COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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ELECTRONIC 2024 INTEGRATED RESOURCE	)	
PLAN OF DUKE ENERGY KENTUCKY, INC.	)	**Case No. 2024-00197**
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SIERRA CLUB'S COMMENTS REGARDING DUKE ENERGY KENTUCKY, INC.'S 2024 INTEGRATED RESOURCE PLAN

Sierra Club respectfully submits these comments regarding Duke Energy Kentucky Inc.'s ("Duke" or "the Company") proposed 2024 Integrated Resource Plan ("2024 IRP").[1] The proposed 2024 IRP does not adequately comply with regulatory requirements for analysis and discussion of Duke's generation portfolio over the next fifteen years. These comments demonstrate that the IRP's consideration of alternatives, including full conversion and retirement and replacement of East Bend Unit 2 is arbitrary and inadequate and the Commission should reject them. While Duke claims that its IRP analysis supports its preferred plan to co-fire East Bend Unit 2, a careful review of the analysis demonstrates that full conversion of East Bend is actually the least-cost option. This conclusion is demonstrated by four facts. First, Duke's own modeling shows that full conversion is the least-cost alternative under the two main sensitivities analyses—where the U.S. Environmental Protection Agency's ("EPA") Clean Air Act Section

[1] Tyler Comings, Joshua Castigliego, and Jordan Burt at Applied Economics Clinic contributed to these comments.

111(d) rule (hereafter referred to as "111(d)")[2] is either (1) enforceable, or (2) eventually becomes non-enforceable. Second, East Bend Unit 2 is already [redacted] to operate and has been for several years—[redacted], let alone its fixed or capital expenses. Duke has exacerbated the impacts of this unit's [redacted] nature by operating the unit on a must-run basis rather than solely when it is economic to operate. Third, Duke's modeling included the costs associated with the East Bend Unit 2 Limestone Conversion Project across every scenario and sensitivity modeled. This assumption was wrong because this major capital project is avoidable under two alternatives—full conversion of East Bend Unit 2 or retirement and replacement of the unit. Modeling of these scenarios, when conducted properly, should at least test the exclusion of the $125 million Limestone Conversion Project cost. Fourth, full conversion of the unit from coal to gas provides relief from two regulatory obligations: it would not trigger Kentucky state law requirements for coal retirements and would not trigger a 2039 obligation to retire, as the co-firing option would, under 111(d). This would give Duke more flexibility regarding the timing of replacement generation.

Section I., below, provides background information and addresses the requirements for IRPs in Kentucky, as context for Sierra Club's arguments on Duke's IRP analysis of options for East Bend Unit 2. Section II. explains why Duke's IRP analysis falls short of these requirements by failing to adequately examine alternatives to continuing to burn coal at East Bend Unit 2, as part of Duke's mandate to determine and select the least cost option for its ratepayers. Section III. demonstrates that Duke's own modeling reveals there are other lower-cost options than the

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[2] New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units, 89 Fed. Reg. 39,798 (May 9, 2024).

Duke's preferred course. Section IV. discusses the challenging economics of East Bend Unit 2 and the availability of earlier retirement / replacement options that Duke did not consider. Section V. explains why Duke's sensitivity analysis fails to justify the co-firing alternative Duke proposes. Section VI. explains why Duke's assumption thatthe East Bend flue gas desulfurization ("FGD") Limestone Conversion Project would go forward as part of each modeling scenario was wrong. And, Section VII. explains that Duke also skewed its alternatives modeling by assuming a sustained high price for clean, renewable energy replacement options.

I. Background: Kentucky Integrated Resource Plan requirements and new EPA Rules.

Kentucky law requires that utilities "furnish adequate, efficient and reasonable service" and provides for "fair, just and reasonable rates."[3] Pursuant to these goals, Kentucky regulation provides for "regular reporting and commission review of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas, and satisfy all related state and federal laws and regulations."[4] Specifically:

> Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.[5]

As part of the IRP, the utility must provide its "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[6] In doing so, the utility's plan must "consider the

[3] K.R.S. § 278.030(1)-(2).
[4] 807 K.A.R. 5:058 (necessity, function, and conformity).
[5] *Id.* § 1(2).
[6] *Id.* § 8(1).

potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility."[7] The utility must "describe and discuss all options considered for inclusion in the plan:" for example, "demand-side programs."[8] For existing generation, the utility must include "for each facility" "[s]cheduled upgrades, deratings, and retirement dates," as well as detailed "[a]ctual and projected cost and operating information for the base year (for existing units) . . . and the basis for projecting the information to each of the fifteen (15) forecast years."[9] Further, "[t]he utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost."[10] For resource capacity, this includes "[p]lanned retirements."[11]

Finally, the integrated resource plan must "include a description and discussion of" key issues, including: "[k]ey assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;"[12] "[c]riteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;"[13] "[c]riteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;"[14] "[e]xisting and

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[7] *Id*.
[8] *Id*. § 8(2).
[9] *Id*. § 8(3)(b)(11)-(12).
[10] *Id*. § 8(4).
[11] *Id.*
[12] *Id.* § 8(5)(b).
[13] *Id.*§ 8(5)(c)
[14] *Id.* § 8(5)(d).

projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;"[15] and "[a]ctions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment."[16]

In short, Kentucky IRPs require rigorous and specific analysis and discussion of key issues regarding resource planning. This is unsurprising, since the purpose of the IRP is planning for the future to ensure that Kentuckians have access to affordable and reliable electricity. Utilities must analyze at a granular level the economics, reliability, and environmental risk of existing generation and contrast it with other options, including replacement generation.

