COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2024 INTEGRATED RESOURCE PLAN OF DUKE ENERGY KENTUCKY, INC.	))	CASE NO. 2024-00197

DUKE ENERGY KENTUCKY, INC's PUBLIC REPLY COMMENTS

I. Introduction

On June 21, 2024, in compliance with the Commission's August 1, 2023, Order in Case No. 2021-00245,[1] Duke Energy Kentucky, Inc., (Duke Energy Kentucky of the Company) filed its Electronic 2024 Integrated Resource Plan (2024 IRP). On July 16, 2024, the Kentucky Public Service Commission established a procedural schedule in this proceeding that, among other things, provided time limits for intervention, discovery, the ability to file intervenor comments and the Company to submit reply comments (Procedural Order).[2] An evidentiary hearing was set to commence December 10, 2024.

The Commission granted the intervention requests of the Office of the Kentucky Attorney General (KY AG), Sierra Club, and Joint Intervenors, Kentucky Solar Energy Society, Kentuckians for the Commonwealth, and Kentucky Resources Council (Joint Intervenors). Consistent with the Commission's Procedural Order, the three intervening parties filed their respective comments.

[1] *In the Matter of the Electronic 2021 Integrated Resource Plan of Duke Energy Kentucky, Inc.,* Case No. 2021-00245 (KY.P.S.C. Order) (Aug. 1, 2023).
[2] *Id.* (KY.P.S.C. Order) (July 16, 2024).

II. Overview of the Company's Resource Plan

The Company's planning process assesses various supply-side, demand-side and emission compliance alternatives to develop a long-term, cost-effective portfolio to provide customers with reliable service at reasonable costs. The IRP planning process involves various assumptions such as future energy prices, future environmental compliance requirements and reliability constraints. Duke Energy Kentucky's load forecasting group develops the load forecast by: (1) obtaining service area economic forecasts primarily from Moody's Analytics; (2) preparing an energy forecast by applying statistical analysis to certain variables such as number of customers, economic measures, energy prices, weather conditions, *etc.;* and (3) developing monthly peak demand forecasts by statistically analyzing weather data. The Company updates the load forecasts on a regular basis and the updated load forecasts are used for all modeling analysis. It is important to note that while Duke Energy Kentucky develops internal load forecasts for system planning purposes, the actual load forecast and the Duke Energy Kentucky PJM Interconnection, L.L.C (PJM) load obligation, which includes peak coincidence factors and system reserve requirements, is calculated by PJM and can differ slightly from the Company's internal forecast.

The Company's 2024 IRP shares some of the characteristics of its previous IRPs. It represents Duke Energy Kentucky's proposed roadmap to meet future energy and demand requirements without compromising reliability of service, energy affordability or the power demands of a growing region. The 2024 IRP reflects updated fuel and load forecasts, as well as updated new generation capital costs reflecting a dynamic macroeconomic and inflationary environment impacting supply chain and resource costs. Additionally, the 2024 IRP includes updated policies at both the state and federal level including:

- The Inflation Reduction Act (IRA) particularly expanded investment and production tax credits for non-CO_2 emitting generating resources;
- The Environmental Protection Agency (EPA) Clean Air Act (CAA) Section 111 April 2024 Updates (US EPA 111d) regulating existing coal and new natural gas generation facilities;
- Updates to Effluent Limitation Guidelines (ELG); 316 a & b (thermal discharge limits and fish impingement/entrainment at water intakes); and tightened Mercury & Air Toxics Standards (MATS); and
- Removal of a CO_2 tax on plant emissions as a likely future policy primarily due to the inclusion of the IRA and US EPA 111d provisions.

Through analysis of multiple scenarios, the Company evaluated the resource needs of the system, and specifically involving East Bend, the Company's primary base load resource. Duke Energy Kentucky evaluated potential pathways for East Bend's continued operation and replacement options under two scenarios: with and without the US EPA 111d. For each scenario, an optimized portfolio was developed. Additionally, alternate portfolios were developed based on results of the optimized portfolios and to test resource-specific strategies. The alternate portfolios analyzed model results from the two scenarios with and without US EPA 111d, as it is important to understand both the impacts and risks of this policy in the development of the Preferred Portfolio.

The 2024 IRP analyzed seventeen portfolio scenarios. The 2024 IRP reflects Duke Energy Kentucky's preferred portfolio that includes conversion of East Bend from 100 percent coal generation to coal generation with gas co-firing capabilities, or dual fuel operation (DFO) to be in service as of December 31, 2029. The 2024 IRP includes continued operation of the Woodsdale CT's and the addition of a combined cycle (CC) at East Bend beginning on January 1, 2039. The

East Bend DFO conversion is driven by environmental regulations, primarily the US EPA 111d that was not in place in 2021. US EPA 111d limits coal plants to four compliance pathways:

- Retire by January 1, 2032, without restriction on operation until retirement;
- Convert the unit to full natural gas operation by January 1, 2030;
- Convert to at least 40% gas-cofiring by January 1, 2030; or
- Add Carbon Capture and Sequestration (CCS) by January 1, 2032.

As part of its modeling, the Company determined that natural gas-cofiring was the preferred strategy because it adds needed fuel diversity and security to the Duke Energy Kentucky system, reduces customers' exposure to PJM market prices, provides for a measured energy transition while allowing time for technological advancements related to permanent replacement generation, and is in line with Kentucky's energy policies and priorities.

