COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR (1) AN ADJUSTMENT OF ELECTRIC RATES; (2) APPROVAL OF NEW TARIFFS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (4) ALL OTHER REQUIRED APPROVALS AND RELIEF	))))))))	**Case No. 2022-00372**

SIERRA CLUB'S POST HEARING BRIEF

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INTRODUCTION

In this proceeding, Duke Energy Kentucky ("Duke" or "the Company") seeks to mitigate risk for its customers by aligning the depreciation rate for East Bend Unit 2 ("East Bend") with the unit's anticipated retirement date. This goal is in accordance with fundamental principles of ratemaking, that depreciation should be aligned with a unit's projected retirement in order to ensure only customers who benefit from the unit pay for the unit. But the anticipated retirement date that Duke has proposed in this proceeding is not, in fact, the most likely retirement date for East Bend. Duke's own modeling in its 2021 integrated resource plan ("IRP") shows that East Bend is most likely to become uneconomic for customers in the mid-2020s and that Duke can retire and replace East Bend by 2030. Developments since the IRP, including the passage of the Inflation Reduction Act ("IRA") and the introduction of significant federal environmental regulation, reinforce that the scenarios in the IRP with a mid-2020s economically optimal retirement date are most likely. Sierra Club's expert witness's analysis also demonstrates that Duke's modeling assumes unrealistically low operating and maintenance costs for East Bend and, in no-carbon regulation scenarios, an unrealistically high capacity factor. In fact, Sierra Club's expert witness shows that East Bend is projected to be uneconomic on a going-forward basis.

In short, the evidence in this proceeding demonstrates that East Bend will become uneconomic no later than the mid-2020s and can feasibly be replaced by 2030. The Commission should align depreciation with that projected date. Doing so is consistent with the Commission's regular practice and is all the more important in light of Kentucky's new law, SB 4, which could make retirement more difficult if substantial net book value remains at the date of retirement. Planning ahead for retirement consistent with SB 4 is necessary to mitigate risk to customers, which would arise if Duke were unable to retire East Bend as an uneconomic and likely increasingly unreliable asset. Moreover, while 2030 is the most likely retirement date based on information at this time, the IRA and federal environmental regulation may make an earlier date more probable, and they provide necessary insights for Duke in planning for a post-East Bend future. The Commission should require Duke to engage in analysis of the IRA and the cumulative effects of federal regulation in its next IRP and to return to the Commission with a new rate case if the anticipated retirement date shifts again. This analysis should also examine reliability.

In addition to the proposed alignment of depreciation with a new retirement date for East Bend, Duke proposes new tariff rates to incentivize off-peak charging for electric vehicles. The Commission should adjust these proposed rates as Sierra Club's expert witness recommended, in order to ensure that they best incentivize off-peak charging that decrease rates for all customers and, more importantly, spread load in a manner that minimizes additional grid investments.

LEGAL STANDARD

The ultimate standard for setting utility rates is whether rates for customers are "fair, just, and reasonable."[1] An important factor in determining "fair, just, and reasonable" rates is whether an electric generating unit is "'used and useful' for the benefit of" customers.[2] Generally, a utility should be authorized to charge only the "lowest reasonable rate" that allows the utility to "operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed even though they might produce only a meager return on the so-called 'fair value' rate base."[3]

[1] K.R.S. § 278.030(1). *See In re: Elec. Application of Big Rivers Elec. Corp. for Approval to Modify Its Mrsm Tariff, Cease Deferring Depreciation Expensises, Establish Regul. Assets, Amortize Regul. Assets, & Other Appropriate Relief*, No. 2020-00064, 2020 WL 3512155, at *11 (Ky. P.S.C. June 25, 2020).

[2] *In re: Elec. Application of Big Rivers Elec. Corp. for Approval to Modify Its Mrsm Tariff, Cease Deferring Depreciation Expensises, Establish Regul. Assets, Amortize Regul. Assets, & Other Appropriate Relief*, No. 2020-0064, 2020 WL 3512155, at *11 (Ky. P.S.C. June 25, 2020).

[3] *Comm. Ex rel. Stephens v. South Cent. Bell Tel. Co.*, 545 S.W. 2d 927, 931 (Ky. 1976) (citing *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944)).

Jurisdiction lies "exclusively and primarily" with the Commission to "fix rates [and] establish reasonable regulation of service."[4] In these proceedings, the utility bears the burden of proof that its proposed increased rates would be fair, just, and reasonable.[5]

ARGUMENT

I. The Commission Should Align Depreciation with an Anticipated Retirement Date of 2030 for East Bend.

The Commission regularly aligns depreciation with a unit's anticipated retirement date, to ensure that the same customers who enjoy the benefits of an asset are also paying the costs of that asset. As Duke has stressed throughout these proceedings, that anticipated retirement date is the *most likely* retirement date based on an uncertain future.[6] Such alignment is appropriate here, and the most likely retirement date is 2030. This conclusion is based on Duke's own modeling in the 2021 IRP, which found that in scenarios with carbon regulation and a base or low gas rate the economically optimal retirement date is 2027. This date is confirmed by Duke's testimony in these proceedings, which states that the IRA is a form of carbon regulation and that 2030 is currently the earliest feasible retirement date for East Bend for the utility. The 2030 date is further confirmed by Ms. Shenstone-Harris's modeling and her evaluation of Duke's modeling, which concludes that Duke has overestimated likely future capacity factors for East Bend and has underestimated projected operation and maintenance costs. Moreover, the proposal of federal environmental regulation and the passage of Kentucky's SB 4 all indicate that an earlier anticipated retirement date is warranted. Failure to adjust depreciation to an anticipated retirement date of 2030 would cause

[4] *Pub. Serv. Comm'n of Ky. v. Comm. of Ky.*, 320 S.W. 3d 660, 665 (2010).
[5] K.R.S. § 278.190(3).
[6] *E.g.*, Park Reb. Test. at 19:9-12 ("A prudent decision needs to include risk-informed economic analysis. Since the future is uncertain, a prudent decision needs to be informed by what the Company thinks is most likely to happen, based upon robust modeling and analysis.").

not only economic but also reliability risks for customers: as East Bend becomes less economic, it is likely to also become less reliable.

A. This Commission's Regular Practice, and a Fundamental Principle of Ratemaking, is to Align Depreciation with Anticipated Retirement Date.