Moreover, the IRP process is all the more important now in light of recently adopted Kentucky legislation, now codified at K.R.S. §§ 278.262 and 278.264. Section 278.264 requires that utilities apply to the Commission for approval of electric generating unit retirements. For fossil fuel-fired electric generating units, the law provides for "a rebuttable presumption against" retirement.[17] Rebutting that presumption requires, among other showings, evidence as to replacement capacity, whether the unit's retirement will "caus[e] the utility to incur any net incremental costs . . . that could be avoided by continuing to operate the . . . unit . . . in compliance with applicable law," and a showing "that cost savings will result to customers as a result of the retirement."[18] These questions that must be answered before retirement obviously require planning on the part of the utility—potentially, planning far into the future to anticipate how to ensure showings of cost savings and a lack of avoidable net incremental costs in order to maximize retirement at a time that is beneficial to customers. It is therefore all the more urgent

[15] *Id.* § 8(5)(e).
[16] *Id.* § 8(5)(f).
[17] K.R.S. § 278.264(2).
[18] *Id.* § 278.264(2)(a)-(b), (3).

and important that Duke and other Kentucky utilities plan, in the IRP, for eventual retirements of fossil fuel-fired units. It is likewise urgent and important that Duke and other utilities explain through "description and discussion" the assumptions, judgments, and criteria that underlie determinations regarding retirement, as well as the efforts that the utility is taking and will take to continue to "assess[] and refine[]" this analysis.[19]

As an additional factor, Duke's electric generating stations must also comply with new U.S. EPA regulations that restrict greenhouse gas emissions from coal-fired power plants. EPA's regulations, promulgated in 2024 under section 111(d) of the Clean Air Act, require coal-fired power plants to install equipment to reduce greenhouse gas emissions if they plan to retire after 2032.[20] Under the regulations, existing coal-fired power plants that plan to operate into 2039 and later years must install a carbon capture sequestration system that captures 90% of carbon emissions by 2032.[21] Coal-fired power plants that commit to retire before 2039 (but after 2032) must meet an emission rate consistent with 40% gas co-firing by 2030.[22] Gas-fired power plants, which are regulated under 111(b) of the Clean Air Act, that are in existence prior to 2030, have no greenhouse gas reduction obligations.[23]

The significant economic concerns with East Bend Unit 2 and the need to act quickly and nimbly to respond to recently promulgated environmental regulations, such as 111(d), require resource planning now. The Commission should inform Duke that the flaws and inadequacies of

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[19] 807 K.A.R. 5:058 § 8(5).
[20] *See generally* 89 Fed. Reg. 39,798.
[21] 89 Fed. Reg. at 39,838; *see* U.S. EPA, *Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants* at 6 (Apr. 25, 2024), https://www.epa.gov/system/files/documents/2024-04/cps-presentation-final-rule-4-24-2024.pdf.
[22] *See* 89 Fed. Reg. at 39,838; *Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants* at 6.
[23] *See* 40 C.F.R. § 60.5880b and compare the definition for coal-fired steam generating units to the definition for natural-gas fired steam generating unit.

its 2024 IRP and supporting analysis do not support co-firing as the least-cost option such that the Company cannot use the IRP to justify co-firing of East Bend. The Commission should inform Duke that if it would need to voluntarily (or the Commission could mandate it) update the IRP and its supporting analysis to correct the identified errors and inadequacies if the Company wanted to use such analysis to support a current or future certificate of public convenience and necessity ("CPCN") for a 40% co-firing application. The Commission should also advise Duke that based on the actual modeling and present value revenue requirement ("PVRR") results (not the misleading conclusions of the Company) that the actual least-cost option to provide adequate, efficient and reasonable service to Duke's customers is to fully convert East Bend Unit 2 to gas by no later than December 31, 2029.

II. Duke's IRP fails to meet the requirements of the IRP process, especially by failing to truly evaluate the least cost option with regard to East Bend Unit 2.

In the 2024 IRP, Duke's preferred plan for East Bend Unit 2 is to convert the plant to dual fuel operations ("DFO" or "co-firing") in 2030 and retire and replace the plant with a natural gas combined cycle unit ("NGCC") in 2039.[24] In choosing this alternative as its Preferred Plan, the Company conducted capacity expansion and production cost modeling using the Encompass model. The capacity expansion stage allows for economic optimization of new resource builds, subject to the Company's pre-set decisions about East Bend compliance with 111(d). The production cost stage then takes that fixed portfolio and dispatches the system optimally to arrive at a system-wide cost, or present value revenue requirement ("PVRR") for comparison of costs between scenarios and sensitivities. Sierra Club has no concerns with Duke using the Encompass model, in general, but Sierra Club does take issue with the framework

[24] Duke 2024 IRP at 61; Company response to STAFF-DR-01-023.

employed by Duke in this case. In our comments below, Sierra Club addresses the flaws in Duke's modeling approach and shows that full conversion of the unit to gas is the lowest-cost option and Duke should select this option as its preferred plan.

