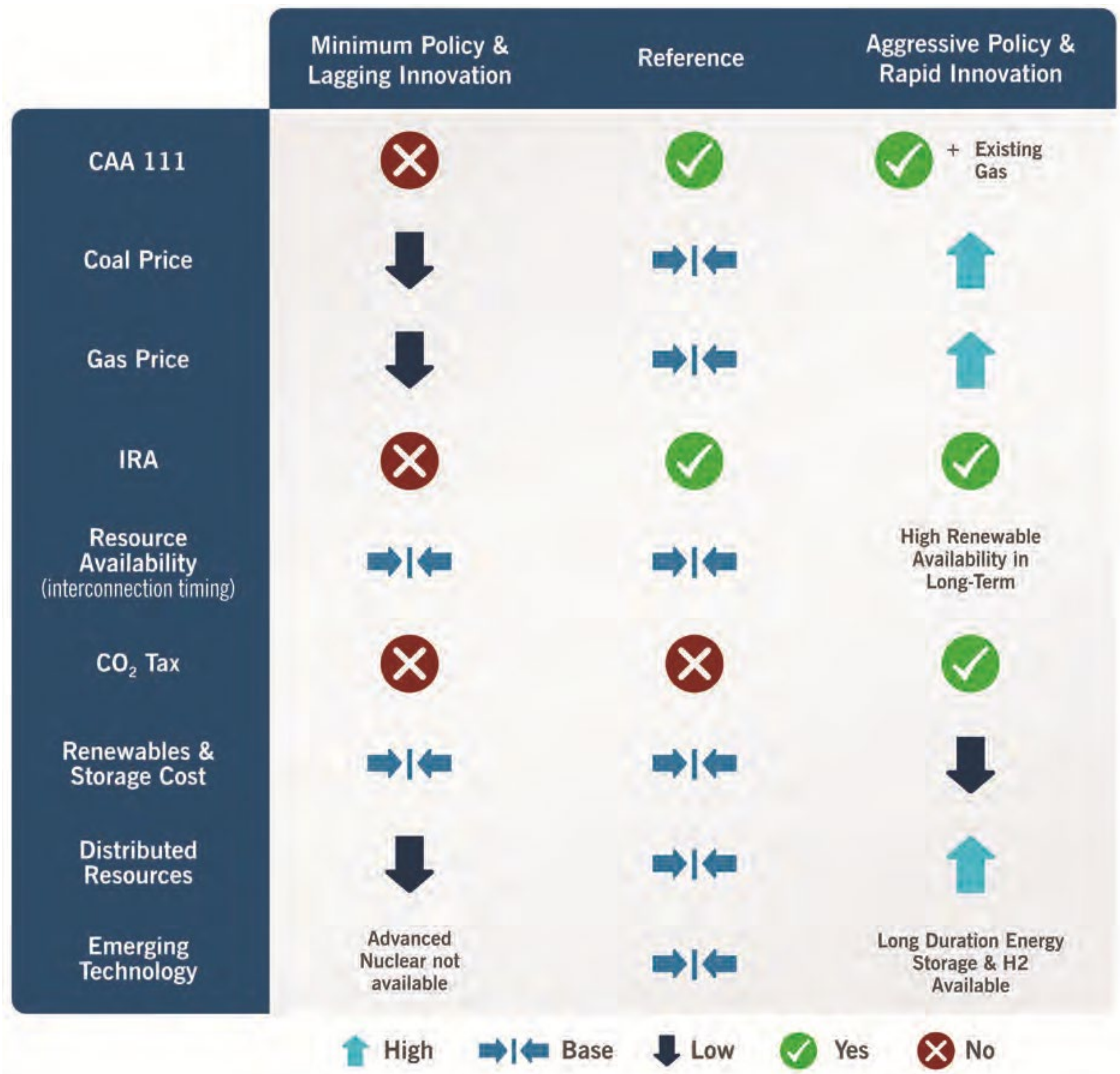


The left half of the figure represents the six generation strategies where each is evaluated under three scenarios. The six generation strategies were designed to evaluate the different pathways to comply with the EPA CAA Section 111 Rule ("EPA 111 Rule").[9] The three scenarios reflect possible future states of the utility's operating environment and show the impact of external trends on key variables in the resource plan. The three scenarios Duke included are represented in the table

[8] Gagnon Direct, Attachment 6-A, 2024 Duke Energy Integrated Resource Plan, page 56.
[9] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 52.

below, as well as some of the assumptions that are different between each scenario:[10]

Figure 2-6: Summary of Assumptions by Scenario



The six generation strategies were evaluated under the three scenarios, leading to 18 resource portfolios. The right half of Figure 2-9 above shows these 18 resource portfolios were adjusted in response to sensitivity tests and strategy variations

[10] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 51.

reflecting differences such as selectable technology configurations like a 2x1 CC unit or circumstances with high capital costs for CC units.

Q: Describe your analysis of the different scenarios included in Duke's 2024 IRP as it relates to this proceeding.

A: IRPs model ranges of possible futures meant to create resource plans that can flexibly respond to uncertain future changes in the utility's operating circumstances. This is affirmed in Duke's 2024 IRP, which states, "Importantly, the Company is pursuing a path in its short-term action plan that has low or no regrets, with the ability to make adjustments if circumstances warrant."[11] Some of these circumstances may be unknown when the IRP is being prepared, for example, a technological breakthrough that occurs after the utility submits its IRP to the Commission. However, some uncertain conditions can be anticipated and evaluated, such as the potential repeal of an environmental rule like EPA Rule 111, which Duke ostensibly evaluated in its "Minimum Policy and Lagging Innovation" scenario and the "No 111" generation strategy. The Company's No 111 strategy analysis found that if EPA Rule 111 is repealed, the resulting resource portfolio has an annual revenue requirement of $23.2 Billion,[12] which is $1.1 Billion lower than the Company's preferred portfolio.[13] These potential savings make it incumbent on Duke to adjust its short-term plan and preferred portfolio in order to realize these savings.

[11] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 15.
[12] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 128.
[13] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 122.

The advantage of modeling resource selection under a range of scenarios is that if the utility's operating environment ends up resembling one scenario rather than another, the utility's resource portfolio and short-term action plan can be adjusted in light of the circumstances modeled in one scenario rather than the utility's initial preference. Duke's preferred portfolio resource plan was based on a particular forecasted state of affairs, the reference case. I recommend Duke's chosen preferred portfolio and short-term action plan be re-evaluated in light of recent regulatory developments and significant capital cost increases.

Also, Duke has insufficiently supported its selection of Blend 2, one of the generation strategies listed above that includes retiring the Cayuga Units in 2030 and 2031, over other resource plans that were evaluated. The OUCC raised this concern in its comments on Duke's 2024 IRP.[14]

Q: Does Duke's short-term action plan call for other items that should be re-evaluated in light of changed circumstances?