Sierra Club agrees with Duke that aligning depreciation with East Bend's anticipated retirement date is appropriate to ensure intergenerational equity. Such alignment of depreciation and the anticipated useful life of East Bend is consistent with Kentucky law and the Commission's past practice. As discussed above, the ultimate standard for this rate case is whether rates for customers are "fair, just, and reasonable,"[7] and an important factor to that determination is whether an electric generating unit is "'used and useful' for the benefit of" customers.[8] This is because "our public policy, statutes, and cases clearly seek to protect consumers from paying for facilities which do not benefit them."[9]

The Commission regularly employs the concept that a generating unit must be "used and useful" to customers and, accordingly, seeks to align depreciation with retirement. For example, in Duke's recent gas case seeking approval for its Rider Pipeline Modernization Mechanism, the Commission expressed concern that "[t]o the extent that pipeline being replaced is not fully depreciated, such a failure could result in Duke Kentucky earning a return on plant that is no longer in service."[10] In another recent case, the Commission explained that "the closure date" of a

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[7] K.R.S. § 278.030(1). *See In re: Elec. Application of Big Rivers Elec. Corp. for Approval to Modify Its Mrsm Tariff, Cease Deferring Depreciation Expensises, Establish Regul. Assets, Amortize Regul. Assets, & Other Appropriate Relief*, No. 2020-00064, 2020 WL 3512155, at *11 (Ky. P.S.C. June 25, 2020).

[8] *In re: Elec. Application of Big Rivers Elec. Corp. for Approval to Modify Its Mrsm Tariff, Cease Deferring Depreciation Expensises, Establish Regul. Assets, Amortize Regul. Assets, & Other Appropriate Relief*, 2020 WL 3512155 at *11.

[9] *Nat'l-Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 785 S.W. 2d 503, 511 (Ky. Ct. App. 1990).

[10] *In re: Elec. Application of Duke Energy Ky., Inc. for an Adjustment to Rider PMM Rates and for Tariff Approval*, No. 2022-00229, 2023 WL 3750627, at *4 (Ky. P.S.C. May 26, 2023).

generating unit "would guide a decision regarding the appropriate depreciation rate."[11] In a related vein, in a request for information in 2015 with respect to East Bend, Commission staff noted that "asset retirement costs are to be depreciated over the useful life of the related asset."[12]

The underlying idea is that existing customers who will be able to take advantage of the resource should pay for that resource, rather than future customers who are not receiving a benefit. The Commission followed this principle in a 2018 decision on Duke's electric rates, finding that Duke's "treatment of terminal net salvage value in computing the depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved."[13] In other cases, as well, the Commission has recognized the importance of avoiding intergenerational inequity. For example, in a 2004 case the Commission included the net cost of removal in depreciation rates, justifying this decision on the basis of "a desire to match an asset's cost with the ratepayers who receive its benefit (and thereby avoiding intergenerational inequities)."[14] The Commission explained, "Requiring ratepayers to pay for costs of an asset when they received no benefit from that asset creates intergenerational inequities."[15]

In short, as the Minnesota Public Utilities Commission recently explained, and as this Commission's approach reflects:

> As a capital asset is used in operations, it contributes, either directly or indirectly, to an entity's cash flows. Depreciation is a cost allocation method that allows an entity to

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[11] *In re: Elec. Application of Ky. Power Co. for Approval of A Certificate of Pub. Convenience & Necessity for Env't Project Constr. at the Mitchell Generating Station, an Amended Env't Compliance Plan, & Revised Env't Surcharge Tariff Sheets*, No. 2021-00004, 2022 WL 1489354, at *4 (Ky. P.S.C. May 3, 2022).

[12] *In re: Application of Duke Energy Ky., Inc. for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated With Ash Pond Asset Retirement Obligations*, No. 2015-00187, 2015 WL 4866387, at *1 (Ky. P.S.C. Aug. 10, 2015).

[13] *In re: Elec. Application of Duke Energy Ky., Inc. for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief*, No. 2017-00321, 2018 WL 1844249, at *16 (Ky. P.S.C. Apr. 13, 2018).

[14] *In re: Louisville Gas & Elec. Co.*, Nos. 2003-00433 and 2003-00434, 2004 WL 1898480, at *1 (Ky. P.S.C. Aug. 12, 2004).

[15] *Id.*

> approximately match the revenues generated by an asset with the cost of the asset over its useful life. It follows then that an asset's depreciable life and corresponding depreciation rate should generally align with the time period in which the asset is used and useful.[16]

Thus, to determine the appropriate depreciation rate and to ensure that depreciation is aligned with retirement, it is essential that the Commission determine the anticipated retirement date of the generating unit. Because this exercise involves predicting the future, doing so is, of course—as Duke has emphasized throughout this proceeding—a question of probability, or what is the *most likely* retirement date for the unit.[17] The most likely retirement date for East Bend based on all available information is 2030, as described below. And, as described below, any uncertainty should be resolved in favor of estimating an earlier retirement date, in order to ensure that Duke Energy customers are not paying intergenerationally for East Bend and are being charged only "fair, just, and reasonable" rates.

B. The Most Likely Retirement Date for East Bend is No Later than 2030, *not* 2035.

The record demonstrates that no later than 2030—*not* 2035, or later—is the most likely, or anticipated, retirement date for East Bend. In fact, 2030 is the anchoring date that Duke itself has repeatedly used, and 2035 represents not the most likely scenario but rather an outer bound on the edge of feasibility. That 2030 is the most likely date is evident from both Duke's IRP and testimony from Duke witnesses in these proceedings. And the probability that East Bend becomes uneconomic to operate in 2030 or at an earlier date has only increased with the passage of the IRA and the introduction of new federal regulation. Duke has characterized the resource planning that is required as needing to choose the most prudent path for the most likely scenario. It is most likely

[16] *In re: Petition of Northern States Power Co. d/b/a Xcel Energy for Approval of the Annual Update of Remaining Lives and Depreciation Rates for Transmission, Distribution, and General Accounts*, 2022 WL 2817950 at *4 (Minn. P.U.C. July 12, 2022).