At first glance, it might appear that the Company robustly assessed the options for East Bend. However, a closer examination shows that the analysis was biased in favor of co-firing. The Company appears to have pre-determined this outcome, as its modeling is centered around that option. As shown below in Figure 1, the Company modeled 20 portfolios: 11 of which include compliance with the EPA's Clean Air Act Section 111(d)—which limits greenhouse gas emissions from existing fossil generators; and 9 of which assume that this law does not become enforceable and is either overturned by the courts or withdrawn by a future administration.

A. Duke's Modeling Framework Was Overly Focused on the Co-Firing Option

The Company generally considered three compliance options for East Bend: 1) co-firing with gas by 2030 and retirement and replacement with a natural gas combined cycle plant ("NGCC") in 2039 (the preferred plan); 2) full gas conversion by 2030 with no listed retirement date; and 3) retirement and replacement by 2032 with 111(d) or by 2036 without 111(d).[25] But of the 20 portfolios modeled, 13 of them include co-firing of East Bend, only two of them modeled full gas conversion, two of them modeled retirement prior to 2033, and three of them retire the unit in 2035 or later without conversion or co-firing (assuming no 111(d) compliance is needed). The results are clearly focused on the co-firing option. The Company should have tested each of its compliance options on a similar footing. For instance, it only modeled the co-firing option under alternate futures (high fuel, low fuel, and high load), rather than testing all three compliance options under those futures.

[25] Duke 2024 IRP at 46, 61.

Figure 1: Major Capital Projects at East Bend Unit 2, by portfolio[26]

Scenario	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
111(d) Co-fire '30						Co-fire								Retire	Replace	
111(d) Conversion '30						Convert										
111(d) Retire '32 - CC							Retire	Replace								
111(d) Co-fire '30 - CC						Co-fire								Retire	Replace	
111(d) Co-fire '30 - SMR						Co-fire								Retire	Replace	
111(d) Co-fire '30 - Retire '36						Co-fire					Retire	Replace				
111(d) Co-fire '30 - CC & Solar						Co-fire								Retire	Replace	
111(d) Retire '32							Retire	Replace								
111(d) Co-fire '30 - CC & Solar (High Fuels)						Co-fire								Retire	Replace	
111(d) Co-fire '30 - CC & Solar (Low Fuels)	FGD UPGRADE					Co-fire								Retire	Replace	
111(d) Co-fire '30 - CC & Solar (High Load)						Co-fire								Retire	Replace	
No 111(d) Co-fire '30						Co-fire								Retire	Replace	
No 111(d) Conversion '30						Convert										
No 111(d) Retire '36											Retire	Replace				
No 111(d) Co-fire '30 - CC						Co-fire								Retire	Replace	
No 111(d) Co-fire '30 - SMR						Co-fire								Retire	Replace	
No 111(d) Co-fire '30 - CC '36						Co-fire					Retire	Replace				
No 111(d) Co-fire '30 - CC & Solar						Co-fire								Retire	Replace	
No 111(d) Retire '36 - CC & Solar											Retire	Replace				
No 111(d) Retire '42 - SMR																

B. Several Key Issues with Duke's Modeling Invalidate the Co-firing Option

Duke claims that the plan to co-fire East Bend Unit 2 was selected due to the "cost competitiveness, flexibility for futures with and without the EPA Clean Air Act Section 111 Update, and the risk mitigation it provides through increased fuel and fleet diversity and the moderate level of market purchases."[27] But Duke has not justified the selection for several reasons, which Sierra Club will describe throughout these comments:

1. The Company's own modeling shows that full gas conversion is the lowest-cost option and is cheaper than co-firing—both under a 111(d)-compliance pathway or without a 111(d)-compliance obligation.
2. The Company should have modeled more options for ceasing coal at East Bend given its poor economics, including whether full conversion or retirement and replacement in an earlier year was lower cost.

[26] Company response to SIERRA-DR-01-009, Attachments 1-20.
[27] Company response to STAFF-DR-01-023c.

3. The Company only conducted sensitivity risk analysis (low fuel, high fuel, and high load) for the co-firing option; it did not do this exercise for full conversion or retirement and replacement options. Therefore, Duke's claim that co-firing mitigates risk is misleading because its sensitivity analysis does not allow for a comparison of risks across alternatives.
4. The Company's proposed flue gas desulfurization upgrade to handle limestone instead of quicklime ("Limestone Conversion Project") is included in every portfolio—as discussed above—but Duke could avoid this $125.8 million capital project with full conversion or early retirement and replacement. The PVRR analysis for these two alternatives is not accurate as it contains this avoidable project. So any comparison between the PVRR cost of co-firing versus full conversion or retirement and replacement options is unfairly handicapped and improperly skewed in favor of co-firing.
5. The Company has overstated the costs of clean replacement resources, which unfairly disfavors retirement and replacement options.

III. Duke's own modeling shows that both full conversion and early retirement and replacement of East Bend Unit 2 are lower-cost options than co-firing.