The 2024 IRP analyzes the portfolio beyond the life of East Bend's December 31, 2038, estimated retirement date because of the US EPA 111d, and includes a 1x1 CC as the optimal replacement resource for East Bend at the time of its retirement. Additionally, the IRP also includes renewable resource assumptions. While the 2024 IRP identifies replacement generation as a 1x1 CC, there is time between this filing and East Bend's compliance-driven retirement to allow other technologies such as nuclear small modular reactors (SMR) or CC paired with CCS (CC w/ CCS) to evolve such that these other technologies may be used as a replacement for East Bend.

III. Intervenor Comments

A. Summary of the KY AG Comments

The Ky AG believes that the 2024 IRP contains a thorough analysis of the Company's system and its short and long term supply and demand-side requirements given the current and future regulatory environment.[3] The KY AG posits that the company's 2024 IRP continues to appropriately identify the need for dispatchable resources by 1) extending the useful life of East Ben for as long as possible in the current environmental regulatory environment; and 2) by identifying the precise type of new replacement dispatchable resource and approximate start-up date.[4] The KY AG echoes concerns raised by PJM regarding the need for dispatchable thermal generation and the risks of a renewable transition that is too aggressive[5] and ultimately supports Duke Energy Kentucky's preferred path of converting East Bend to dual fuel operation and eventual replacement by a combined-cycle natural gas unit.

The Company appreciates the Ky AG's review of the 2024 IRP and the detailed discovery it conducted in this proceeding and agrees with its conclusions.

B. Joint Intervenor Comments

1. Summary of Joint Intervenor Comments.

Joint Intervenors' comments focus primarily on the Company's demand-side management (DSM) resources, arguing that the IRP did not integrate evaluation of potentially cost-effective DSM savings as a generation alternative, describing it as piece meal and siloed. They further argue that the Company's IRP does not report or evaluate resource-related decision points, alleging the IRP, among other things, lacks transparency. Joint Intervenors are critical of the 2024 IRP for not

[3] KY AG Comments pp. 7-8.
[4] *Id.* pg. 9.
[5] *Id.* pg. 10.

considering the economically optimal retirement date for East Bend, given its age and fails to evaluate transmission and distribution alternatives. While the Company appreciates Joint Intervenors' perspective, the Company disagrees as explained below.

2. The Consideration of DSM Programs in the IRP is reasonable, consistent with prior IRPs, and follows Commission precedent to evaluate DSM programs in separate regulatory proceedings.

Duke Energy Kentucky evaluates its portfolio of DSM Programs on a regular basis to ensure that its portfolio continually offer programs that are relevant to customers, incorporate new technologies, and are cost effective. The Company uses information from other utility jurisdictions that Duke Energy Corp.'s affiliated utilities operate in, as well as third-party experts and industry associations to identify gaps and opportunities to enhance its existing programs and leverages its two annual DSM regulatory proceedings in Kentucky: the annual cost recovery filing for Demand Side Management and the annual Commission-established modification filing to implement updates and enhancements to its portfolio of programs.[6] One example of a recent enhancement to an existing program in the portfolio (The Power Manager Program) is the ability to utilize smart thermostats as an implement to shift load away from peak periods. While Company continues to look at ways to enhance its portfolio, it is important to note that Kentucky's regulatory requirements around DSM programs require that, except for a limited number of programs targeting income qualified customers, the Company's programs and portfolio should only include

[6] On November 15, 2012, Duke Energy Kentucky filed an application for the cost recovery of DSM programs. The Company's application was docketed as Case No. 2012-00495. On April 11, 2013, this Commission approved that Application and ordered Duke Energy Kentucky to file, by August 15, annually, an application requesting any program expansion(s) and to include: (1) an Appendix A, setting forth the Cost Effectiveness Test Results of DSM programs, (2) an Appendix B, setting forth the recovery of program costs, lost revenues, and shared savings that are used in determining the true-up of proposed DSM factors; and (3) a signed and dated proposed Rider DSMR, DSM rate, for both electric and natural gas customers, Appendix C.

cost effective measures.[7] Because of this Kentucky cost-effective requirement, designed to ensure that the customer and utility system benefits that can be achieved from the program are greater than the costs borne by the participating customer and all utility system customers, there are some DSM programs and technologies that are offered in other states that simply cannot be offered in Kentucky. The Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Kentucky Resources through their comments, assert that Duke's IRP describes in detail existing approved programs but does not offer any information to evaluate portfolio implications of any other levels of program savings. The Company disagrees with this critique. The Company's DSM forecast included resource planning needs to be based on programs that are technically feasible and can be implemented in Kentucky, since over-estimating the impacts could jeopardize system reliability and the ability to serve customers. Ignoring the that programs need to be cost effective under the Total Resource Test, are commercially available in the market and be attractive for customers to participate in, would not be prudent resource planning. The Company's approach of including supply and demand-side resource for consideration if they are technically feasible and commercially available in its service territory during the planning window is prudent resource planning and does not diminish its commitment to continue to incorporate ne DSM programs and enhancements to its portfolio as they become feasible and cost effective.

3. The evaluation of Supply-Side Resources in the IRP was reasonable and transparent.

Joint Intervenors express concern with both the scope of the IRP analysis, and the level of detail and transparency in the report. With respect to scope, Joint Intervenors contend that the

[7] In Case No, 2017-00427, the Commission stated that the cost-effectiveness of Duke would be closely reviewed in the 2019 DSM filing. Hence, the Commission finds that the individual modifications that are not cost-effective, as demonstrated by a TRC score of less than one, are unreasonable and should not be approved. The Commission further finds that the proposed modifications that are cost effective, as demonstrated by a TRC score greater than one, are reasonable and thus should be approved.