[17] *E.g.*, Park Reb. Test. at 19:9-12 ("A prudent decision needs to include risk-informed economic analysis. Since the future is uncertain, a prudent decision needs to be informed by what the Company thinks is most likely to happen, based upon robust modeling and analysis."); *id.* at 23:2-3 ("The goal of rate-making should be to align the depreciable life of the asset with its most likely service life.").

that East Bend becomes uneconomic to operate before 2030, and Duke has identified 2030 as the earliest feasible date for retirement. Thus, the most likely scenario is that East Bend retires in 2030.

1. Duke's IRP Demonstrates That 2030 is the Most Likely Retirement Date for East Bend.

Duke's most recent IRP, filed with the Commission in 2021, itself identifies the 2020s as the most likely time for the end of the economic useful life of East Bend. The 2021 IRP evaluates six different portfolios economically optimized through modeling.[18] Those portfolios are the result of Duke's modeling of six different scenarios, based on two sensitivities: carbon regulation and gas price.[19] Duke modeled scenarios with carbon regulation, and scenarios without carbon regulation.[20] In each category—with and without carbon regulation—Duke modeled scenarios with a range of three gas price sensitivities—high, medium, and low.[21] This modeling led to the following economic retirement dates for East Bend:[22]

IRP Scenarios with Carbon Regulation

Gas Price	East Bend 2 Retirement Date
High	2035
Base	2027
Low	2027

IRP Scenarios without Carbon Regulation

Gas Price	East Bend 2 Retirement Date
High	2035 [stated in testimony to be a typo, and to be beyond 2035[23]]
Base	Beyond 2035
Low	2025

[18] Ex. SC-1 (Duke Energy, *Duke Energy Kentucky 2021 Integrated Resource Plan*) at 42-46 [hereinafter "Duke 2021 IRP"].
[19] *Id.*
[20] *Id.*
[21] *Id.*
[22] *Id.*
[23] Hr. Video (May 9, 2023) at 3:25:18 (12:11:30 PM) (Sierra Club cross-examination of Mr. Park).

As is evident, in half of all scenarios modeled by Duke, East Bend becomes uneconomic to operate in the 2020s, no later than in 2027. But, as Duke has noted in these proceedings, all six scenarios are not equally likely. **The most likely scenario—based solely on Duke's own IRP—is the scenario with carbon regulation and the base gas price. In this scenario, East Bend is optimally retired in 2027.**

Duke's 2021 IRP is clear that the Company views carbon regulation as the most likely scenario. Duke's IRP states plainly, "Our Reference with a Carbon Regulation scenario is a description of those expectations considered most likely to unfold over the 15-year planning period with no major disruptions to the business environment."[24] Elsewhere, the IRP states, "Duke Energy Kentucky believes that a price or constraint on carbon emissions is likely to be imposed at some point in the future."[25] Duke further observes in the IRP that "it is noteworthy that changes occur within a few years after carbon regulation is put in place" and that, with respect to this outcome, "preparing for the likelihood of increased environmental regulation is a prudent course of action."[26] Duke's witness Mr. Park testified that it was "not an unreasonable conclusion" that under the Company's modeling in the IRP, the most likely scenario is one of the three scenarios with carbon regulation.[27] And, as described in greater detail below, in this proceeding, Duke has described the carbon regulation scenario in the IRP as "a proxy for other forms of regulation" and confirmed that the IRA is "one such scenario that has come to fruition."[28] The three non-carbon scenarios therefore do not reflect current reality.

Duke's view that carbon regulation is the most likely scenario (and, as described in greater detail below, subsequent developments that confirm this view) narrows the modeling to variations

[24] Ex. SC-1 (Duke 2021 IRP) at 12.
[25] *Id.* at 30.
[26] *Id.* at 54.
[27] Hr. Video (May 9, 2023) at 3:44:45 (12:31 PM) (Sierra Club cross-examination of Mr. Park).
[28] Park Reb. Test. at 12:18-23.

based solely on three gas price scenarios—base price, low, and high. Two of those scenarios—where gas is either base price or low—yield an economically optimal retirement date of 2027. Only if gas prices are high is the economic retirement date later: 2035. As with carbon, Duke does not see all possibilities as equally likely. Instead, the IRP states, "The Company's expectation is for low natural gas prices through the early 2020s, followed by price increases slightly outpacing inflation through the remainder of the planning period."[29] At the hearing, Duke Witness Park agreed that the base case scenario reflects such early low gas prices and that they are commensurate with current gas prices.[30] Mr. Park described the current state of the market as "a long way away" from the high gas price scenario modeled by Duke.[31] In other words, Duke's own modeling views the carbon scenario and base-gas price as the most likely outcome and, accordingly, yields 2027 as the economically optimal retirement date.

Thus, for the two sensitivities, (1) carbon regulation is the most likely and (2) either the base or low gas price scenarios are the most likely. The combination of those scenarios yields a retirement date of 2027. Moreover, Duke's IRP is *very* clear that the Company anticipates carbon regulation—again, describing such a scenario as the "most likely." Taking all three carbon regulation scenarios together, retirement dates range from 2027 in two scenarios to 2035 in one. 2035 is therefore the *maximum* retirement date for an economically optimal portfolio under the Company's own modeling.

In fact, Duke's 2021 IRP takes 2030, not 2035, as an anchoring date for retirements. The IRP examines "four different replacement strategies" that "were evaluated to better understand the trade-offs and impact of each strategy."[32] Those four strategies involve a range of portfolios: a portfolio that converts East Bend 2 to a gas-burning unit; one that includes a combined cycle unit;

[29] *Id.* at 18.
[30] Hr. Video (May 9, 2023) at 3:43:30 (12:30 PM) (Sierra Club cross-examination of Mr. Park).
[31] Hr. Video (May 9, 2023) at 3:45:30 (12:32 PM) (Sierra Club cross-examination of Mr. Park).
[32] SC-1 (Duke 2021 IRP) at 49-51.

one that includes more CT generation; and one that includes a significant amount of renewable resources.[33] The IRP explains, "The reason for this date is that it is in between the retirement dates of the optimized portfolios as well as the planning period."[34]

To summarize: Duke's own most recent IRP in fact identifies 2027 as the most likely year in which East Bend becomes uneconomic to operate and, for economic optimization purposes, should be retired. In light of Duke's belief that carbon regulation is more likely than not, 2035 is the *outer bound* for retirement based on the modeling, not a compromise position. That's because, in the carbon regulation scenarios, 2035 is the economic retirement date only when gas prices are high; if gas prices are within the base case or low, 2027 is the modeled economic retirement date. When accounting for the variations in retirement date among the optimized portfolios, Duke settled on 2030 as an anchoring date to use to evaluate replacement strategies.