The Company has concluded that co-firing East Bend Unit 2 is the best way forward, but the modeling in this case actually points to full conversion as the best option. We reconstructed the costs of the Company's portfolios, or PVRR (present value revenue requirement) results based on the Company's discovery responses and found that the costs of the plans differ from what Duke is reporting. The Company is doing a calculation outside the Encompass model when constructing the PVRR. Duke notes that "[t]here are additional costs for existing units calculated outside of the model that contribute to the PVRR, this includes both Capital and Fixed O&M

costs associated with existing units based on capacity factors and starts that would result in units hitting minor and major maintenance intervals."[28]

Sierra Club, through its experts at Applied Economics Clinic recalculated the PVRR for Duke's portfolios with the data provided by the Company.[29] Our calculations also add the costs for existing units[30] provided by Duke to the revenue requirements directly reported in Encompass (which include the costs associated with the Limestone Conversion Project at East Bend).[31] Sierra Club then calculated the PVRR using the weighted average cost of capital ("WACC") of 7.29 percent[32] reported in the Company's modeling outputs. However, our calculations did not match the final PVRR reported by the Company. In fact, our PVRR calculations changed the rankings between the Company's modeling scenarios, as shown in Table 1—where the dark-shaded plan is the lowest-cost option. Based on our calculations, Duke's modeling shows that East Bend 100% gas conversion is the lowest-cost option and cheaper than co-firing or retirement. This option is cheaper regardless of whether 111(d) compliance remains enforceable. This undermines the Company's argument that co-firing is a reasonable path even if 111(d) compliance is no longer required.

[28] Company response to SIERRA-DR-02.002(c).
[29] AEC lead expert, Tyler Comings's CV is found here: https://aeclinic.org/tyler-comings
[30] Company response SIERRA-DR-02-002 CONF Attachment.xlsx.
[31] Company supplemental response to SC-DR-1-3, Confidential Attachments 80 through 99.
[32] Company supplemental response to SC-DR-1-3, Confidential Attachments 80 through 99.

Table 1: Comparison of PVRR Calculations for Duke Energy Kentucky's modeling scenarios[33] CONFIDENTIAL

[redacted]

The results shown here are close between conversion and co-firing but, as we discuss later, all costs shown here assume installation of the Limestone Conversion Project at East Bend,[34] even though that $125.8 million capital expense is unnecessary if the unit were to convert to gas. Thus, the savings of full conversion are likely higher if the Company avoided this unnecessary Limestone Conversion Project. In addition, the Company's "retire/replace" option relies mostly on combined cycle ("CC") gas replacement; but that could change if the Company used more reasonable costs for clean replacement options—as we also address later. Moreover, the Company could still add renewables simultaneously with gas conversion.

IV. Duke should have modeled an earlier "retire/replace" option given East Bend Unit 2's poor economics, even absent 111(d).

The framework utilized in this IRP analysis is centered around 111(d) compliance. The selection and timing of all the alternatives considered—converting, co-firing, or retiring the unit—all stem from compliance with 111(d) but are also tested in a non-111(d) future. But the Company has not tested retirement of East Bend prior to 2036 in a non-111(d) future. This

[33] Company response to SIERRA-DR-01-005, "SIERRA-DR-01-005_Attachment.xlsx"; Company response to SC-DR-2-2, "SIERRA-DR-02-002 CONF Attachment.xlsx"; Company supplemental response to SC-DR-1-3, Confidential Attachments 80 through 99.
[34] Company response to OAG 2-13.

presumes that only 111(d) would lead to the cost-effective retirement of coal and replacement with other generation, but this may not be the case. Indeed, the costs shown above illustrate that conversion from coal to gas is the lowest-cost option whether 111(d) compliance is required or not. The recent poor performance of the unit should have led Duke to test early retirement even without 111(d) compliance obligations. Conversion or retirement/replacement of the unit make sense with or without greenhouse gas emission compliance costs, while co-firing only makes sense if it is the lowest-cost option and if 111(d) is implemented. But the Company's modeling demonstrates that this option is not the least-cost option.

East Bend Unit 2 has been [redacted] in recent years, as evidenced by the unit [redacted]. In 2023 and 2024 (January to July—the latest provided by Duke), [redacted] Figure 2). These cost figures are conservative because they do not include variable operation and maintenance costs ("VOM") which Duke was unable to provide—yet these missing costs are also a part of the total variable or marginal costs of running East Bend.[35] Making a marginal profit from its energy sales is a necessary but not sufficient condition for a coal unit to be economic. A coal unit can still make a marginal profit on energy but be uneconomic given the magnitude of its forward-going fixed costs, such as typical fixed O&M, capital expenditures (capex), and future compliance costs. [redacted] even without accounting for fixed and capital expenses and other variable operating and maintenance costs.

[35] Company response to SIERRA-DR-01-010.