A: Yes. Duke will *not* be seeking *only* one CPCN for 1,438 MWs of CCs before its next IRP is filed in November 2027. Duke's short-term action plan includes the CCs to replace Cayuga Units 1 and 2 (the Cayuga CC Project), as well as "2025–2026: File CPCN for Gibson 2x1 CC at 1,438 MW to be in-service BOY (beginning of year) 2032, submit air permits, submit MISO [Generator Replacement Requests] for Gibson units 3 and 4."[15] This means that prior to Duke's next IRP, Duke intends to propose to construct CCs of similar size and cost to the Cayuga CC Project. This

[14] Attachment JWH-1, Indiana Office of Utility Consumer Counselor's Comments on Duke Energy Indiana's 2024 IRP, pages 2-3.
[15] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 168.

makes re-evaluation and modification of Duke's short-term action plan even more important due to the high costs for ratepayers to fund these large capital projects.

IV. DUKE'S 2024 IRP RESOURCE PORTFOLIOS AND SCENARIO COMPARISON

Q: Please describe the results of the IRP's evaluation of the resource portfolios that include natural gas conversion for Cayuga Units 1 and 2, in comparison to the portfolio that includes retirement of the Cayuga Units and replacement by CCs as proposed in this proceeding.

A: The results of the six generation strategies under the referenced scenario are shown in the IRP's scorecard below:[16]

Table 4-2: Summary of Portfolio Scorecard Results

Portfolio Scorecard

			Convert/Co-Fire Coal	Retire Coal	Blend 1	Blend 2	Blend 4	Exit Coal Earlier (Stakeholder)
Environmental Sustainability	CO_2 Emissions Reduction	2035	74%	73%	70%	72%	74%	72%
		2044	91%	81%	81%	84%	88%	86%
	Cumulative CO_2 Reduction (Mt)	2044	367	340	337	348	367	362
	CO_2 Intensity of Duke Energy Indiana Portfolio (lbs./MWh)	2035	715	572	710	678	666	652
Affordability	PVRR ($B)	2044	$25.0	$23.6	$24.2	$24.3	$24.5	$24.3
	Customer Bill Impact (CAGR)	2030	3.9%	3.7%	3.9%	4.0%	4.0%	4.3%
		2035	3.1%	3.3%	2.8%	3.1%	2.9%	3.1%
Reliability	Fast Start Capability	2035	39%	31%	33%	33%	33%	38%
	Spinning Reserve Capability	2035	93%	93%	98%	102%	100%	87%
Resiliency	Resource Diversity (HHI)	2035	1766	3853	2802	2739	1758	2291
	Simulated EUE in 95th Percentile Cold Weather (Islanded System)	2035	2.8%	1.9%	0.9%	1.4%	2.1%	3.7%
Cost Risk	Cost Variability Across Scenarios ($B)	2044	$24.0-$28.1	$21.8-$26.8	$22.4-$27.2	$22.9-$26.9	$23.3-$27.8	$23.4-$27.2
	IRA Exposure	2030	81%	43%	81%	50%	49%	57%
		2035	81%	29%	20%	22%	33%	39%
Market Exposure	Fuel Market Exposure	Average	61%	72%	76%	72%	66%	70%
	Maximum Energy Market Exposure	Annual Max.	69%	43%	51%	53%	66%	52%
Execution Risk	Cumulative Resource Additions in MW	2030	1,037	1,656	1,037	1,856	1,831	2,181
		2035	1,823	5,568	4,049	4,149	2,686	4,105
	Cumulative Resource Additions as % of Current System	2030	13%	20%	13%	23%	23%	27%
		2035	22%	69%	50%	51%	33%	51%

Note that the scorecard shows these generation strategies under the reference case, as opposed to the "Minimum Policy & Lagging Innovation" or "Aggressive Policy & Rapid Innovation" scenarios. Blend 1 is Duke's generation strategy that includes the conversion of Cayuga Units 1 and 2, as well as Edwardsport, from coal to natural gas in 2030. Blend 2 is Duke's preferred portfolio and includes retirement of the existing Cayuga coal and replacement by gas CCs. Notably, the Blend 1 strategy is cheaper, as it has a lower present value revenue requirement as well as a lower customer bill impact than the Duke-selected resource portfolio, Blend 2. IRPs are frequently updated and new IRPs are submitted every three years. As resource additions that take place longer than three years from now will be evaluated in future IRP editions, the differences between resource plans for the near term are crucial. It is important to note that by 2030, Blend 1 includes significantly fewer resource additions, which the scorecard describes as execution risk. The scorecard does identify "IRA [Inflation Reduction Act] Exposure" as one category in which Blend 1 scores are worse than the preferred portfolio Blend 2, which in 2030 is 80% IRA exposure for Blend 1 and 50% IRA exposure for Blend 2. However, this comparison is less important due to the regulatory developments Ms. Armstrong discusses. When comparing Blend 1 and the preferred Blend 2, apart from IRA exposure, there do not seem to be significant differences between the two

[16] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 130.

portfolios except that Blend 1, which converts the Cayuga units to natural gas, entails lower costs for customers and fewer resource additions prior to 2030.

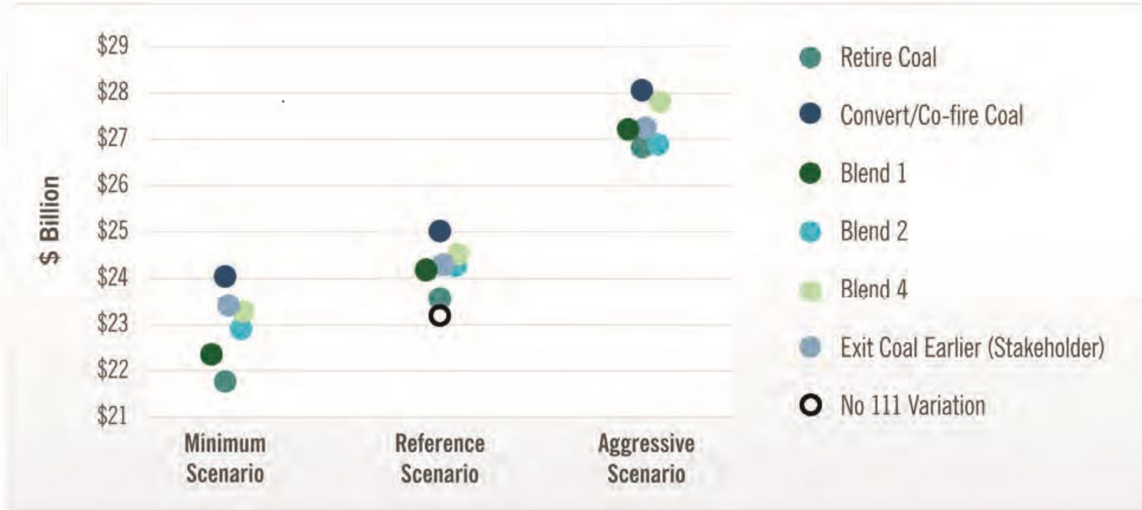
Q: Within Duke's 2024 IRP, what other scenarios associated with different futures did you conclude better reflect the utility's operating environment, and how does this relate to the discussion of the preferred resource portfolio?