Again, Duke's own 2021 IRP identifies these dates: 2027 as the most likely year in which East Bend becomes uneconomic to operate, and 2030 as the anchoring year for retirement and replacement. These dates are, obviously, in tension with Duke's stated retirement date of 2035. Duke first settled on the 2035 retirement date in its 2021 IRP. It provided this rationale:

> Retirement of East Bend 2 was accelerated to 2035, compared to the 2041 retirement date in the most recent rate case. This approach better positions the portfolio to respond to risk drivers identified in the scenarios that called for the retirement of East Bend 2 in the mid-2020s. This will also make the transition once East Bend 2 retires less impactful to customers by preparing for that possibility.[35]

In other words, in adopting the 2035 retirement date, Duke is "respond[ing] to risk drivers" that placed the economic retirement date for East Bend *eight to ten years earlier than 2035*. Duke anticipates the likelihood of operating East Bend at an economic loss to customers *for eight to ten years*, in

[33] *Id.*
[34] *Id.* at 49. "[T]he planning period" is, in context, a reference to the 15-year planning period for the IRP. *See, e.g.*, *id.* at 12 ("Our Reference with a Carbon Regulation scenario is a description of those expectations considered most likely to unfold over the 15-year planning period . . . .").
[35] *Id.* at 65.

choosing a 2035 retirement date. Duke's justification appears to be that a 2035 retirement—rather than an earlier date—will be "less impactful" for customers. Eight to ten years of operating an uneconomic plant, however, would in fact negatively impact customers' rates. And Duke's IRP creates four replacement strategies for 2030—cutting down the uneconomic operation of East Bend by five years.

Duke provides no clear reason in its IRP for keeping East Bend open for the additional five years between 2030 and 2035, when its own modeling predicts that East Bend will be uneconomic eight years earlier. Sierra Club Witness Shenstone-Harris noted, with respect to the IRP, "The Company has presented no evidence that keeping the plant online beyond 2030 is the lowest cost option. Based on all data provided by DEK, retiring East Bend by 2030 and replacing it w[ith] alternatives likely provides the lowest cost and lowest risk option for ratepayers."[36] As Duke Witness Park stated, "A prudent decision needs to include risk-informed economic analysis. Since the future is uncertain, a prudent decision needs to be informed by what the Company thinks is most likely to happen, based upon robust modeling and analysis."[37] The IRP demonstrates that the Company thinks East Bend is most likely to become uneconomic by the mid-2020s and that the Company will be able to replace the plant by 2030.

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In short, Duke's 2021 IRP in fact identified the mid-2020s as the most likely economic retirement date for East Bend. The *most* likely date that emerges from Duke's IRP modeling is 2027—the economically optimal retirement date for carbon regulation, which Duke views as more likely, and the base or low gas case. In the carbon regulation scenarios, 2035 is *not* most likely—rather, it is the outer bound of potential scenarios, likely economically optimal only if gas prices are

[36] Shenstone-Harris Dir. Test. at 15:17-18.
[37] Park Reb. Test. at 19:9-12.

high. After identifying the mid-2020s as the most likely retirement date, Duke then used 2030 as an anchoring date for possible retirements. Duke developed four possible portfolios that could reliably replace East Bend in 2030. Despite this suite of options, the IRP chose instead to anticipate that East Bend would lose money for customers for an additional five years beyond 2030, setting anticipated retirement only in 2035. It provided no clear explanation for this choice.

In light of the four 2030 replacement scenarios, and the absence of any meaningful analysis or factual explanation in the IRP of Duke's assertion that the 2035 portfolio would be "less impactful" for customers, the Commission should follow Duke's actual analysis, not its untethered recommendation. The Commission should follow that modeling, to ensure "fair, just and reasonable" rates for customers.[38] As early as 2021, before additional legislative, regulatory, and market dynamics pressures on the continued economic viability of East Bend, Duke's own modeling (1) found that 2027 is the most likely economically optimal retirement date for East Bend and (2) yielded a feasible retirement date no later than 2030, with four possible replacements.

2. Developments Since 2021 Confirm that No Later than 2030 Is the Most Likely Retirement Date for East Bend.

Developments since 2021 have only confirmed Duke's IRP analysis that the mid-2020s is the most likely economically optimal retirement date for East Bend, and that 2030 is a feasible date to retire the plant and reliably replace it. In fact, these developments—which overwhelmingly place pressure on the economic viability of East Bend—indicate that an even earlier retirement date might be economically optimal. Duke's testimony in this proceeding, Ms. Shenstone-Harris's analysis of Duke's modeling, the passage of the IRA, new federal environmental regulations, and Kentucky's SB 4 all indicate that the most reasonable anticipated retirement date for depreciation purposes is 2030.

[38] K.R.S. § 278.030(1).

a. Duke's Testimony in this Proceeding

First, Duke testimony in this proceeding demonstrates that Duke does *not* view 2035 as the most likely retirement date. Duke Witness Park, the managing director responsible for Duke's IRP, stated that "factors that would cause East Bend 2 to retire earlier [than 2035] have increased in likelihood" and that "[m]arket dynamics and future regulation are suggesting that the retirement of East Bend 2 is more likely to be sooner than 2035 rather than later."[39] Mr. Park acknowledged that 2027 could be the most economic retirement date for East Bend 2 "as we progress through time"[40] and that "[i]n some scenarios, East Bend 2 retires in the 2020's."[41] In fact, a Duke question to Mr. Park made clear that Duke views the likely retirement date for East Bend as before 2035: the Company asked Mr. Park, "If modeling and federal policy is suggesting that East Bend should retire earlier than 2035, why is the Company proposing to use 2035 as the anticipated retirement date?"[42]

Mr. Park's testimony further confirms that 2030 is a feasible retirement date for East Bend 2, in terms of ensuring replacement generation. Mr. Park stated:

> The Company believes that based upon current modeling and the recent legislative changes in Kentucky, retiring East Bend 2 **<u>before 2030</u>** would be challenging from an execution standpoint and as we sit today, not in the best interest of customers from a long-term cost perspective due to the remaining undepreciated book value of the East Bend 2 asset.[43]

Mr. Park's identification of 2030 as the earliest logistically feasible date for replacement of East Bend is consistent with Duke's choice of 2030 as an anchoring date in its IRP. Further, it is telling that Mr. Park identifies "**<u>2030</u>**"—*not* 2035—as the date before which retirement "would be . . . not in the best interest of customers from a long-term cost perspective." The implication, of course, is that retirement in 2030 *would* be in customers' best interest from a long-term cost perspective.