Figure 2: East Bend fuel costs and energy revenues CONFIDENTIAL[36]

[redacted]

The costs at the unit have increased in recent years due to the increased cost of quicklime used in the FGD for reducing sulfur dioxide (“SO_2”) emissions. In its request for a certificate of public convenience and necessity to upgrade the FGD to use limestone instead of quicklime, the Company noted that the cost of quicklime was negatively impacting the unit’s ability to compete in the PJM wholesale market.[37]

The poor economic performance has been exacerbated by the unit being self-committed almost all the time (when not on an outage). To facilitate the procurement of electricity on an optimal basis, PJM decides which generators to commit and dispatch to serve load—or “economic” commitment and dispatch, respectively. As part of this process, owners of generating units typically offer a bid equal to the variable cost of the unit (i.e., the cost it takes

[36] Company response KSES-DR-01-002 CONF Attachment 2.xlsx.
[37] Case No. 2024-00152, Company Application at 5.

the unit to produce the next unit of energy). PJM then commits the units on an economically optimal basis: the lowest-cost units available are committed first and then higher-cost units are committed until demand is satisfied at each hour. The highest-cost unit that clears the market in a given hour (the "marginal unit") sets the energy price for that hour (without factoring in transmission limitations). If a unit's bid is below the market price, it will make a profit or margin—assuming it is bidding its true operating cost. If the unit's bid is above that market price, PJM will not commit the unit.

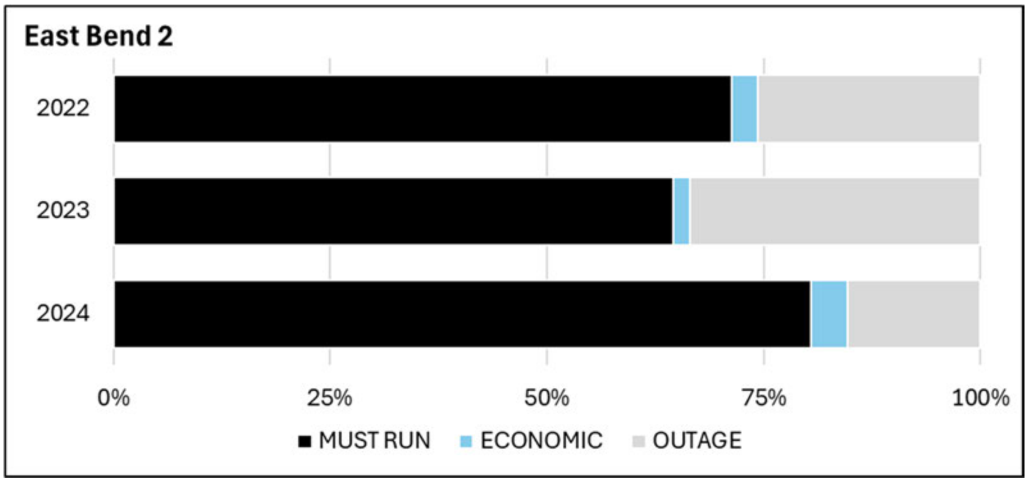
One way in which operators circumvent the economic commitment process is to force the unit to operate by "self-commitment" or submittal as "must-run" offer in PJM. This means the operator tells PJM that the unit will be on-line at a certain minimum capacity (also called "economic minimum") the next day and PJM can then decide to operate the unit further if it is cost-optimal (i.e., dispatch it at a higher output). Thus, under this exception, PJM is no longer deciding <u>if</u> the unit is on-line that day, but rather at what level the unit operates above its minimum threshold, if at all.

Instead of offering the unit for economic commitment from PJM, Duke has elected to submit East Bend to PJM as "must run" in nearly every hour it is not on an outage.[38] Figure 3 shows that in 2022, East Bend was committed as must-run 96 percent of the time when not on an outage.[39] In 2023, East Bend was committed as must-run 97 percent of the time when not on an outage.[40] Similarly, thus far in 2024, the unit was committed as must-run 95 percent of the time when not in an outage. While electing East Bend to be committed as must-run, Duke is forcing the unit to operate even in hours where its variable costs fall below the market price offered by

[38] Company response to AG-DR-2-3, "AG-DR-02-003_Attachment_1.xlsx".
[39] *Id.*"
[40] *Id.*"

PJM, which leads to Duke losing additional money for operating an [redacted] unit. On the contrary, if a unit is only committed economically, and the owner bids its true variable costs, then it would never lose money (on an energy basis) over the course of a year. The Company may prefer to have hands-on control over its unit's operations, but by doing this it is also exposing itself and ratepayers to market losses.

Figure 3: Commitment Status for East Bend Unit 2



Prior to the recent poor performance of the unit, the Company should have sought retirement/replacement or full conversion earlier given the results of the 2021 IRP. In that analysis, Duke evaluated 12 portfolios, six of which were optimized to minimize PVRR costs under three gas price forecasts, and three assumed carbon regulations.[41] The Company considered four different replacement options: conversion to gas, gas-fired combined cycle ("CC"), gas-fired combustion turbine ("CT"), and replacement of East Bend with renewables.[42] Under base gas price assumptions, the optimized plan, including carbon regulations, accelerated East Bend's retirement to 2027 and replaced the unit with new gas CC generation and solar photovoltaic ("PV") resources. The optimized portfolio with low gas prices and no carbon

[41] Case No. 2021-00245, Duke 2021 IRP at 42.
[42] *Id.* at 49.

regulations also accelerated the unit's retirement to 2025.[43] Despite these results, the Company chose a preferred plan that retired the unit in 2035.[44] If the Company had instead pursued retirement or conversion by 2025, it could have saved ratepayers from [redacted] and avoided the need for the Limestone Conversion Project which is currently planned for installation in 2025 and 2026.