Company should have evaluated several additional items as part of the IRP, including the construct through which the Company participates in PJM capacity markets, potential future carbon regulation other than US EPA 111d, and optimal transmission and distribution projects. In each case, the Company maintains that the scope of its analysis in the 2024 IRP was appropriate.

Joint Intervenors argue that the Company should have evaluated the relative merits of Fixed Resource Requirement (FRR) and Reliability Pricing Model (RPM) participation in PJM in the 2024 IRP. However, the difference between the two constructs does not affect resource selection in IRP modeling nor the identification of the preferred portfolio. Under both constructs, the Company would plan to secure sufficient capacity to meet its projected peak demand plus a reserve margin. This amount would be the same under both constructs, and there is no difference in resource capacity accreditation between the two constructs. In other words, in an IRP context, the difference between FRR and RPM is meaningless. Therefore, it would not be reasonable (or even possible) to expand the scope of the IRP to attempt to include an evaluation of the two structures.

Joint Intervenors also argue the Company should have expanded the scope of potential future carbon regulations considered in the 2024 IRP. In the 2024 IRP, the Company evaluated scenarios with and without US EPA 111d. Joint Intervenors suggest that, in the cases without the rule, the Company should have evaluated other forms of regulation limiting or imposing costs on carbon emissions or both. Such additional evaluation would have been redundant with the scenarios that include US EPA 111d, which is a reasonable stand-in for other forms of potential carbon regulation in terms the impact such hypothetical regulations may have on portfolio development. Including other potential rules is unnecessary.

The Company agrees with Joint Intervenors that transmission needs associated with new resources should be considered as part of the IRP analysis to the extent practical. While the specific transmission needs associated with any new resource cannot be known until the resource is sited and an interconnection study is performed, both of which occur downstream of the IRP, the IRP can include estimated transmission network upgrade costs for each generic resource type evaluated. Accordingly, the Company included estimated proxy costs for transmission network upgrades as part of the cost of new resources evaluated in the IRP. Other transmission and distribution system considerations, including grid reliability and resiliency issues that are not directly related to resource adequacy, have no influence on resource selection in the IRP or identification of the preferred portfolio, and therefore are not germane to the IRP analysis or proceeding.

In addition to critiques related to the scope of the IRP analysis, Joint Intervenors challenge the degree of transparency or specificity with which the Company presented its IRP. Joint Intervenors contend that the Company should have been "more transparent and specific about 'steps to be taken' in the first three years to implement the preferred plan ." While the IRP contains considerable detail on the timing and magnitude of resource changes contemplated in the Preferred Portfolio, the Company elaborates further on the steps to be taken over the next three years (between now and the filing of its next IRP in 2027) below:

- **Limestone conversion project:** upon receipt of a CPCN, the Company will perform detailed engineering studies, procure necessary equipment, and complete the project.
- **East Bend 2 Co-firing:** the Company will conduct preliminary engineering, file for modification of the air permit, file a CPCN application for the project, negotiate a gas supply agreement, perform detailed engineering, and procure major equipment. The Company will continue to closely monitor legal and regulatory

developments related to US EPA 111d, and in the event that the rule is reversed, the Company could continue to operate East Bend 2 entirely on coal into the 2030s.

- **Solar:** The Company will file the necessary permit and CPCN applications for new solar resources to be brought online by 2029 and 2031, consistent with the preferred portfolio. The Company will also begin equipment procurement.
- **Energy Efficiency and Demand Response:** the Company will continue to evaluate and pursue cost-effective tools and programs to manage growing customer load.

4. The 2024 IRP appropriately evaluated the operational life of East Bend consistent with Kentucky's energy policy.

Joint Intervenors suggest that the Company unduly constrained the IRP analysis by not evaluating retirement of East Bend 2 prior to 2032. However, this fails to consider the practical realities of developing, constructing, and interconnection equally reliable replacement generation in time to retire the unit ahead of the end of 2031, the date contemplated in the IRP. As the Company explained in response to Commission Staff data request 01-024, the lead time for a new combined-cycle (CC) generator, the cost-effective replacement for the energy and capacity provided by East Bend 2 that maintains system reliability with currently available technology, is 8 years. Given that lead time, it would not be reasonable to consider retirement of East Bend 2 prior to the end of 2031.

C. Sierra Club Comments

1. Summary of Sierra Club Comments:

The Sierra Club argues that the Company's 2024 IRP does not adequately comply with regulatory requirements for analysis and discussion of the Company's generation portfolio over the next fifteen years. The Sierra Club argues that the Company's evaluation of conversion and retirement options for East Bend is arbitrary and inadequate, concluding that the Company's DFO conversion preferred strategy is not the least-cost option and that the Company should fully convert East Bend to natural gas. Sierra Club questions the economics of East Bend and is critical of the Company's dispatch of the unit as a "must run" in PJM Interconnection LLC.'s (PJM) energy market. The Sierra Club criticizes the Company's modeling of its Limestone conversion project, currently pending before the Commission in Case No. 2024-00152, as a base assumption was unreasonable and should be tested properly, including at the revised estimated cost of $125 million, which was determined after the 2024 IRP analysis was conducted. Finally, the Sierra Club posits that fully converting East Bend from coal to gas would not trigger Kentucky law for coal retirements and would not trigger a 2039 retirement obligation under the US EPA Clean Air Act 111(d) Update (US EPA 111d).