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39 Park Dir. Test. at 10:11.
40 Park Reb. Test. at 4:15.
41 Park Reb. Test. 20:4-6.
42 Park Dir. Test. 11:1-4.
43 Park Reb. Test. 7:9-13.

b. Sierra Club Witness Sarah Shenstone-Harris's Evaluation of Duke's IRP Modeling, and Ms. Shenstone-Harris's Modeling

Second, the testimony of Sierra Club Witness Shenstone-Harris confirms that East Bend "is not expected to be economic going forward, under reasonable assumptions about the future."[44] Ms. Shenstone-Harris recommends a retirement date no later than 2030 to mitigate costs and risk exposure for Duke customers.[45] Ms. Shenstone-Harris found that East Bend "incurred costs in excess of its market energy revenue and capacity value" between 2018 and 2021, and that "[t]hese excess costs have been passed on to [Duke] ratepayers."[46] This trend is expected to continue into the future: Ms. Shenstone-Harris found in her analysis that East Bend is expected to incur costs in excess of its value of between $154 million and $261 million just from 2023 to 2034.[47] Further, Ms. Shenstone-Harris found that Duke's projected fixed spending for East Bend is flawed, painting too rosy a picture for East Bend: it is "(1) substantially below industry averages, (2) unreasonably low based on historical spending, and (3) identical between scenarios with and without carbon regulation."[48] While East Bend's historical spending is equivalent to that of coal plants of similar size and age, East Bend projects fixed costs "well below the industry average," with no explanation.[49] With adjustments to these fixed cost projections to be consonant with historical and industry averages, Ms. Shenstone-Harris's analysis estimated that East Bend "will incur net losses of $261 million (on a NPV basis) over its current lifetime, or an average of $32 million per year."[50] This determination that East Bend is even less economic than Duke accounted for in its IRP indicates that Duke's modeling *overestimates* the appropriate retirement date.

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44 Shenstone-Harris Dir. Test. at 20:1-2.
45 *Id.* at 9:7-8.
46 *Id.* at 8:4-6.
47 *Id.* at 21:6-8.
48 *Id.* at 26:1-3.
49 *Id.* at 26:4-10.
50 *Id.* at 27:13-15.

Further, Ms. Shenstone-Harris determined that Duke made additional errors that skewed its modeling by failing to recognize how quickly East Bend is likely to become uneconomic. As Ms. Shenstone-Harris explained, East Bend's increasing age and widespread renewable energy adoption should increase fixed costs and, even in scenarios without carbon regulation, decrease capacity factors for East Bend.[51] Duke Witnesses Park and Luke echoed Ms. Shenstone-Harris's logic, describing their concerns about an aging plant.[52] Mr. Park likened East Bend to a car with 200,000 miles on it, explaining that while such a car may be "running great," "unknowns become more likely" with that level of wear on the vehicle.[53] He noted that East Bend itself is "already over forty years old."[54]

With respect to capacity factor, Ms. Shenstone-Harris noted that the average annual capacity factors for United States coal plants have been in the range of 53%-61% since 2012, while East Bend's average capacity factors over the past five years have been slightly lower, between 43% and 60%.[55] Duke, however, is projecting much higher capacity levels than either of these figures in scenarios without carbon regulation.[56] Ms. Shenstone-Harris explained, in logic similar to Mr. Park's, "Even if East Bend is well maintained, it is unreasonable to assume that East Bend is immune from the forced outages and breakdowns that accompany an aging generator."[57] In fact, as Ms. Shenstone-Harris noted, Duke's assumptions about East Bend's capacity factor in its modeling were inconsistent with at least four Duke witnesses' testimony in this proceeding: Ms. Lawler, Mr. Luke,

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51 *Id.* at 29:17-30:4.
52 Hr. Video (May 9, 2023) at 7:09:00 (3:55 PM) (Chairman Chandler questioning of Mr. Park); *id.* at 7:34:30 (4:21 PM) (Sierra Club cross-examination of Mr. Luke).
53 Hr. Video (May 9, 2023) at 7:09:00 (3:55 PM) (Chairman Chandler questioning of Mr. Park).
54 *Id.*
55 Shenstone-Harris Dir. Test. at 29:21-24.
56 *Id.* at 29:21-30:1.
57 *Id.* at 30:2-4.

Mr. Scott, and Mr. Swez all observed in their direct testimony that they expect East Bend's capacity factor to decline in the future.[58]

With an adjusted capacity factor, Ms. Shenstone-Harris found that East Bend is uneconomic on a going-forward basis in most likely future scenarios. Ms. Shenstone-Harris concluded, "Specifically, assuming [Duke's] forward-going spending to maintain its coal plant is in line with its historical spending, and/or there are increased carbon regulations, I find that East Bend is expected to incur costs in excess of its value between $261 million and $154 million."[59] Ms. Shenstone-Harris's modeling, and the problems with Duke's modeling that her analysis uncovers, provide substantial further evidence that an anticipated retirement date of 2030 or earlier is warranted.

c. The Passage of the Inflation Reduction Act and the Proposal and Finalization of New Federal Environmental Regulations

Third, federal legislative and regulatory developments have degraded the economic landscape for East Bend since 2021. These developments confirm that Duke's carbon regulation scenario is the appropriate model to use—with economically optimal retirement in the base and low gas cases in 2027—and that the no-carbon regulation scenario is off the table. More broadly, they point toward East Bend becoming uneconomic more quickly—possibly even more quickly than the 2021 IRP contemplates. These new developments are the recently enacted IRA and recently introduced federal environmental regulations.