V. The Company's sensitivity analysis does not justify co-firing because it does not measure the risks of alternatives

The Company should have tested all of its other resource options—including co-firing, conversion or early retirement—under future uncertainties. The purpose of modeling a sensitivity is to test how alternatives would fare under uncertain future conditions. When done properly, this type of modeling is meant to show the range of possible outcomes between plans to better assess the risks inherent in each plan and make a more informed decision. In this IRP, Duke has run sensitivities under individual futures with high fuel prices, low fuel prices, and a high load forecast; but only for its preferred plan of co-firing the unit. The results of this limited analysis are unsurprising and add no justification to the pursuit of this plan: 1) lower fuel prices [redacted] the costs of the preferred plan; 2) higher fuel costs [redacted] the costs of the preferred plan; and 3) higher load [redacted] costs of the preferred plan because more capacity additions are needed.[45] These conclusions were already obvious without running any modeling; and as a result the Company's sensitivity analysis adds no value or validity to the preferred plan.

A utility should instead use a sensitivity analysis as a step towards a robust resource decision, not simply applied to test one predetermined plan. A robustly tested plan fares well

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[43] Duke 2021 IRP at 42.
[44] *Id.* at 65.
[45] Company response to SIERRA-DR-01-005, "SIERRA-DR-01-005_Attachment.xlsx"; Company response to SC-DR-02-002, "SIERRA-DR-02-002 CONF Attachment.xlsx"; Company supplemental response to SC-DR-01-003, Confidential Attachments 80 through 99

under multiple, plausible futures. Running all decision options under the same sensitivities and then comparing the results to one another, within each future, would have provided useful information. Most importantly, it would have afforded an apples-to-apples comparison of the risks of all decision options in order to inform the choice of a preferred plan. For instance, in its Indiana IRP, the Company conducted many sensitivities on all six of its portfolio options it considered.[46] Duke's methodology in Kentucky unfortunately puts the cart before the horse.

VI. Duke should not have included the Limestone Conversion Project cost under the full conversion or retire/replacement option because that expenditure is likely avoidable, especially in light of the new offer.

The Company recently filed an application for a certificate of public convenience and necessity to install the Limestone Conversion Project at East Bend so that it can utilize limestone instead of quicklime. As noted previously, the costs of quicklime have increased such that Duke had found that continuing to operate the unit on quicklime was economically unsustainable.[47] The cost of quicklime is so high that Duke has requested authorization to spend $125.8 million in ratepayer dollars to convert to a limestone sorbent. In this IRP, as shown in Figure 1, all of the modeling in this case embedded the capital cost of the Limestone Conversion Project into every scenario.[48] This is an unreasonable assumption because Duke could avoid the project if the unit were to convert to gas or retire.

Duke admitted that the Limestone Conversion Project was avoidable if East Bend 2 fully converted to gas.[49] Therefore, the Commission should not conclude that the Limestone Conversion Project is always necessary—or was necessary at the time the IRP modeling was

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[46] 2024 Duke Energy Indiana Integrated Resource Plan Stakeholder Meeting 5, Slides 22-28. Available at: https://www.duke-energy.com/home/products/indiana-integrated-resource-plan.
[47] Case No. 2024-00152, Direct Testimony of John A. Verderame, p. 18, ll. 15-21.
[48] Company response to AG 02-013.
[49] Case No. 2024-00152, Company response to SIERRA-DR-01-011.

conducted. Duke's handling of this assumption does not meet the strictures of Kentucky law. The IRP should not merely lock in an assumption, but instead toggle between them, showing "how uncertainties in those assumptions and judgments were incorporated into analyses."[50] Instead, Duke should have at least tested the full conversion scenario (and sensitivities) and the retire/replace scenario (and sensitivities) without the avoidable capital costs associated with the Limestone Conversion Project. The problems associated with this unreasonable universal assumption are more pronounced now as Duke recently noted that the Limestone Conversion Project may be unnecessary because of a potential new long-term contract for quicklime.[51]

Given that the Limestone Conversion costs are similar in magnitude to the costs of co-firing and conversion of the unit, inclusion of the avoidable cost in the full conversion modeling run significantly distorts the results.[52] The capital costs modeled in the IRP modeling include $[redacted] million for the Limestone Conversion Project, $[redacted] million upfront for the co-firing with $[redacted] million per year for the costs of the pipeline, and $[redacted] million for the full gas conversion with $[redacted] million per year for the pipeline.[53] So the upfront costs for the co-firing with the Limestone Conversion are $[redacted] million—discussed below is how this number should actually be $[redacted] in upfront costs after an outdated number is corrected—and $[redacted] million in pipeline costs for 10 years.