A: The current regulatory environment is more consistent with the "Minimum Policy & Lagging Innovation" scenario, which relaxes EPA Rule 111 requirements. This is significant when developing a resource plan or short-term action plan based on the results of Duke's 2024 IRP because, as the Company states, "[present value revenue requirement] results diverge most in the Minimum Scenario, which contemplates relaxed regulatory restrictions. With more flexibility, the total cost of each generation strategy is lower in the Minimum Scenario than in the Reference Scenario."[17] If the Minimum Policy scenario better reflects the current regulatory climate, then it becomes more problematic that Duke did not justify its selection of Blend 2.

This greater variability of PVRR results is shown in the following figure:[18]

Figure 4-7: Present Value Revenue Requirement ("PVRR") by Generation Strategy Including "No 111" Strategy Variation

[17] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 113.
[18] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 114.



It is notable that in the Minimum Scenario, the difference between the PVRRs of Blend 1 and Blend 2 is even greater than in the Reference Scenario. Blend 1 has an associated PVRR of $22.3 Billion which is approximately $600 Million less expensive than Blend 2, which has a PVRR of $22.9 Billion. In brief, Blend 1, which includes the Cayuga units converting to natural gas, will be less costly to ratepayers in both the Reference Scenario and, especially, the Minimum Policy scenario. Duke has not established that its preferred portfolio, which includes retiring the Cayuga coal units to be replaced by new gas CCs, is in the best financial interest of its customers, particularly given the regulatory changes not adequately reflected in its preferred portfolio.

Q: As is included in Blend 1, why did the Company exclude from its preferred portfolio the conversion of the Cayuga units to natural gas fuel?

A: Within its testimony, the Company did not discuss why Blend 1 was rejected. Mr. Gagnon does argue that replacing the Cayuga steam units with new CCs is a lower cost and lower risk option for customers.[19] Mr. Gagnon argues that conversion to

[19] Gagnon Direct, page 13, lines 14-16.

natural gas is not in the customers' best interests through a comparison of the PVRR results of the Convert/Co-fire Coal strategy and the Blend 4 strategy. He states:

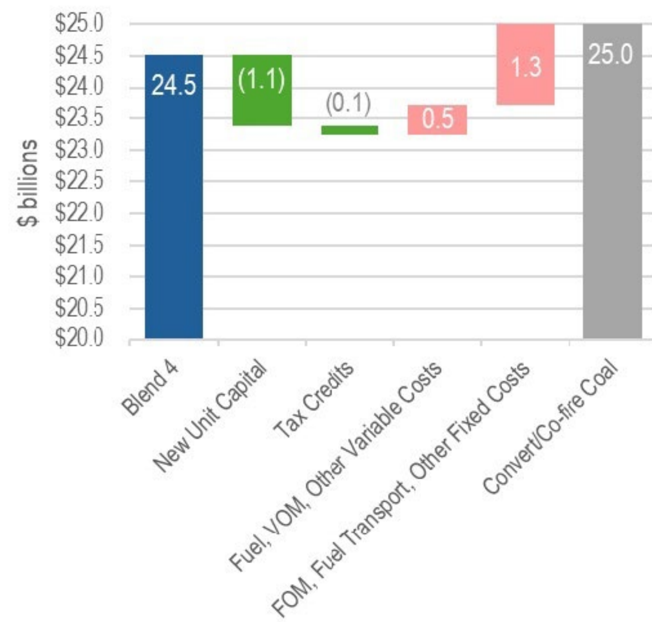
> The difference between the two strategies is the pathway at Cayuga. Under the Convert/Co-fire Coal strategy, the existing coal-fired Cayuga steam units are converted to natural gas fuel. As previously explained, under the Blend 4 pathway, the Cayuga units are retired and replaced with two 1x1 combined cycle units. The present value of revenue requirements ("PVRR") for the Convert/Co fire Coal strategy, which includes gas conversion of the Cayuga coal-fired units, is approximately $500 Million greater than the PVRR for Blend 4, in which the Cayuga coal-fired units are retired.[20]

It is worth noting that Mr. Gagnon does not discuss Blend 1 - also called the "Convert Cayuga" blend - which has a lower PVRR than the preferred portfolio by approximately $100 Million per year.[21] Instead, he compares the Company's

[20] Gagnon Direct, page 15, lines 1-7.
[21] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 120.

Convert/Co-Fire coal strategy to Blend 4, the "Co-fire/Convert Gibson" blend. The cost differences described by Mr. Gagnon are as follows:[22]

Figure 5: PVRR Comparison of Blend 4 to Convert/Co-fire Coal



Notice that Blend 4 has $1.1 Billion greater capital costs than the Convert/Co-fire coal strategy. As I discuss later, the costs of a CC included in the IRP for the base scenario are significantly lower than the costs proposed for the Cayuga CC Project in this case. Therefore, Gagnon's capital cost comparison understates the costs of new CCs and makes the retirement of the Cayuga coal units look more attractive. I

[22] Gagnon Direct, p. 16, Figure 5.

also note that Blend 1 includes the conversion of the Cayuga units to natural gas, and it has a lower PVRR than the preferred portfolio.

Q: Did the Company select Blend 2 over Blend 1 because of advantages related to reliability and resiliency?

A: It does not appear so. Based on the scorecard for the various generating strategies, Blend 1 appears to be comparable to Blend 2 on all reliability and resiliency metrics (red lines around Blend 1 and Blend 2 added to Table 4-2):[23]

[23] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 130.

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		2035	1,823	5,568	4,049	4,149	2,686	4,105
	Cumulative Resource Additions as % of Current System	2030	13%	20%	13%	23%	23%	27%
		2035	22%	69%	50%	51%	33%	51%

In reference to the preferred portfolio Blend 2, Blend 1 has comparable Fast Start Capability, Spinning Reserve Capability, Resource Diversity, and lower Expected

Unserved Energy and Customer bill impacts. So, it does not appear that the selection of Blend 2 is driven by reliability or resiliency benefits.

Q: Mr. Gagnon states the pricing modeled in the 2024 IRP is consistent with the cost of the Cayuga CC Project because the Cayuga CCs are "well within the range of costs modeled in the 2024 IRP."[24] Do you agree with this statement?