2. The 2024 IRP complies with the Commission's regulations for IRPs and the Company's IRP analysis is reasonable.

Sierra Club's contention that the IRP fails to meet the Commission's regulations is founded in the conclusion that the Company failed to adequately evaluate alternatives to co-firing East Bend with coal and gas starting in 2030. There are several flaws in this reasoning.

First, Sierra Club argues that the Company should not have burdened analytical cases in which East Bend 2 is fully converted to natural gas fuel by 2030 with the cost of the limestone conversion project. However, at the time that forecasts and assumptions were developed for the IRP (late 2023), the economics of the conversion project were favorable in comparison to the cost of reagents that would be required without the conversion even if the unit were to stop burning coal by 2030. In other words, it would be in the best interest of customers for the Company to undertake the conversion project regardless of whether the unit would be converted to gas fuel by 2030. However, since the forecasts and assumptions were developed for the IRP, the estimated costs of conversion have increased, and the forecasted cost of reagents required without the conversion has decreased. Nonetheless, it remains true that failing to pursue the conversion project would expose customers to future cost and supply risk associated with reagent procurement in a future in which the unit continues to burn coal into the 2030s, including in the event that US EPA 111d is reversed.

In addition, Sierra Club argues that the Company's own analysis demonstrates that "both full conversion and early retirement and replacement of East Bend Unit 2 are lower-cost options than co-firing." This is incorrect. The Company is not familiar with the underlying calculations that Sierra Club used to arrive at the values provided in comments, but the numbers presented by Sierra Club do not appear to be accurate. Table 1 below provides a summary of the present value of revenue requirements (PVRR) for each of the optimized and alternate portfolios presented in the IRP. These numbers are also provided in charts in IRP Section 6.

Table 1: PVRRs for Optimized and Alternate IRP Portfolios with and without US EPA 111d ($MM)

	With US EPA 111d	Without US EPA 111d
Optimized Portfolios		
East Bend DFO Conversion by 2030	$2,592	$2,523
East Bend Natural Gas Conversion by 2030	$2,629	$2,616
East Bend Retirement by 2032	$2,618	N/A
East Bend Retirement by 2036	N/A	$2,340
Alternate Portfolios		
East Bend DFO Conversion with CC Replacement by 2039	$2,667	$2,592
East Bend DFO Conversion with SMR Replacement by 2039	$2,677	$2,607
East Bend DFO Conversion with CC with CCS Replacement by 2036	$2,499	N/A
East Bend DFO Conversion with CC Replacement by 2036	N/A	$2,631
East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables	$2,669	$2,592
East Bend Retirement by 2032 with CC Replacement	$2,753	N/A

East Bend Retirement by 2036 and Accelerated Renewables	N/A	$2,512
East Bend Retirement by 2042	N/A	$2,442

Note: DFO = dual fuel optionality, indicating coal/gas co-firing; SMR = small modular reactor; CCS = carbon capture and sequestration

"East Bend DFO Conversion with CC Replacement by 2039 and Accelerated Renewables" (PVRR Table 1) is the preferred portfolio for the 2024 IRP. If US EPA 111d is reversed, a portfolio more like "East Bend Retirement by 2036 and Accelerated Renewables" (PVRR shaded Table 1) would be preferred.

As the PVRR results in Table 1 illustrate, the optimized DFO portfolio has a lower PVRR than the optimized Natural Gas Conversion portfolio in scenarios with and without US EPA 111d and has a lower PVRR than the optimized Retirement portfolio in the scenario with US EPA 111d. While the EnCompass capacity expansion model selected a CC with CCS as the replacement for East Bend 2 in the optimized DFO and Retirement portfolios, but the Company concluded that CCS technology has not achieved a level of maturity sufficient to form the basis of the preferred portfolio.[8] In the absence of a CC with CCS as a replacement resource option, the natural gas conversion portfolio does have a slightly lower PVRR. However, as explained in Section 6 of the IRP, co-firing (DFO) provides fuel flexibility, which is particularly valuable in this period of regulatory and fuel market uncertainty, and "allows time for technologies such as CCS and SMRs to evolve and potentially be considered as replacement options for East Bend in the late 2030s."[9]

In addition to arguments related to co-firing and gas conversion of East Bend 2, Sierra Club contends that the Company used unreasonable forecasts for the cost of replacement resources, particularly renewable energy, and energy storage. In support of this argument, Sierra Club

[8] IRP pg. 56.
[9] IRP pg. 57.

references capital cost forecasts in the National Renewable Energy Laboratory's (NREL) 2024 Annual Technology Baseline (ATB). However, the 2024 NREL ATB was initially published on June 25, 2024, which was three days after the IRP was filed, and could not have been considered in the development of the IRP.[10] The IRP must be developed using what the Company judges to be the best information available at the time, and obviously cannot be informed by data published after the analytics have been conducted, never mind data published after the IRP is filed. Without commenting on the validity of the 2024 NREL ATB, the Company stands by the forecasts and assumptions used in the 2024 IRP and notes that they are generally consistent with cost assumptions used in other recent Kentucky utilities' IRPs.[11]

3. The Company's proposed DFO conversion of East Bend is reasonable and consistent with Kentucky energy policy.

The Company's preferred portfolio that includes converting East Bend to DFO co-firing is reasonable and consistent with Kentucky energy policy which is indisputably aimed at prolonging the useful and economic life of coal and fossil generation. The Company's portfolio analysis takes into consideration known environmental regulations, particularly the US EPA 111d and associated compliance deadlines to determine the least cost and reasonable solutions for meeting customer energy needs over the planning horizon. KRS 278.264 establishes a rebuttable presumption against the retirement of dispatchable fossil generation unless a utility can meet the statutorily created burden against that presumption. The Sierra Club fails to identify or provide any analysis that would support that Kentucky's rebuttable presumption against retirement is met such that an earlier retirement can be justified under Kentucky law. The Sierra Club only raises foundationless