The IRA, passed in 2022, provides major new tools for states and utilities to take advantage of renewable energy opportunities; as a result, it makes East Bend's continued operation less economic. As Ms. Sarah Shenstone-Harris explained in her direct testimony, the IRA "provides tax benefits for wind, solar, and battery storage, as well as other provisions that support the adoption of

[58] *Id.* at 30:13-16.
[59] *Id.* at 34:1-4.

clean energy sources."[60] Ms. Shenstone-Harris and Mr. Park agree that the anticipated impact of the IRA is to make East Bend less economic.[61] Mr. Park explained in this proceeding, "All else being equal, the Company expects that the IRA will drive more renewable additions, putting downward pressure on energy prices, which would decrease the capacity factor of coal generation."[62] He also stated, "[T]he recently passed [IRA], which, among other things, provides subsidies for low and zero-emitting generating resources, has an indirect impact on the viability of coal-fired resources."[63]

The IRA therefore means the no-carbon regulation scenario is now no longer a possible future scenario. Duke Witness Park described the carbon regulation in Duke's modeling as "a proxy for other forms of regulation that may or may not be an actual carbon tax."[64] He further explained:

> The IRA is one such scenario that has come to fruition. While the IRA doesn't directly tax a carbon-emitting resource, but by creating subsidies for zero emitting resource, it has an indirect effect on the future economics of a carbon-emitting resource.[65]

In other words, the no-carbon regulation scenario of the IRP is no longer within the world of possibility, because there *is* a proxy for carbon regulation. Even if the IRA standing alone is not the full extent of carbon regulation contemplated in the IRP's carbon regulation scenario, it is more "carbon regulation" than the no-carbon regulation scenario—because of its "indirect effect on the future economics of a carbon-emitting resource." Since the passage of the IRA, Duke has not reevaluated its anticipated retirement date of 2035 for East Bend.[66]

Significant federal environmental regulation since the IRP was developed in 2021 likewise has worsened economic prospects for East Bend, making an earlier retirement date more likely.

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60 Shenstone-Harris Dir. Test. at 14:5-8.
61 *See* Shenstone-Harris Dir. Test. at 14:8-10.
62 Hr. Video (May 9, 2023) at 4:50:30 (1:37 PM) (Sierra Club cross-examination of Mr. Park).
63 Park Reb. Test. at 2:14-3:2.
64 *Id.* at 12:18-19.
65 *Id.* at 12:20-23.
66 Hr. Video (May 9, 2023) at 4:52:00 (1:39 PM) (Sierra Club cross-examination of Mr. Park).

Duke witnesses have confirmed that the impact of these new environmental regulations is not specifically accounted for in the 2021 IRP. These new regulations include:

- Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, proposed new carbon pollution standards, a proposed rule announced by the U.S. Environmental Protection Agency (EPA) on May 11, 2023.[67] These standards, as proposed, will impact East Bend. In the proposal, EPA sets emissions limits for certain existing, modified, new, and reconstructed fossil-fuel power plants based on factors including size, how often the plant runs, and retirement dates. Under the proposed Clean Air Act 111(d) rules, existing coal-fired power plants do not face significant requirements until 2030.[68] By that date, any coal-fired power plant intending to operate past 2040 would have to install a CO_2 capture and sequestration ("CCS") system that captures 90% of its CO_2 emissions by 2030.[69] There are three subcategories for coal-fired power plants that commit to retire by 2032, 2035, or 2040: (1) if a plant commits to retire by 2032, it only must ensure there is no increase in CO_2 emission; (2) if a plant commits to retire by 2035, it must also either commit to a 20% annual capacity factor limit and ensure no increase in CO_2 emissions rate or meet an emission rate consistent with 40% gas co-firing; or (3) commit to retire by 2040 and meet an emissions rate consistent with 40% gas co-firing (share of MMBtu), a 16% reduction in gross emissions rate.[70] As Duke Witness Geers explained, "climate regulations," such as "regulation under 111(b) and 111(d) of the Clean Air Act," "are probably one of the more

[67] Ex. SC-7 at 1 (Fact Sheet, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Proposed Rule); *see also* Ex. SC-8 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; and Repeal of the Affordable Clean Energy Rule).
[68] Ex. SC-7 at 3; *see also* Ex. SC-8.
[69] Ex. SC-7 at 6; *see also* Ex. SC-8.
[70] Ex. SC-7 at 6-7; *see also* Ex. SC-8.

leading costs" for East Bend and similar power plants.[71] The Greenhouse Gas Standards and Guidelines are regulations promulgated under Section 111(d) of the Clean Air Act.[72]

- Amendment of the National Emission Standards for Hazardous Air Pollutants, commonly known as the Mercury and Air Toxics Standards (MATS), a proposed rule published by the EPA on April 24, 2023.[73] This proposed rule strengthens the standards for filterable particulate matter (fPM) and requires coal-burning plants to comply with the fPM standard.[74] Duke is analyzing the operation of its equipment, including the reliability of the relevant instrument for compliance, at the strengthened standard.[75] Mr. Geers confirmed there "could be some additional costs" and that it is possible that Duke would need to make physical changes to the unit and/or to the monitoring system that could incur additional costs.[76]

- Supplemental Effluent Limitations Guidelines and Standards (ELGs) for the Steam Electric Power Generating Point Source Category, a proposed rule published by the EPA on March 29, 2023.[77] This proposed rule revises the ELGs for steam electric plants such as East Bend.[78] Mr. Geers confirmed that East Bend will be impacted by this rule as proposed.[79]

- The "Good Neighbor Rule," a final rule publicized in pre-published form by the EPA on March 15, 2023.[80] The Good Neighbor Rule regulates smog-forming nitrogen oxide (NOx)

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71 Hr. Video (May 10, 2023) at 2:17:00 (11:52 AM) (Sierra Club cross-examination of Mr. Geers).
72 Ex. SC-7 at 1; *see also* Ex. SC-8.
73 Ex. SC-6 (National Emission Standards for Hazardous Air Pollutants; Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review).
74 *Id.*
75 Hr. Video (May 10, 2023) at 2:25:00 (12:00 PM) (Sierra Club cross-examination of Mr. Geers).
76 *Id.* at 2:26:00 (12:01 PM) (Sierra Club cross-examination of Mr. Geers).
77 Ex. SC-4 (Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category).
78 *Id.*
79 Hr. Video (May 10, 2023) at 2:11:30 (11:46 AM) (Sierra Club cross-examination of Mr. Geers).
80 Ex. SC-3 (Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards).