A: No. The "range of costs modeled in the 2024 IRP" is ambiguous as different costs are modeled for CCs within the IRP depending on the scenario or generation strategy referenced. Mr. Gagnon goes on to the clarify that the Cayuga CC Project was within the range of capital costs used in the Company's "High CC/CT Cost" cost strategy, where the Cayuga CC Project has costs approximately 20% greater than those included in the IRP's reference scenario, and the High CC/CT case included costs 60% greater than the reference case.[25] For 1x1 CCs, Duke's 2024 IRP included capital costs of $1,450-$1,550/kW,[26] and therefore, the High CC cost case included capital costs for 1x1 CCs of $2,320-$2,480/kW. When Mr. Gagnon states the Cayuga CC Project has costs 20% higher than the IRP's base scenario, it is unclear which costs within the best estimate he is including to make this comparison.[27] Mr. Gagnon references Duke Witness John Smith, who states that the total best estimate for the Cayuga CC Project is $3.33 Billion.[28] Using the 1,476 MW winter rating proposed for the Cayuga CC Project,[29] I estimate the overnight capital cost of the Cayuga CC Project to be approximately $2,256/kW.[30] Depending

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[24] Gagnon Direct, page 21, lines 8-10.
[25] Gagnon Direct, page 21, lines 10-13.
[26] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 421.
[27] Gagnon Direct, page 21, lines 8-9.
[28] Petitioner's Exhibit 3, Direct Testimony of John Robert Smith, page 18, lines 20-21.
[29] Smith Direct, page 3, lines 11-14.
[30] $3.33 billion/(1476*1000)

on whether the lower or higher range of 1x1 CCs in the 2024 IRP is used, the Cayuga CC Project is approximately either 46% or 56% more expensive than the reference case, much higher than the 20% increase over the base scenario Mr. Gagnon describes.

Q: How does the High CC Cost sensitivity analysis inform Duke's request for the Cayuga CC Project?

A: In regard to the High CC Cost strategy, Mr. Gagnon states:

> This case assumed costs 60% greater than the base case costs for CCs and combustion turbines (CTs) and, as explained in Chapter 4 of the 2024 IRP, even at this very high cost, Blend 2 still included 1,438 MW of model-selected CC capacity, which is consistent with the capacity of the Cayuga CC Project.[31]

However, this statement raises an important limitation of the High CC sensitivity test. As a strategy variation of Blend 2, the conversion or co-firing of natural gas was not an option selectable by the portfolio optimization modeling.[32] It is possible that conversion to natural gas or co-firing could economically extend the life of the Cayuga Units if these options were included as possibilities in the High CC Cost strategy. Thus, even if the High CC Cost strategy included 1,438 MW, this still does not establish that retiring the Cayuga coal units and replacing them with new CCs is in the best interest of Duke's customers as compared to alternatives like gas conversion or co-firing. Furthermore, in response to an OUCC data request, Duke elaborated on the type of CC selected in the High CC Cost strategy, stating: "The results of capacity expansion modeling for Blend 2 in the 'High CC/CT Cost' included a single 2x1 CC being selected at the beginning of 2032. The capacity of

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[31] Gagnon Direct, page 21, lines 13-15.
[32] Attachment JWH-2, Duke Response to OUCC DR 8.07(a).

the generic 2x1 CC is equal to the combined capacity of two generic 1x1 CCs, consistent with the Cayuga CC Project."[33] It is significant that the High CC Cost strategy included a 2x1 CC rather than two 1x1 CCs, as Duke is proposing in this case. This is significant because in the 2024 IRP, 2x1 CCs were much less expensive with an associated overnight capital cost of $1,100-1,250/kW relative to the 1x1 CC cost of $1,450-$1,550/kW.[34] Thus, the High CC Cost strategy calls for a different, less expensive type of CC than Duke is proposing for Cayuga in this case. Furthermore, the 2x1 CC was added in 2032, rather than starting in 2030, which allows the existing Cayuga coal units to continue operating and delays the addition of new projects with high capital costs.

Q: Please summarize your analysis of Duke's 2024 IRP as it relates to the Cayuga CC Project.

A: Duke has not demonstrated its decision to select Blend 2, which includes the retirement of the existing Cayuga Units 1 and 2 and replacement by CCs starting in 2030, is in the best interest of its customers, promotes affordability, or is in the public interest. Blend 1, which includes the conversion of Cayuga to natural gas, had a modestly lower PVRR than Blend 2 in the reference scenario and a significantly lower PVRR in the Minimum Policy scenario. Rather than the reference scenario, Duke's Minimum Policy scenario, which does not require adherence to EPA Rule 111, better captures the current regulatory environment. The resource plans based on these scenarios that delay coal asset retirement should be pursued. I disagree with Mr. Gagnon that the High CC Cost case established the

[33] Duke Response to OUCC DR 8.07(b).
[34] Gagnon Direct, Attachment 6-A, Duke 2024 IRP, page 421.

need for gas CCs as proposed for the Cayuga CC Project, because this case did not include the option for the conversion to or co-firing of natural gas. I also highlight that the CC selected in the High CC Cost case is a less costly 2x1 configuration, rather than the two 1x1 CCs Duke is proposing.

V. OUCC RECOMMENDATIONS

Q: Please summarize your recommendations to the Commission in this Cause.

A: I support the OUCC's overall recommendation that the Commission deny Duke's request for a CPCN for the Cayuga CC Project as proposed. Duke did not establish that its preferred portfolio, upon which the proposal for the Cayuga CC Project is based, is the best resource strategy for its customers relative to alternative strategies that include natural gas conversion and operating coal units longer. The alternative strategies merit further study and consideration.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A
QUALIFICATIONS OF JOHN W. HANKS

Q: Please describe your background and experience.

A: I graduated from Indiana University-Purdue University Indianapolis with a Bachelor of Arts in Quantitative Economics, with minors in math and philosophy. I began my career with the OUCC in 2022 as a Utility Analyst II, focusing on economics and finance in the Electric Division. In the summer of 2022, I attended the Institute of Public Utilities' Annual program on Regulatory Fundamentals. In the fall of 2022, I participated in the Indiana Energy Conference organized by Indiana Industrial Energy Consumers. In March of 2023, I completed a 12-week course with Scott Hempling on Regulating Utility Performance. In May of 2024, I completed Rate School training through the National Association of Regulatory Utility Commissioners. More recently I have completed work as to IRP modeling DSM modeling, and I have participated, and provided testimony, in Commission docketed cases, including financing cases and base rate cases.

Q: Have you previously filed testimony in other Commission proceedings?

A: Yes.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

John W. Hanks
Utility Analyst II
Indiana Office of Utility Consumer Counselor

Cause No. 46193
Duke Energy Indiana, LLC

Date: May 8, 2025

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR COMMENTS ON DUKE ENERGY INDIANA'S 2024 IRP

FEBRUARY 13, 2024

Introduction

The Indiana Office of Utility Consumer Counselor ("OUCC") respectfully offers these comments regarding Duke Energy Indiana's ("Duke") 2024 Integrated Resource Plan ("IRP"). The importance of IRPs continues to grow in planning a flexible, reliable and cost-effective future for Indiana's electric utility customers. The OUCC's comments include recommended improvements to Duke's IRP Stakeholder Process and its Preferred Portfolio development and suggestions to the Indiana Utility Regulatory Commission's ("IURC") Research, Policy, and Planning Division for the benefit of Indiana's consumers.