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[10] https://atb.nrel.gov/electricity/2024/errata

[11] *See e.g., Case No. 2024-00326, 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company Volume 1, Table 6-4.; and Case No. 2022-00353, Kentucky Power 2022 Integrated Resource Plan, Volume A (dated March 20, 2023), Figures 14, 15, 18, and 22.*

hypothesis. The Company's IRP analysis is based upon reasoned analysis, informed by Federal environmental legislation as it existed at the time the IRP was prepared. The Commission will have the ability to review the Company's compliance strategies when it files the required retirement approvals in a subsequent case. Deciding this strategy now is simply premature and speculative.

4. The Company's use of both a "Must Run" and "Economic" commit status offer for East Bend is reasonable and in the best interests of customers. The Sierra Clubs description of East Bend being an [redacted] unit is false.

The Sierra Club states that "East Bend Unit 2 is already [redacted] to operate and has been for several years because, among other things, [redacted], let alone its fixed or capital expenses." Sierra Club further alleges that Duke Energy Kentucky "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."[12] These claims are false. In making these statements, the Sierra Club either does not understand the data supplied or is intentionally misusing it. The Sierra Club has cherry picked certain years to enhance their analysis, and in doing so has demonstrated its lack of understanding of the PJM market and characteristics of a coal-fired generator, is engaging in an improper hindsight review, and ignores any impact to East Bends capacity value from excessive unit cycling. The Company's current operation of East Bend results in significant cost savings and benefits to the Kentucky customer.

Although there are many components of a generating unit's supply offer in the PJM market, the commit status offer can be one of four choices: 1) Economic; 2) Emergency 3) Must Run; or 4) Not Available. If a status of "Economic" is used, PJM decides if the unit will operate or not

[12] *Sierra Club Comments* pg. 2.

(*i.e.,* its "commitment"). If a status of "Must Run" is used, the Company determines that unit will operate, but PJM decides the energy output of the unit between its minimum possible output and its maximum possible output (*i.e.,* its "dispatch"). If a status of "Emergency" is used, the unit can only be committed in an emergency. Finally, if a status of "Not Available" is used, the unit cannot be committed since it is outage.

Each day, by 11:00 AM EPT, Duke Energy Kentucky submits an offer for East Bend into the PJM Day-Ahead Energy Market, as well as continuously updating the units offer every hour in the Real-Time Market. The Company's commitment decision is not simply a random and uninformed decision, but is based upon numerous factors and detailed data-driven analysis including, but not limited to, demand and weather forecasts, fuel and energy pricing forecasts, the unit's operating characteristics (how fast it can start, ramp up, etc.), any known or emerging operating constraints, risks of taking the unit offline and not having it available when needed, and the ability to hedge the customers power market price exposure. The Day-Ahead offer process begins with a 6:30 AM meeting attended by station and generation dispatch personnel, where a discussion of customer demand, weather forecast, natural gas prices, expected Day-Ahead and actual Real-Time energy market prices, unit availability, the status of any issues that may present increased risk to the unit's availability, and any needed testing or other operating constraints are discussed. In addition, generation dispatch personnel may then discuss any expected changes in a unit's commitment status. Although Duke Energy performs other planning for generating unit operations over a longer time horizon, for purposes of determining the commitment status of East Bend, this process looks out over the next 1-2 weeks.

When participating in PJM, it is important for a generation owner to understand the financial impact of operating its generating units in the energy market. To accomplish this, the

Company creates a Daily Profit & Loss Analysis (Daily P&L) each business day. This Daily P&L is one input used in the determination of the units PJM Commit Status offer. This analysis projects expected operating margins (revenues minus variable costs) from operation of East Bend for the next 21 days based on the unit's offer price, operating parameters and expected energy market Locational Marginal Price (LMP) forecast. The economic analysis is done over this timeframe to account for factors that may not be represented in the PJM Day-Ahead Energy Market, which is one day into the future, such as unit cycling costs. Operating parameters include aspects that define the unit, such as the generator's minimum load and maximum load. Energy market prices are based on forecasted or observed trades for AEP-Dayton Hub LMP prices, adjusted for congestion and losses between the hub and the East Bend node. Finally, the units offer is calculated using a fuel price multiplied by the unit's efficiency (heat rate), plus variable O&M and emissions variable costs. For creating the units offer, it is important to note that the replacement or market value of the coal being consumed is used for the units offer, not the accounting price of the coal being consumed. In the Sierra Club economic analysis, they failed to understand the difference between the coal price used for commitment and dispatch purposes (the market price of coal) and the actual coal cost burned in the unit (the accounting cost of coal).