pollution from power plants in 23 states, including Kentucky.[81] Duke's witness confirmed that the Good Neighbor Rule "has an economic impact."[82]

- Reconsideration of the National Ambient Air Quality Standards (NAAQS) for Particulate Matter, a proposed rule published by the EPA on January 27, 2023.[83] The rule, as proposed, would reduce the level of primary annual fine particulate matter (PM 2.5) from 12 micrograms per cubic meter to the range of 9-10 micrograms per cubic meter.[84] Mr. Geers confirmed that this reconsideration of the NAAQS, as proposed, "could translate into additional costs" for East Bend via efforts to ensure Kentucky's compliance.[85]

Environmental regulations, too, therefore indicate a retirement date earlier than 2035 is most likely for East Bend. The IRP, which places the date at which East Bend is most likely uneconomic going forward as in the mid-2020s, does not specifically account for any of these regulations. Duke has presented two conflicting positions as to whether the IRP modeling accounts in any way for these kinds of environmental regulations. On the one hand, the IRP states:

> Future regulation cannot be forecast in a quantitative manner, and therefore the current regulatory environment is assumed to persist throughout the planning period. The one major exception to that assumption is in regard to a future price on carbon emissions which, given its potential impact, is addressed in a number of other scenarios.[86]

If this is the case, according to Duke's IRP itself, the IRP did not even account for other environmental regulations. These regulations, as Duke's witnesses testified, make generation units like East Bend less economic rather than more economic and have the potential to ultimately affect

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81 *Id.* at 11-12.
82 Hr. Video (May 10, 2023) at 2:06:00 (11:40 AM) (Sierra Club cross-examination of Mr. Geers).
83 Ex. SC-5 ("Reconsideration of the National Ambient Air Quality Standards for Particulate Matter").
84 *Id.*
85 Hr. Video (May 10, 2023) at 2:17:00 (11:52 AM) (Sierra Club cross-examination of Mr. Geers). Mr. Geers described the process by which reconsideration of the NAAQS could lead to direct regulation of East Bend. *Id.*
86 Ex. SC-1 (Duke 2021 IRP) at 12.

East Bend's retirement date.[87]As Duke Witness Park observed, "Federal policy is likely going to continue to negatively impact the service life of East Bend."[88] Thus, if the IRP's modeling includes carbon regulation but not the other environmental regulations, then it is likely that East Bend will become uneconomic *before* the dates specified in the IRP's carbon regulation scenario—before 2027, for the base and low gas rates, and before 2035, for the high gas rate.

On the other hand, witnesses at the hearing testified that one "could argue" that the Good Neighbor Rule and other environmental regulations are within the carbon regulation scenario.[89] This interpretation comes, of course, years after the IRP and is in tension with the IRP's categorical rejection of forecasting beyond carbon regulation. Even if one generously credits this interpretation then the plethora of environmental regulations must mean that Duke is squarely within the carbon regulation scenario. This is along with, as well, the IRA's passage—which, as described above, Duke has described as a carbon regulation "scenario that has come to fruition." And, again, carbon regulation means that under base or low gas rates, 2027 is the economically optimal date for East Bend's retirement.

In any event, environmental regulation—including carbon regulation under Section 111(d) of the Clean Air Act—and the IRA squarely eliminate Duke's "no carbon regulation" scenario from the universe of future possibility. The carbon regulation scenario that Duke modeled in the 2021 IRP is the only scenario that remains.

[87] Hr. Video (May 9, 2023) at 5:17:00 (2:04 PM) (Sierra Club cross-examination of Mr. Park); Hr. Video (May 10, 2023) at 2:23:00 (11:57 AM) (Sierra Club cross-examination of Mr. Geers) (explaining that additional costs are "modeled into the viability of the unit on a long-term basis").
[88] Park Reb. Test. at 2:14-15.
[89] Hr. Video (May 9, 2023) at 4:45:30 (1:32 PM) (Sierra Club cross-examination of Mr. Park).

C. Kentucky's New Senate Bill 4 Favors Aligning Depreciation with Anticipated Retirement with Care and Preserving Flexibility by Targeting Earlier Rather than Later Retirement Dates.

On March 29, 2023, Kentucky Senate Bill 4, an Act Relating to the Retirement of Fossil Fuel-Fired Electric Generating Units (SB 4), became law.[90] SB 4 provides this Commission with "the authority to approve or deny the retirement of an electric generating unit owned by a utility."[91] SB 4 further establishes a procedure for utilities to seek Commission approval of retirements. The law requires the Commission to make certain findings in order to "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."[92] To authorize a retirement or take other action allowing for cost recovery for retirement, among other findings the Commission must determine that "[t]he 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" and that "cost savings will result to customers as a result of the retirement of the electric generating unit."[93]

SB 4 is not directly at issue in this litigation. Duke has not applied to the Commission for an order approving the retirement of East Bend.[94] Nor is Duke requesting that the Commission take an "action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery."[95] Nevertheless, the shadow of SB 4 looms

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90 Ky. General Assembly, *Senate Bill 4*, https://apps.legislature.ky.gov/record/23rs/sb4.html; Ky. Acts Ch. 118, Senate Bill 4, An Act Relating to the Retirement of Fossil Fuel-Fired Electric Generating Units and Declaring an Emergency [hereinafter "SB 4"], § 3 (SB 4 to take effect immediately).
91 SB 4, § 2(1).
92 SB 4, § 2(2).
93 SB 4, §§ 2(2)(b), 2(3).
94 *See* SB 4, § 2(1).
95 *See* SB 4, § 2(2).

over the question of East Bend's anticipated retirement date. Because SB 4 makes it difficult to retire an uneconomic asset that will become a stranded asset, and disincentivizes a utility from doing so, SB 4 heightens the importance of aligning depreciation with the most probable retirement date. The prohibition on stranded asset recovery without a showing from the utility that "[t]he 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" may make it difficult for a utility to retire a plant that is not fully depreciated.