The OUCC acknowledges and appreciates the significant time, effort, and resources that Duke, its stakeholders, and IURC staff have expended in developing Duke's IRP. The constructive feedback process used during Duke's IRP Stakeholder meetings and the written comments stakeholders provide upon submitted IRPs are essential to the development of Indiana's energy future. All comments should be considered to improve IRPs.

The fact the OUCC does not address specific items in its IRP comments does not suggest tacit support for such matters. Natural constraints and complexities of IRP exercises limit the ability of stakeholders to address every issue and potential opportunity for improvement.

Regarding Duke's 2024 IRP, the OUCC offers the following specific observations and recommendations:

- The stochastic analysis Duke uses to evaluate portfolio performance across various uncertainties, which includes the Enhanced Reliability Evaluation, is an improvement from the 2021 IRP and should be continued in future IRP analyses.
- Duke's portfolio Scorecard also improved from the 2021 IRP, with a comprehensive evaluation of the Five Pillars of Electric Utility Service ("Five Pillars") as defined in Ind. Code § 8-1-2-0.6.
- Duke should evaluate portfolios with more resource variety wherever possible. There was not enough variation across the portfolios modeled to show a significant cost difference among the portfolios.
- Duke should provide additional cost estimate details for the resource options included in each portfolio.
- Duke should also provide more detailed generating unit environmental compliance costs for each regulation.
- Duke's Electric Vehicle ("EV") forecast may overstate EV adoption, but

the OUCC does not recommend specific changes to the forecast.

- Duke should consider non-linear Behind the Meter ("BTM") Solar Adoption growth in future forecasts.
- Duke's adjustment to its load forecast to incorporate sensitivities for economic development is reasonable. However, the OUCC noticed a potential error in Duke's economic development load forecast adjustment. The adjustment is provided in MWhs but perhaps should be in GWhs.
- Duke should also model sensitivities to account for the potential future addition of large data center loads.
- Duke's historical load and energy generation data for 2013-2020 in its 2024 IRP is different from the historical data for the same time period reported in its 2021 IRP. Actual historical data should not change between IRPs.
- The OUCC recommends Duke model sensitivities regarding natural gas availability during cold weather events into its reliability modeling to better address resiliency and stability among portfolios.

Modeling Process, Portfolios, and Scorecard

Duke developed six generation strategies with an additional strategy related to abandoned implementation of Environmental Protection Agency ("EPA") Clean Air Act Section 111 Rule, the "No 111 Strategy." Duke's evaluation of these six strategies under three different scenarios with added sensitivity analyses on specific variables was an insightful approach and should be continued in future IRPs. The new stochastic analysis using the Strategic Energy Risk Valuation Model ("SERVM") to evaluate portfolio performance under real-world uncertainties, which provided power price variability in market purchases,[1] the inclusion of CO_2 emissions and forecasted operating costs are improvements from previous models used in Duke's IRPs.

These analytics led to an updated scorecard, which, from the OUCC's perspective, is an improvement from Duke's 2021 IRP. The scorecard comprehensively evaluated the Five Pillars by examining fifteen metrics. Five of these metrics captured measurements at two distinct points in time across the IRP horizon. The scorecard enhances how each portfolio performs over the 20-year evaluation period. However, the scorecard does not quantitatively measure the Stability Pillar, as Duke notes that it decided to take a narrative approach to evaluating the Stability Pillar after stakeholder recommendations.[2]

The addition of Cost Risk, Market Exposure, and Execution Risk provides additional insight into the weighting Duke used in analyzing its generation strategies. However, Duke's choice of Portfolio Blend 2 as the preferred portfolio was not obvious or transparent to the OUCC because the Present Value Revenue Requirement ("PVRR") and Customer Bill impact metrics do not show significant

[1] 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 5, p. 35.
[2] Duke Energy Indiana 2024 IRP, Volume 1, p. 48.

variation among the portfolios to fully support one option over another. This is likely because the resources in each portfolio considered do not vary significantly from the others, with most differences being due to proposed timing of generating unit retirements. All but one portfolio includes the addition of Combined Cycle Natural Gas Turbine ("CCGT") resources. Without much diversity among the resources considered in each portfolio, the costs of each portfolio tend to be very similar.

The OUCC acknowledges a variety of factors may lead Duke to only consider CCGT resources to replace retiring generation. MISO's seasonal resource adequacy requirements tend to favor firm, fast-ramping gas generation over intermittent resources. As explained in the next section, existing coal generation may be constrained by recent carbon emission regulations at the federal level. Nuclear generation has many regulatory and technical hurdles while the development of small modular reactor technology continues. However, Duke should attempt to consider greater variation in the portfolios it models where possible. For example, there does not appear to be a generation strategy where Duke considered adding combustion turbine ("CT") peakers instead of CCGTs. It is possible CTs could be used to support more renewable generation. Furthermore, if CTs are operated below a 20% capacity factor, they are not subject to the same efficiency requirements or potential carbon capture and sequestration ("CCS") requirements CCGTs that operate as intermediate or baseload resources would be under new carbon regulations.

While each proposal requires its own analysis, history has shown, generally, that conversions are more cost effective than retiring units and replacing their capacity. Additionally, the IRP states Duke has the option to convert the existing coal-fired units at Gibson and Cayuga either to 100% natural gas or 50% co-fired with natural gas. Either option would allow the existing units to continue operating beyond the originally projected retirement dates. However, doing so would require a number of additional infrastructure and maintenance projects. It is not clear the Edwardsport conversion achieves the same result because no portfolio considered retiring Edwardsport. Because Duke did not provide enough cost detail regarding the resource options considered, it is unclear if the costs of coal equipment retirement and the environmental remediation at these generating sites were adequately addressed. In a co-firing or conversion scenario, assets can be repurposed, possibly preventing some remediation costs and reducing the amount of new investment. The OUCC recommends additional cost estimate details be provided to clarify the benefits and costs of each resource option modeled.

Environmental Regulations Limiting Existing Asset Lives

Duke's proposed retirement dates contain significant changes when compared to Duke's 2021 IRP because the utility reflects the EPA's Greenhouse Gas New Source Performance Standards ("111 Rule") requirements finalized in April 2024. The final 111 Rule requires: (1) retirement of existing coal-fired units by 2032; or

(2) co-firing 40% natural gas by January 1, 2030, and then retiring those units by the end of 2038; or (3) 90% CCS by January 1, 2032.