In addition to understanding the expected economic value or loss from operating a unit, the Daily P&L analysis is used to understand and deal with the consequences of the different time horizons that typically exist between the next day, 24-hour PJM Day-Ahead market, and the unit's minimum run time. A coal unit is typically committed for a period longer than its minimum run time due to the economics of overcoming the startup cost and shutdown cost hurdle. The practical commitment period, considering these factors, is typically at least a week. The PJM Day-Ahead and Real-Time energy markets frequently do not optimize the commitment of a coal unit due to time it takes to start-up and the hurdle rate (cycle costs) required to start or shut down a unit. Commitment decisions involve many different inputs, including the initial state of the unit (on or off), expected revenue from operation of the unit, operating cost of the unit including replacement fuel cost, unit startup up cost, unit startup up time, risk around cycling off-line, minimum up and down times, the need to perform any required unit testing, weather and system reliability conditions and other factors. When available, Duke Energy Kentucky's coal unit, East Bend, is typically offered into the PJM Day-Ahead Market with a Must Run offer status to best optimize the unit's availability for dispatch in PJM since it is typically in the money to operate, meaning that the expected revenues received from PJM are greater than the market fuel, variable O&M, and emissions costs of the unit. However, if during non-winter months (December, January, and February), expected revenues from running the unit are expected to be less than the units' variable costs, the unit may be offered as Economic to PJM to allow PJM to determine the commitment decision for the unit since it makes economic sense to do so.

The Sierra Club's comments fail to consider any of the factors the Company considers as part of its commitment decisions and thus, the Sierra Club's conclusions are uninformed and should be ignored entirely by the Commission. The Sierra Club had the opportunity, but did not bother to inquire into how the Company makes its dispatch decisions at the time those decisions are made. However, these reports were not requested. Admittedly, while there are times when East Bend is out of the money or projected to have revenues less than the units projected variable cost, Duke Energy Kentucky may still commit the unit as Must Run. This can occur for several reasons, including but not limited to, 1) avoid an uneconomic cycle such as over a weekend; 2) accomplish unit testing; 3) incorporate additional risk factors such as PJM Capacity Performance periods, or 4) the ability to hedge the customer power price exposure. Duke Energy Kentucky's team of individuals that determine the best commitment strategy each day work to determine the optimum generating unit offer for the benefit of our customers and in doing so, consider the realities of the 24 hour PJM market compared to the longer commitment period necessary for a coal-fired generator, forecasts of weather, price, costs, while recognizing the risks from uneconomic cycling of the unit, and any required operation such unit testing.

The Sierra Club argues that by offering East Bend as Must Run, the Company is acting imprudently. As previously explained, the Must Run decision is not uninformed or made in a vacuum. Moreover, always offering the unit with an Economic commitment status, as the Sierra Club would have the Company do, includes risks that can either cause the unit to not be started when it should operate, cause excessive cycling costs and potential damage, and may shut down the unit when it is economic to leave the unit on-line over the longer term. Again, this is due to the planning horizon of the PJM Day-Ahead market (24 hours) in relationship to the unit's practical minimum up time, minimum down time, and/or startup time. As a base-load coal-fired generator, East Bend cannot respond quickly to changes in power prices on an hourly or daily basis when a unit is cycled off because of an Economic commitment offer. For this reason, PJM may not call upon the unit in the Day-Ahead Market because the unit cannot power up quickly enough in an offline state, even if it is otherwise economic to operate. This could result in the unit and in turn customers, missing significant value in the market and being exposed to additional purchased power expense.

In addition, unit cycling and resulting performance must be considered. For example, if the units were frequently cycled from off-line to on-line, the risk of error, damage, and unit degradation increases. Failed start-up due to risks of thermal cycling could occur in this scenario, resulting in additional cost of repair, lost energy margins during the time that the unit was off-line for repair, and any additional PJM charges, *i.e.,* potential capacity performance charges. These factors are prudently evaluated when considering de-commitment into Reserve Shutdown for East Bend.

The Sierra Club Comments, including its Figure 3, is misleading and implies that the Company rarely offers East Bend with a commit status of Economic, since the unit was offered as Economic between 2% and 4% of the time it was available in 2022 thru 2024 (YTD). However, the data produced is self-serving and intentionally did not include 2020, when during low market prices due to COVID, the unit was offered as Economic and was decommitted by PJM for 57 days during the spring of 2020 and was additionally on reserve shutdown for 19 days in January of 2020 due to a mild stretch of weather starting in late January; thus, during 2020, the unit was offered with an Economic commit status offer over 25% of the available hours in 2020 . Please refer to Case No. 2024-00197, AG-DR-02-003 Attachment 2.

The Sierra Club also fails to understand how the Company takes advantage of low market priced periods to perform maintenance on East Bend to get the unit ready for times when market prices are anticipated to be higher in the future. During these lower-priced periods, the unit is out of the money and could have been just left off-line on reserve shutdown, but the Company elected to use this period to perform maintenance and the unit status was changed to unavailable; thus, these instances will never show up in the Sierra Club data. In the Company's response to data response AG-DR-02-003, the Company was asked to provide the hourly offer (commit status) information for East Bend utilized in the PJM energy market. In this response, if the unit is unavailable in an hour, the hourly offer to PJM shows "Not Available." The calculations that the Sierra Club utilized in the creation of Figure 3 fail to understand this nuisance and the Company receives no "credit" here, since the Sierra Club calculations only examine hours in which the unit is offered as either "Must Run" or "Economic" and doesn't include the impact of economic shutdown when the unit is unavailable. In fact, this very situation is occurring as this document is written. During November of 2024, due to low PJM energy market prices, East Bend was out of the money, offered to PJM as “Economic”, and removed from service. However, in recognition of the need for maintenance that can be performed while the unit was not economic to serve customers, the station made a request to the dispatch group, and the dispatch group coordinated with PJM, a change in the units commit status offer from “Economic” to “Not Available” so that this additional maintenance could be completed prior to forecasted cold weather returning to the Midwest the week of and immediately following the Thanksgiving holiday. This tactic is frequent utilized by the Company, since the best time to perform maintenance for a unit is when it is not needed. Although the Company is unable to determine the amount of time it utilized economic shutdown time periods to perform this maintenance, the following table shows the potential impact of this strategy.