Moreover, Duke modeled the outdated cost for the Limestone Conversion Project. The model included a $[redacted] million for the Limestone Conversion Project but in application for a CPCN for the Limestone Conversion Project, the Company stated that the capital costs were

[50] 807 K.A.R. 5:058 § 8(5)(b).
[51] Case No. 2024-00152, Company's Motion for Stay of Proceeding.
[52] Case No. 2024-00152, Company Application, p. 12.
[53] Company response SIERRA-DR-02-002 CONF Attachment.

actually \$125.8 million.[54] This more than [redacted] percent higher than what Duke used in its IRP modeling.

Full conversion of East Bend Unit 2 also provides relief from two regulatory obligations. First, as discussed above, the Kentucky legislature recently passed a law that requires utilities apply to the Commission for approval of electric generating unit retirements.[55] For fossil fuel-fired electric generating units, the law provides for "a rebuttable presumption against" retirement.[56] Rebutting that presumption requires, among other showings, evidence as to replacement capacity, whether the unit's retirement will "caus[e] the utility to incur any net incremental costs . . . that could be avoided by continuing to operate the . . . unit . . . in compliance with applicable law," and a showing "that cost savings will result to customers as a result of the retirement."[57] Importantly, full conversion of this unit to operate on gas would not trigger compliance obligations as the unit is not being retired.

Second, full conversion of East Bend Unit 2 to gas would negate the mandatory obligation to retire the unit or install carbon capture and sequestration equipment by 2039 under 111(d). Coal-fired power plants that commit to retire before 2039 (but after 2032) must meet an emission rate consistent with 40% gas co-firing by 2030.[58] Gas-fired power plants, which are regulated under 111(b) of the Clean Air Act, that are in existence prior to 2030 have no greenhouse gas reduction obligations.[59] So if Duke were to convert East Bend Unit 2 to gas by 2030 it would not trigger a 2039 obligation to retire or install carbon capture equipment, as the

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[54] Case No. 2024-00152, Company Application, p. 12.
[55] K.R.S. Section 278.264
[56] Id. § 278.264(2).
[57] Id. § 278.264(2)(a)-(b), (3).
[58] *See Final Carbon Pollution Standards to Reduce Greenhouse Gas Emissions from Power Plants* at 6.
[59] *See* 40 C.F.R. § 60.5880b and compare the definition for coal-fired steam generating units to the definition for natural-gas fired steam generating unit.

co-firing option would. This would give Duke more flexibility regarding the timing of replacement generation.

Finally, Duke's handling of the capital costs associated with the Limestone Conversion Project are a text-book example of an inappropriate piecemeal analysis. The Company has stated that gas conversion could take four to five years to implement due to the length of time necessary to hook up to existing gas pipelines.[60] But the Company fails to acknowledge that it could have initiated this conversion process far sooner, as early as 2020, when it first understood the expected rise in quicklime costs. In the CPCN case, in order to support the Limestone Conversion Project, the Company modeled the costs of East Bend Unit 2 with and without the upgrade. But Duke only conducted modeling in that case through 2029, and did not analyze any further investments such as conversion, co-firing, or retirement of the unit following that date.[61] This is the definition of "piecemeal planning," where a project is looked at in isolation rather than considered along with the suite of other investment decisions that are upcoming. Between the two dockets—the IRP and the CPCN application for the Limestone Conversion Project—Duke treated two major resource decisions (limestone conversion of the FGD scrubber system and the gas conversion and/or retirement of the facility) separately whereas it should have evaluated these future scenarios in one process in order to understand the cost implications for ratepayers and make an informed choice that reflects the least-cost option on the whole.

The Commission should advise Duke to stop such myopic analyses and instruct Duke that in its negotiations with the quicklime supplier, the Company should align its contract with the timing for the least-cost option moving forward. Duke states that it would take four to five

[60] Company response to STAFF-DR-01-022.
[61] Case No. 2024-00152, Company response to SIERRA-DR-01-072.

years to convert East Bend 2 to gas.[62] Duke should thus seek a five-year quicklime supply and start the process for conversion of East Bend 2 rather than sign a longer-term contract that would unnecessarily prolong the unit's operation on coal.

VII. The Company overstated prices for clean replacement in the medium- and long-term.

The Company conducted capacity expansion modeling to test what new resources would be built given the decision options at East Bend Unit 2. This type of modeling is standard utility planning practice, but the cost assumptions for new resources are instrumental in conducting a fair assessment. Unfortunately, Duke has assumed that clean replacement options are expensive and will remain so through the 17-year modeling period. This unreasonable assumption biased the results in favor of gas options, instead of new clean energy resources such as wind, solar, and batteries.

For new clean energy resources, Duke constructed long-term forecasts of capital costs using the U.S. Energy Information Adminstration's ("EIA") 2023 Annual Energy Outlook ("AEO") data in combination with data prepared by Guidehouse for solar, wind, and storage resources.[63] For solar resources, Duke's forecast sets the initial project cost at [redacted] derived from EIA 2023 AEO and Guidehouse data.[64] For wind resources, Duke's forecast starts at [redacted] and for battery storage resources it starts at [redacted].[65] Sierra Club, through its expert AEC, compared Duke's forecasts with more up-to-date cost projections

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[62] Company response to STAFF-DR-01-022.
[63] Company response to Sierra Club Data Request SIERRA-DR-01-011, "SIERRA-DR-01-011_Attachment".
[64] Company response to Sierra Club Data Request SIERRA-DR-02-003(b), "SIERRA-DR-02-003(b) CONF Attachment.xlsm".
[65] *Id.*

from the National Renewable Energy Laboratory's ("NREL") 2024 Annual Technology Baseline ("ATB"), including NREL's sensitivities for low, mid, and high costs (i.e., NREL's Advanced, Moderate, and Conservative cases, respectively). Duke's assumed capital costs for these resources are [redacted] than those reported in NREL's 2024 ATB—as shown below in the figures below for solar, wind and storage resources, respectively.