In addition to these three compliance strategies under the federal rule, Duke could consider converting its existing coal-fired units to burn 100% natural gas. Existing natural gas-fired power plants are currently exempt from the 90% reduction requirement under the rule.[3] If Duke converted Edwardsport to only combusting natural gas, it would be considered an existing modified unit for purposes of rule applicability under air pollution regulations[4] and, thus, would currently be exempt from the CO_2 rule. This exemption may end in the future with EPA currently holding formal discussions in a non-regulatory docket on how carbon emissions from existing natural gas-fired power plants could be regulated, but the EPA has no planned rulemaking on these plants at this time.[5] Duke would need to decide whether to convert to natural gas by the end of 2030 to comply with the federal rule.

The Section 111 Rule also requires the State of Indiana to develop a state implementation plan for regulation of carbon emissions within two years of the publication of the final Section 111 Rule.[6] The state implementation plan may potentially impact coal units that convert to natural gas, but the state has flexibility under the Section 111 Rule to determine what standards may apply to such units.

No 111 Strategy

Duke considered a resource strategy under which the Section 111 Rule is either overturned by the courts or rescinded by the new Administration ("No 111 Strategy"). Given the Trump Administration's directive to re-evaluate any new regulation impacting the energy sector, this was a reasonable strategy for Duke to evaluate, even though the federal election results were not known at the time it submitted its 2024 IRP. While this portfolio would lead to delays in coal unit retirement or fuel switching dates, Duke would still retire or repower its existing coal units by 2036. Repeal of the 111 Rule would reduce the environmental regulatory burden on coal fired units, but these units will still face environmental regulations on air emissions and coal combustion residuals (CCR) disposal that increase the cost of running these units in comparison to other forms of energy.

To comply with Sections 316(a) and (b) of the Clean Water Act ("CWA"), Duke states it will likely need to install a closed-cycle cooling system to limit the impacts

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[3] US EPA Fact Sheet, Carbon Pollution Standards for Fossil Fuel-Fired Power Plants Final Rule; https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-overview.pdf.
[4] 40 C.F.R. Part 60, Subpart UUUUa §§60.5700a-60.5805a (https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-60/subpart-UUUUa).
[5] https://www.epa.gov/stationary-sources-air-pollution/nonregulatory-public-docket-reducing-greenhouse-gas-emissions.
[6] US EPA Fact Sheet, Carbon Pollution Standards for Fossil Fuel-Fired Power Plants Final Rule, State Plan; https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-state-plans-2024.pdf

to aquatic life at Cayuga.[7] Duke does not explain why such a system will be required for the existing coal units but not also required for a new CCGT constructed onsite. These requirements apply to all steam-fired generating units, including the heat recovery steam generating portion of a CCGT unit. Duke provides no compliance cost comparison for CWA Sections 316(a) and (b) compliance to burn coal versus replacement with natural gas-fired units at Cayuga. Gibson already has a closed cycle cooling system in place, so this is not an issue for the Gibson units.

The full impact of environmental compliance costs used in the IRP modeling is unknown. In addition to any potential increased costs from CWA Sections 316(a) and (b), continuing to burn coal would have increased environmental compliance costs due to coal combustion residuals disposal and continued operation of emission controls for sulfur dioxide, mercury, and other air toxics. These costs would not be required for natural gas burning units. Duke modeling inputs do not provide a breakdown of environmental fixed operating and management costs ("FOM") and environmental capital expenditures costs ("CAPEX"). The modeling data shows a significant reduction in these expenditures across multiple scenarios after the closure or conversion of coal units,[8] but the exact cost impact associated with each regulation cannot be determined from the materials Duke supplied.

Load Modifiers

Duke identified three primary uncertainties in its load forecasts: 1) EV adoption, 2) BTM solar adoption, and 3) economic development. Duke developed three cases for load forecasts: Low, Base, and High.

EV Adoption:

With changing administrations and slowing EV sales, Duke's projected EV adoption forecast appears overly optimistic.[9] Among Duke's 792,000 residential customers, each household possesses, on average, between two and three cars. Duke's EV forecast appears to assume about 75% of Duke's current residential customers are expected to replace one car with an EV by 2040. Duke states, "In 2023, ~7.5% of new vehicles sold in the U.S. were electric, compared to ~5.9% in 2022 and ~3.2% in 2021. This adoption trend is expected to continue and accelerate, especially considering federal initiatives, automaker goals, and the federal goal to have EVs make up at least 50% of new vehicle sales by 2030.[10] This is a very optimistic goal as well. While current federal incentives and regulations are aimed at improving EV sales, future policy changes or shifts in political leadership may impact EV adoption rates. Duke's EV model assumes the federal incentives stay

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[7] Duke 2024 IRP, Short Term Action Plan, p. 16.
[8] Duke 2024 IRP, Confidential Attachment, 111 Generation Strategies and No 111 – Ongoing CAPEX – FOM.
[9] https://apnews.com/article/stellantis-joint-venture-battery-plant-loan-kokomo-cc31d5f903e10d493b6ae9ea4663fa5e
[10] Appendix D: Load Forecast, p. 361.

consistent through the entirety of the forecast. The OUCC recommends Duke account for potential changes and/or improvements/enhancements to the existing policies such as changes to the Inflation Reduction Act ("IRA") in different scenarios. Duke also needs to consider the rate of the U.S. charging network expansion. Additionally, charging stations in the U.S. have an average reliability score of only 78%, meaning that about one in five do not work.[11] Therefore, network reliability would need to improve for customers to adopt EVs at this rate.

While automakers have announced ambitious EV targets, they are struggling with production challenges, battery supply chain issues, and fluctuating customer demand. Several major automakers such as Ford and GM have already scaled back their EV rollout plans. In July 2024, GM reduced its 2024 EV production forecast, lowering the upper estimate from 300,000 to 250,000 units. Toyota also announced it is postponing its plans to build EVs in the U.S. from 2025 to 2026, in addition to lowering its goal by 500,000 EVs.[12] With these industry setbacks, Duke's projection of reaching just over 600,000 EV units by 2040[13] is overly optimistic.

Regarding the charging behavior and load profiles, the forecast integrates charging load shapes based on national tools and averages. While this is beneficial, it may not accurately represent the specific conditions in Indiana. Incorporating data from Duke's ongoing managed charging pilot programs to refine the load profiles for peak demand forecasting will help improve Duke's forecast. The OUCC recommends Duke include local adoption barriers or facilitators such as charging infrastructure availability and urban-rural adoption disparities beyond the data provided by NREL, VAST, EVI-Pro, etc. While this data is comprehensive, Duke's forecast would benefit from incorporating more regionally specific data.

BTM Solar Adoption:

It appears Duke did not use a sigmoid annual growth rate as it did with EV adoption. Instead, it assumed a linear relationship. Anticipated rising energy costs and trending downward solar panel costs could lead to accelerated BTM solar adoption, so assuming linear BTM growth may understate its impact on reducing Duke's load. Greater BTM adoption could offset the significant projected load growth from EVs.