East Bend Hourly PJM Commit Status Offer Summary

	Hours Offered with PJM Commit Status of Must Run	Hours Offered with PJM Commit Status of Unavailable	Hours Offered with PJM Commit Status of Economic
2021*	5,166	3,559	35
2022 **	6,251	2,245	264
2023 **	5,661	2,935	164
2024 YD August **	5,855	898	248

	Percent of Time Offered with PJM Commit Status of Must Run	Percent of Time Offered with PJM Commit Status of Unavailable	Percent of Time Offered with PJM Commit Status of Economic
2021	59%	41%	0%
2022	71%	26%	3%
2023	65%	34%	2%
2024 YD August	84%	13%	4%

	Percent of Time Unit Available Offered with PJM Commit Status of Must Run	Percent of Time Unit Available Offered with PJM Commit Status of Economic
2021	99%	1%
2022	96%	3%
2023	97%	2%
2024 YD August	96%	4%

* Data from Case No. 00012, STAFF-DR-02-021(a) CONF Attachment
** Data from Case No. 00197, AG-DR-02-003 Attachment 1
Historica data for 2020 and prior unavilable due to change in offer software vendor

Sierra Club Figure 2 utilizes data supplied by the Company in the response to KSES-DR-01-002 and is basis for their determination that "East Bend Unit 2 is already [redacted] to operate…"[13] The Sierra Club use of this data is deeply flawed for several reasons because they: (1) "cherry-picked" the lowest market priced two years and ignored the energy value created by the unit in other years; (2) used accounting costs for coal instead of the market price of coal, (3) ignored ancillary service value, and (4) failed to consider impacts to the unit's capacity value from

[13] *Sierra Club Comments* pg. 2.

excessive unit cycling. As evidence of "cherry-picking data" the Sierra Club's Confidential Figure 2 focuses on East Bend's fuel costs and energy market revenues for the only two years. However, as the Commission is aware, energy and commodity prices have been volatile, with energy and commodity prices peaking during 2021 and 2022, and lows reached in 2020 due to COVID. If all the data from KSES-DR-01-002 is included instead of just the two cited by the Sierra Club, the results are remarkably different and are as follows:

[redacted]

East Bend Unit 2	PJM Energy Market Revenue ($)	Fuel Costs ($)	Unit Margin ($)
2018	$ 89,368,125	$ 57,890,073	$ 31,478,052
2019	$ 80,764,631	$ 67,767,903	$ 12,996,728
2020	$ 51,214,368	$ 50,256,155	$ 958,213
2021	$ 83,491,681	$ 54,171,470	$ 29,320,211
2022	$ 203,779,804	$ 79,902,243	$ 123,877,561
2023	$ 70,944,881	$ 85,370,908	$ (14,426,027)
YTD 2024 (thru July)	$ 49,872,147	$ 53,561,267	$ (3,689,120)
Total	$ 629,435,637	$ 448,920,019	$ 180,515,618

The unit's performance that the Sierra Club points to for their position were the only years in the last six and a half in which a net [redacted] unit margin was received. If all six and a half years of data are considered, East Bend has produced over $[redacted] for the Duke Energy Kentucky customer from energy market value created from operating the unit. As was previously discussed, the Company uses the market price of coal in its PJM offer, not the accounting coal cost of the unit. Using accounting coal is obviously proper in a fuel adjustment clause (FAC) proceeding for calculation of customer rates, but to examine the effectiveness of the Company's supply commit status offer, using accounting cost instead of the actual fuel price used in the units PJM offer is a comparison of apples to oranges. As stated earlier, the Company's Daily

P&L Analysis is a better and more accurate analysis of the unit's performance in relation to the Company's commitment decisions, which among other things, includes the market price of coal, not accounting coal costs.

Another reason the Sierra Club Figure 2 does not present an accurate picture of the East Bend's value is that it does not consider the Ancillary Services revenues that East Bend provides for customers. Although the Company is unable to separate ancillary services revenues between those received by East Bend and those received by Woodsdale, nonetheless, these revenues do provide some potential additional value. Finally, the Sierra Club's analysis does not consider an impact to East Bend's total capacity value from excessive cycling that could result from excessive use of an Economic commit status offer. As the Commission is aware, the Company currently participates in the PJM Fixed Resource Requirement (FRR) capacity construct, not in the Reliability Pricing Model (RPM). The Company has been an FRR participant since first joining PJM. Since the Company is an FRR participant, it only receives capacity revenue *after* the Company has provided the capacity needed to serve its customers in its FRR plan. Thus, any capacity revenue received today is received after first serving the customers need and the required FRR holdback and does not represent the true capacity value of East Bend. At the current bilaterial capacity price of approximately $250/MW-Day, the additional avoided capacity cost from East Bend is approximately [redacted] per year. Although the PJM capacity and energy markets are separate markets, they are linked since a unit's performance in the energy market can impact the units value in the capacity market. Thus, if a generator owner used an excessive Economic commit status offer and as a result, the unit cycled on and off frequently, due to multiple additional startups, it is natural that decreased unit performance can result as well as increased exposure to capacity performance penalties. Since a generators capacity value is determined by its Effective Load

Carrying Capability (ELCC) value adjusted for performance within its class, this increase in forced outage rate would leave to a reduction in capacity value, which as shown, is becoming increasingly valuable in the PJM capacity market.