Figure 4: Capital costs for solar PV ($/kW nominal, unsubsidized)[66] CONFIDENTIAL

[redacted]

[66] National Renewable Energy Laboratory (NREL). 2024. *2024 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*, available at: https://atb.nrel.gov/electricity/2024/data; Company response to Staff Data Request STAFF-DR-01-005(a), Confidential Attachment.

Figure 5: Capital costs for wind ($/kW nominal, unsubsidized)[67] CONFIDENTIAL

[redacted]

[67] National Renewable Energy Laboratory (NREL). 2024. *2024 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*, available at: https://atb.nrel.gov/electricity/2024/data; Company response to Staff Data Request STAFF-DR-01-005(a), Confidential Attachment.

Figure 6: Capital costs for storage ($/kW nominal, unsubsidized)[68] CONFIDENTIAL

[redacted]

The Company only modeled outdated and unreasonably high costs for clean energy resources.[69] The Company's costs of solar and battery storage are roughly [redacted] percent higher than the NREL's mid-price forecast in 2030; Duke's wind costs are roughly [redacted] percent higher as well. Sierra Club understands that there were temporary, short-term cost increases due in part to interconnection delays. But there are a concerted efforts across the U.S. to mitigate this obstacle—including in PJM. It is therefore widely assumed and forecasted that the high costs of clean replacement are temporary, yet the Company did not model a scenario or sensitivity with lower capital costs for clean energy resources.[70] Duke claimed that its inclusion of the Inflation Reduction Act ("IRA") and U.S. Environmental Protection Agency's Clean Air Act Section 111

[68] National Renewable Energy Laboratory (NREL). 2024. *2024 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*, available at: https://atb.nrel.gov/electricity/2024/data; Company response to Staff Data Request STAFF-DR-01-005(a), Confidential Attachment.
[69] Company response to Staff Data Request STAFF-DR-01-005(a), Confidential Attachment.
[70] Company response to Sierra Club Data Request SIERRA-DR-01-014.

Update "provided sufficient incentives to demonstrate how the model selects renewable resources."[71] We agree with the inclusion of these credits but the Company also needs to contemplate a future where capital costs return to normal, rather than assume that these recent price increases will persist.

VIII. Conclusion

While Duke claims that its IRP analysis supports its preferred plan to co-fire East Bend 2, a careful review of the analysis actually demonstrates that full conversion of East Bend is the prudent option. This conclusion is supported by four facts. First, the Company's own modeling showed that full conversion of East Bend 2 is the lowest-cost option—with and without 111(d) compliance. Second, the unit has fared poorly operating on coal in recent years, not even [redacted]. Duke has amplified the impacts of this unit's uneconomic nature by operating the unit on a must-run basis rather than when it is economic to operate. Third, Duke's modeling improperly included the avoidable costs associated with the Limestone Conversion Project, which is not needed if East Bend 2 is fully converted to operate on gas. Fourth, full conversion of the unit would not trigger Kentucky state law requirements for coal retirements and would not trigger a 2039 obligation to retire, as the co-firing option would. This would give Duke more flexibility regarding the timing of replacement generation. The Commission should inform Duke that the flaws and inadequacies of its 2024 IRP and supporting analysis do not support co-firing as the least-cost option and cannot be used to justify co-firing to "furnish adequate, efficient and reasonable service" to Duke's customers. The Commission should tell Duke that if it would need to voluntarily (or the Commission could mandate it) update the IRP and its supporting analysis to correct the identified errors and inadequacies if the

[71] *Id.*

Company wanted to use such analysis to support a current or future CPCN application to co-fire East Bend Unit 2. The Commission should also make clear that the modeling in the 2024 IRP provides is inadequate support to Duke's current application for the Limestone Conversion Project. Finally, the Commission should advise Duke that based on the actual modeling and PVRR results, the actual least-cost option to provide adequate, efficient and reasonable service is to fully convert East Bend 2 to gas by no later than December 31, 2029.

Dated: November 6, 2024

Respectfully submitted,

/s/ Joe F. Childers

Joe F. Childers
Childers & Baxter, PLLC
The Lexington Building
201 West Short Street, Suite 300
Lexington, KY 40507
(859) 253-9824
joe@jchilderslaw.com

Of counsel

(not licensed in Kentucky)

Kristin A. Henry
Nathaniel Shoaff
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
kristin.henry@sierraclub.org
nathaniel.shoaff@sierraclub.org

CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of *Sierra Club's Comments Regarding Duke Energy Kentucky's Inc.'s 2024 Integrated Resource Plan* in this action is being electronically transmitted to the Commission on November 6, 2024, and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

/s/ Joe F. Childers
JOE F. CHILDERS