Economic Development Activity:

Unlike previous IRPs, Duke performed an ex-post modification to the energy forecast for economic development activity. Duke's load forecasting team screens potential economic site openings based on a sizing threshold of 20 MW and project

[11] The state of EV charging in America: Harvard research shows chargers 78% reliable and pricing like the 'Wild West': https://www.hbs.edu/bigs/the-state-of-ev-charging-in-america
[12] Automakers that pushed back EV goals and plans in 2024: https://www.foxbusiness.com/markets/automakers pushed-back-ev-goals-plans-2024.
[13] Appendix D: Load Forecast, p. 365.

maturity. The largest potential projects were added to the energy forecast. These were scaled down to reflect these plans are uncertain and some of the economic development may already be incorporated into Moody's service area forecasts. The OUCC agrees with Duke's approach of reducing the size of possible economic development projects within different scenarios to capture the uncertainty relating to whether projects actually come online. This in turn leads to a more accurate load forecast. For the Low load forecast, Duke assumes 25% of these screened economic development projects will be realized; for the Base load forecast, Duke assumes 60% will be realized; and for the High load forecast, Duke assumes 90% will be realized. The following table shows adjustments Duke made to the Base forecast reflecting economic development:[14]

Table D-5: Adjustments in the Base Load Forecast for Large Site Developments Year	**Adjustment (MWh [sic])**
2024	399
2025	917
2026	1,538
2027	2,055
2028	2,087
2029-2044	2,081

However, it appears the above Table D-5 contains an error showing megawatt-hours ("MWh") instead of anticipated gigawatt-hours ("GWh"). In terms of MWhs, 399 to 2,081 will make very little difference to load, and so it seems this table should reflect GWh. In addition, while economic development adjustments are provided in MWhs, it is unclear how these additions contribute to the system peak. The OUCC recommends Duke include peak MW additions for the economic development projects to show the system-wide impact of these projects. If these values in MWh were used in the load forecast for the preferred portfolio modeling, they should be corrected to properly capture economic development activity.

Large Load Customers

Duke did not adequately evaluate the emerging issue of hyper-scalers or large load customers / data centers ("DC"). The current Meta data center development in its service territory was not included in Duke's base analysis. Duke tested only 500 MW of new data center load sensitivity. Duke completed four of its five IRP stakeholder meetings before it became apparent that Indiana could become the home to larger DCs. Not long after Duke's November 1, 2024, IRP submission, Meta announced it was considering six phases at the LEAP Lebanon Innovation

[14] Table D-5, p. 356.

District.[15]

The OUCC recommends better characterization of market potential for large load customers and testing new large load demands. This could be achieved with higher load sensitivity analyses adding multiple 500 MW to 1,000 MW data centers loads in increments up to a total of 5,000 MW.

Historical Data Integrity

The OUCC also discovered historical data in this 2024 IRP that differs from what was provided in the prior 2021 IRP, detailed in Appendix C – Section 4. In the current 2024 IRP, Duke reports:[16]

Table D-12: Historical Actual System Peak, Generation, and Load Factor

Year	System Peak (MW)	Total System Generation (MWh)	Load Factor
2013	5,703	31,567,683	63.19%
2014	5,728	32,696,951	65.16%
2015	5,807	33,226,985	65.31%
2016	6,165	34,138,499	63.04%
2017	5,699	32,112,787	64.33%
2018	5,795	33,282,230	65.56%
2019	5,876	31,732,228	61.65%
2020	5,746	30,450,488	60.33%
2021	5,952	31,328,230	60.09%
2022	5,938	31,896,082	61.32%
2023	5,930	29,499,157	56.79%
2013-2023 Growth	227	-2,068,527	-0.89%
2013-2023 CAGR	0.26%	-0.68%	-1.72%

[15] Meta set to develop 1,500-acre data center campus outside Indianapolis, Indiana; https://www.datacenterdynamics.com/en/news/meta-set-to-develop-1500-acre-data-center-campus-outside-indianapolis-indiana/

[16] Table D-12, p. 371.

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However, Duke's 2021 IRP reports the following historical values (note that Summer Actual MW corresponds to the System peak):[17]

2021 IRP				
Year	Energy Actual GWh	Energy W/Normal GWh	Summer Actual MW	Summer W/Normal MW
History:				
2011	33,625	33,749	6,749	6,490
2012	31,028	31,369	6,494	6,510
2013	33,104	34,106	6,229	6,461
2014	32,063	31,728	5,830	6,084
2015	32,131	32,003	5,863	6,008
2016	32,318	32,267	6,079	6,181
2017	32,097	32,039	5,838	6,049
2018	31,532	31,547	5,904	5,895
2019	32,191	31,964	5,896	5,686
2020	31,447	31,678	5,755	6,029

The GWh energy and peaks do not line up, which is puzzling since these are historical numbers. For instance, Duke's 2024 IRP reports the 2013 peak as 5,703 MW, while the 2021 IRP reports the 2013 peak as 6,229 MW. Historical data is crucial for developing a baseline for the load forecast. While the load forecast is future oriented and incorporates more than a utility's historical data, historical data is a part of what is used to determine future rates of growth within the different rate classes. In addition, the IRP process is valuable as a record of where a utility is at a particular point in time, which is useful even when an IRP is superseded by the next edition. These values allow stakeholders to see how the utility's needs have evolved over time, and this is undercut when Duke uses different "actual," historical system usage between IRPs.

Analysis of The Five Pillars

Reliability, Resiliency, and Stability:

New to this IRP, Duke introduced "Enhanced Reliability Evaluation" modeling to assess whether Duke's candidate portfolios can maintain reliability and meet capacity obligations in light of the evolving resource mix of the wider MISO market. Duke describes that traditional conventional resource planning sought to accommodate peaks and valleys of customer electricity demand, but "with the evolution of the projected resource mix in MISO, available energy from these resources will vary with time and weather. Remaining electricity demand, after accounting for that variation, must be served in real-time by dispatchable sources

[17] Duke 2021 IRP, Sec. 5. (A)(3), p. 153.

to maintain system reliability."[18] Furthermore, Duke describes increasing operational uncertainty associated with renewable generation, stating that because of "unavoidable uncertainty" in day-ahead and real-time weather forecasting, future forecast errors are predicted to grow, and Duke will need adequate resources to prepare for this uncertainty.[19] In order to evaluate the candidate portfolio's ability to meet customer demand under a range of futures, Duke made use of the same model used in the Midcontinent Independent Service Operator's (MISO) probabilistic analysis, the SERVM.[20] While Duke's owned generation will be dispatched by the MISO, the SERVM model allows Duke to assess how its portfolio would perform under a range of weather patterns, unit availability, economic load forecast errors, and hourly dispatch availability. This allows Duke to estimate the Expected Unserved Energy ("EUE") or, in other words, how much customer demand would not be served if Duke's energy system was isolated from the wider MISO market. While it is unlikely that there will be no imports available from the market, this analysis allows Duke to determine how much its portfolios rely on market purchases and whether it makes disproportionate demands on MISO's electrical system relative to comparably sized companies. This approach marks an improvement from Duke's 2021 IRP and should be continued in the future.