Finally, the Sierra Club's position that the Company should only commit the unit as Economic is flawed as it fails to acknowledge PJM's Capacity Performance construct and the risk of significant penalties. As stated earlier, the Company may offer East Bend as Economic, allowing PJM to decommit the unit, during non-Winter months. However, the risk profile during the Winter months of December, January, and February has not historically justified an Economic offer to PJM. Any additional small value received from decommitting East Bend during winter is simply not worth the risk of either PJM Capacity Performance penalties or the potential lost opportunity from being off-line. This position is buttressed by the significant capacity performance penalties levied by PJM after Winter Storm Elliott.

Finally, it should be noted that, in the IRP, the Company modeled East Bend as "Must Run" during winter months (December, January, and February) when coal was part of the fuel mix for East Bend. However, this assumption was not modeled in the Natural Gas Conversion case. In reality, given the time to start up the facility, even when converted to 100% natural gas, the Company may decide to commit the unit as Must Run to avoid the risk of penalties noted above and to avoid the risk of the unit being unavailable or unable to start up when needed. This conservative modeling assumption does, improve the value of the NGC case compared to the other portfolios modeled in the IRP.

5. The Sierra Club's claim that fully converting East Bend to natural gas would not trigger Kentucky law for coal retirements is not accurate.

The Sierra Club's claim that full conversion of East Bend to operate on natural gas would not trigger compliance obligations as the unit is not being retired is legally untested and likely inaccurate as it ignores fundamental accounting principles and the operational characteristics and differences of a coal-fired unit and natural-gas-fired unit.[14] As this Commission is aware, Kentucky energy policy shifted in 2023, with the passage of Senate Bill 4, the enactment of KRS 278.264 and the requirement of a utility to receive Commission approval before retiring any fossil-fueled unit and the creation of the rebuttable presumption *against* retirements of fossil generation in the Commonwealth, especially coal-fired units. KRS 278.264(2) provides in relevant part:

> There shall be a rebuttable presumption against the retirement of a fossil fuel-fired electric generating unit. The commission shall not approve the retirement of an electric generating unit, authorize a surcharge for the decommissioning of the unit, or take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption created by this section is rebutted by evidence sufficient for the commission to find that:
>
> a) The utility will replace the retired electric generating unit with new electric generating capacity that:
>   1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
>   2. Maintains or improves the reliability and resilience of the electric transmission grid;
>   3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and
>   4. Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service;
>
> b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law;
>
> c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency; and
>
> d) The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier.[15]

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[14] Sierra Club Comments pg. 20.

[15] KRS 278.264

This policy was further cemented with 2024's passage of Senate Bill 349 and the creation of the Energy Planning and Inventory Commission (EPIC). In summary, SB 349 prohibits a utility from retiring an existing coal, oil, or natural gas-fired power plant, or a generating unit within the plant, prior to submitting notice to the newly created EPIC and receiving the Committee's findings on the proposed retirement. A utility must submit notice of the proposed retirement to EPIC at least 180 days prior to submitting an application to the Commission to retire the plant or unit. Any retirement application to the PSC will not be deemed administratively complete unless it includes either the Committee's final report or evidence that more than 180 days have passed since notice was submitted to the Committee and no Committee report or determination has been provided to the utility.[16]

As the Commission is aware, East Bend is Duke Energy Kentucky's single-base load generating source and is a coal-fired unit. The full conversion of the unit to natural gas would mean that the portions of the unit that are dedicated solely to enable the use of coal as a fuel would need to be taken out of service and retired. Safety, engineering requirements, and accounting would necessitate the retirement and decommissioning of these assets upon conversion from fuel to gas. Conversion to gas would require the removal, and retirements of coal-specific facilities including, but not limited to, coal yard equipment, grinders, conveyors, coal-specific environmental compliance facilities such as landfills, harbor facilities used solely for unloading of coal and coal-specific environmental reagents, and reagent storage facilities. It would be imprudent to simply "mothball" such facilities for an indefinite period as without proper maintenance and upkeep, these facilities could create hazards. These assets, which are not fully depreciated, upon their removal,

[16] KRS 164.2807

disconnection, or decommissioning, would create a stranded cost once they become no-longer used and useful. Accounting principles would necessitate these assets, to the extent no longer used, be "retired" on the books and deferrals would be necessary or else the Company would face significant write-offs and financial losses. Again, under KRS 2789.264, the Company could not even request such assets be created under KRS 278.264, without first providing notice to the EPIC and then seeking Commission authorization in accordance with KRS 278.264 by meeting the rebuttable presumption. Therefore the Sierra Club's position that a conversion for East Bend would not trigger any need to seek Commission authorization, or trigger retirement implications under Kentucky law is a narrow reading of the law that is untested, self-serving, and most likely inaccurate as it ignores the accounting implication of such a conversion.

IV. Conclusion

For the foregoing reasons, the Commission should recognize the self-serving nature of comments of the Sierra Club, and Joint Intervenors and ignore or reject them outright. The Company's 2024 IRP was thorough, consistent with prior IRP analysis accepted by the Commission, and presents a reasoned and well thought plan for meeting Duke Energy Kentucky's customers' energy needs over the long-term in the least-cost, most reasonable manner.

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document in paper medium; that the electronic filing was transmitted to the Commission on November 27, 2024; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that submitting the original filing to the Commission in paper medium is no longer required as it has been granted a permanent deviation.[17]

/s/Rocco D'Ascenzo

Rocco D'Ascenzo

[17] *In the Matter of Electronic Emergency Docket Related to the Novel Coronavirus COVID-19,* Order, Case No. 2020-00085 (Ky. P.S.C. July 22, 2021).