While the Enhanced Reliability Evaluation also demonstrates the resiliency and stability of the portfolios Duke modeled, the OUCC recommends incorporating a range of assumptions regarding the availability of natural gas into Duke's reliability modeling to better address these Pillars. As MISO's generation mix evolves to include a larger portion of gas resources, there will be greater demand for natural gas that can affect whether a generator will be available for dispatch in extreme circumstances. Both Winter Storm Uri in 2021 and Winter Storm Elliot in 2022 highlighted the important role natural gas deliverability plays in grid reliability. With Winter Storm Elliot, PJM operators had to implement emergency procedures and a public appeal to reduce energy use to maintain reliability in the PJM footprint. Many gas generators expected to be available to meet the load were unable to comply with dispatch orders due to natural gas supply limitations. With Duke's preferred portfolio containing a significant addition of new natural gas fueled generation, it is important to account for the risk of natural gas supply disruptions during cold weather events.

Affordability

Duke measured affordability through two metrics: PVRR and project customer bill Compound Average Growth Rate ("bill CAGR"). The PVRR is intended to measure the long-term cost to customers, and the bill CAGR is intended to capture the near-term impacts to customers. For example, the Retire portfolio shows the

[18] Duke Energy Indiana 2024 Integrated Resource Plan, Volume 1, p. 399.
[19] *Id.*, p. 401.
[20] *Id.*, p. 406.

lowest PVRR of all portfolios but has the highest bill CAGR in 2035.[21] The resulting PVRRs and bill CAGRs show little variability among the portfolios, meaning one portfolio does not appear to have a clear cost advantage over others. However, the OUCC notes that Blend 1, where Cayuga Units 1 and 2 would be converted to natural gas rather than be replaced by a CCGT, has the second lowest PVRR, the second lowest bill CAGR in 2030, and the lowest bill CAGR in 2035.

Projected bill CAGR, taken from Duke's IRP, assumes the base rate amount on a typical residential bill will compound 4% from 2025 until 2030 and 3.1% from 2025 to 2035. The table below shows the projected base rate cost increase until 2035 of a 1,000-kWh electric bill for Duke's Preferred Portfolio (Blend 2).

<table>
<tr><th colspan="8">Table OUCC-1: Duke Future Electric Base Rate</th></tr>
<tr><td colspan="8">1000 kWh Residential Bill</td></tr>
<tr><td>Rate Change</td><td rowspan="2">March 2024</td><td>25.75% Rate Case</td><td rowspan="2">March 2025</td><td>4.0% CAGR</td><td rowspan="2">March 2030</td><td>3.1% CAGR</td><td rowspan="2">March 2035</td></tr>
<tr><td>Amount Change</td><td>$33.72</td><td>$35.69</td><td>$23.12</td></tr>
<tr><td>Total</td><td>$130.99</td><td></td><td>$164.71</td><td></td><td>$200.40</td><td></td><td>$223.52</td></tr>
</table>

The initial figures in this chart are based on Duke's current tariff and Step 1 Compliance Filing in IURC Cause No. 46038, and do not include trackers. However, the base rate figures alone paint a concerning picture regarding the preferred Blend 2 Portfolio Strategy's impact on bill affordability, as they show the potential for base rate increases totaling more than 70 percent within the next 10 years.

Environmental Sustainability

The OUCC appreciates that Duke based its assessment of CO_2 reductions using 2025 as a benchmark instead of a past year such as 2005. Using 2025 as a benchmark more clearly shows the attributable CO_2 emission reduction for each portfolio by not incorporating reductions that have already occurred through coal unit retirements made in the last decade.

Duke also appeared to take some stakeholder feedback to retire coal fired generation faster and add more renewable generation and battery storage resources through adding the Exit Coal Earlier (Stakeholder) generation strategy to its analysis. Even though the Company did not select this portfolio as its preferred resource plan, Duke showed a willingness to work with those stakeholders to incorporate their environmental sustainability concerns into Duke's IRP analysis.

It appears Duke considered the cost impact of environmental regulations assumed

[21] Duke 2024 IRP, Vol. 1, pp. 133-134.

for each of its portfolios. The 111 Rule drives the retirement dates for Duke's portfolios, and CWA Sections 316(a) and (b) also impact continued operation at Cayuga Units 1 and 2. However, as noted earlier, the OUCC recommends Duke provide clearer details on the costs associated with CWA Sections 316(a) and (b) compliance both for Cayuga Units 1 and 2 to remain operating as steam units and a new CCGT at the Cayuga site.

Conclusion

The OUCC appreciates the opportunity to submit these comments.

Office of Utility Consumer Counselor
IURC Cause No. 46193
Data Request Set No. 8
Received: 3/27/2025

OUCC 8.07

Request:

Refer to the direct testimony of Nathan D. Gagnon, p. 21, lines 10-15.

a. Does the "High Cost" case include greater capital costs associated for the conversion of coal units to natural gas or to co-fire coal and natural gas? If so, please provide the costs assumed for conversion within the "High Cost" case.
b. Please confirm the High Cost sensitivity analysis, as a variation of the preferred portfolio, assumed a CC replacement at Cayuga by the beginning of 2030 and 2031. If not confirmed, please explain.
c. Please confirm the High Cost sensitivity analysis did not optimize the selection of resources and assumed conversion to CCs for the Cayuga Units in 2030 and 2031. If denied, please explain.

Response:

a. Please refer to Attachment 6-A (NDG) pages 140-141 and pages 282-287 of the 2024 IRP for more detail on the "High CC/CT Cost" analysis. As stated on page 140, "the Company changed only the cost of CCs and CTs for this analysis."

b. The "High CC/CT Cost" analysis was performed for each generation strategy considered in the 2024 IRP to evaluate changes to resource selection in response to the change in cost assumption. The CC capacity for each resulting portfolio was not an input "assumption," it was a model output. The results of capacity expansion modeling for Blend 2 in the "High CC/CT Cost" included a single 2x1 CC being selected at the beginning of 2032. The capacity of the generic 2x1 CC is equal to the combined capacity of two generic 1x1 CCs, consistent with the Cayuga CC Project.

c. As explained in subpart b of this response, new resource selection, including selection of CCs, was optimized for the "High CC/CT Cost" analysis.

Witness: Nathan D. Gagnon

CERTIFICATE OF SERVICE

This is to certify that a copy of the **Indiana Office of Utility Consumer Counselor Public's Exhibit No. 3 Testimony of OUCC Witness John W. Hanks** has been served upon the following in the above-captioned proceeding by electronic service on May 8, 2025.

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