Duke Witness Lawler stated that a lack of alignment between depreciation and an anticipated retirement date would ensure that "the utility's customers ***will be*** exposed to net incremental costs."[96] Ms. Lawler explained that waiting for a later proceeding to address the retirement date for East Bend is economically risky for customers: if alignment of depreciation is not addressed in this proceeding, in future "it may be too late for the Commission to take meaningful action to mitigate costs for customers regarding the remaining undepreciated NBV [net book value] of the unit."[97] The issue worsens over time:

> If the Commission only approves depreciation rates to align with a 2041 retirement date, the remaining NBV of the East Bend generation asset will be approximately $134 million at the end of 2035, before adding any new needed capital for maintenance between now and then. This balance will be borne by future customers and will serve as an impediment to the prudent retirement of the asset. The issue compounds itself as the generating asset will require further investment once the prudent retirement date passes, further prolonging the issue at the customer's expense.[98]

In other words, under SB 4, failure to align depreciation and anticipated retirement jeopardizes Duke's ability to retire East Bend at the appropriate date. As described above, that date is no later than 2030. The bar against "incur[ring] net incremental costs to be recovered from ratepayers" in SB

[96] Lawler Reb. Test. at 7:17-19.
[97] Lawler Reb. Test. at 11:19-21.
[98] Lawler Reb. Test. at 13:9-16.

4 requires careful planning in order to ensure that a utility can, and has the appropriate incentives to, seek retirement when a unit becomes uneconomic. This careful planning is not new to the Commission, of course—as described above, the Commission regularly ensures alignment between depreciation and the anticipated useful life of a generating unit. As a result, SB 4 is another factor that weighs in favor of the Commission anticipating an earlier retirement date rather than a later one.

D. Failure to Preserve Flexibility to Retire East Bend by 2030 Carries Reliability Risks, as East Bend Will Likely Become Less Reliable.

Finally, failure to align depreciation with the most likely retirement date for East Bend of 2030 risks increased reliance on a unit likely to become increasingly unreliable. As Duke has explained, East Bend was "made for base load operation."[99] As East Bend becomes less economic, it will run less in the PJM system.[100] But, East Bend is not made to start and stop in this manner. As Duke's witness Mr. William Luke explained, "What that can lead to over time is equipment starts to fail at a higher rate. So that leads to higher forced outage factors—in particular, you know, these large, old coal units, the boilers, we tend to have boiler leaks. So then when you need the unit the most, you go to start it up, and you may be dealing with a boiler leak."[101] The forced outages that are more common with older and cycling units decrease life expectancy and can render units functionally inoperable for a period of time.[102] As Mr. Luke explained:

> When a unit like that operates infrequently, is it going to be there when you need it most—right? . . . So that's what you risk, is, when you need it most, you go to start that asset up, and it's not available. And then, if the power's there, if the resources are there on the market, that's great, but if they're not—then that can further impact the customers, and maybe replacement power's extremely high at that time.[103]

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[99] Hr. Video (May 9, 2023) at 7:33:30 (4:20 PM) (Sierra Club cross-examination of Mr. Luke).
[100] Swez Dir. Test. at 10:3-19.
[101] Hr. Video (May 9, 2023) at 7:34:00 (4:20 PM) (Sierra Club cross-examination of Mr. Geers).
[102] Hr. Video (May 9, 2023) at 7:37:00 (4:23 PM) (Sierra Club cross-examination of Mr. Geers).
[103] Hr. Video (May 9, 2023) at 7:39:00 (4:25 PM) (Sierra Club cross-examination of Mr. Geers).

Aligning depreciation date with anticipated retirement not only furthers customers' economic interests but also ensures reliability. This alignment makes it feasible for companies like Duke to easily remove uneconomic plants that are in a vicious spiral, as they experience cycling operation, develop equipment or maintenance problems, and become less economic. It also allows Duke to replace such a cycling, unreliable plant with a minimum amount of destabilization for customers.

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As Duke noted in its IRP, "preserving the option to react is paramount"[104] given the swiftly changing regulatory landscape and the implications of that regulation for customers. Having a large amount of undepreciated value still on the books makes it especially difficult for a utility to react nimbly with the passage of SB 4. Substantial evidence points toward 2030 as the most likely retirement date: Duke's own IRP modeling that indicates that 2027 is the economically optimal retirement date in both base and low gas rate cases; Duke's testimony that 2030 is the earliest feasible retirement date after the plant becomes uneconomic to operate; Ms. Shenstone-Harris's modeling that shows Duke's IRP makes overly rosy assumptions about East Bend's capacity factor and projected operating costs; the passage of the IRA; and new proposed federal regulation that includes significant regulation of greenhouse gas emissions for plants such as East Bend.

Ensuring that Duke has the flexibility to retire East Bend by 2030 is in the best interest of Duke's customers, given the significant evidence that East Bend is uneconomic for customers, is not likely to be operating at a high capacity factor, and will likely become less reliable. In light of the principle of aligning depreciation with retirement that this Commission adheres to, and especially the potential significant difficulty in retiring an undepreciated unit under SB4, the Commission should align the depreciation rate for East Bend with an anticipated retirement date of 2030.

[104] Ex. SC-1 (Duke 2021 IRP) at 43.

II. The Commission Should Require Duke KY, as Part of its Next IRP, to Analyze How the New Statutes and Regulations Impact the Economics of East Bend.

The Commission should order the Company, as part of its next IRP, to evaluate the economics of East Bend, including evaluating alternative replacement portfolios that meet reliability standards, in light of the slate of new final and proposed laws and regulations changes in market dynamics. If an earlier date is found to be the least-cost, the Commission should require Duke to file another rate case to adjust its depreciation schedule. This would minimize rate shock to customers while still allowing Duke to recover the capital the Company invested in the plant.

A. The Legal and Regulatory Landscape and Market Dynamics Have Significantly Changed Since 2021.

Since Duke completed its IRP in 2021, the economic and legal and regulatory landscape have changed significantly. Congress passed the IRA, EPA finalized and proposed new regulations, and world events impacted costs and availability of products. The Company has not yet performed any detailed analysis of the impact of any of these forces on its long-term resource plan, despite acknowledging that some of these changes likely shorten the economic life of East Bend.

The IRA is, to date, the most significant climate legislation in United States history. The IRA provides a full suite of tools to move the country towards clean electricity. First, it provides critical clean energy technology tax credits. The Investment Tax Credit sets a baseline tax credit at 30% of total capital costs for renewable generation and battery storage, with an additional 10% for location in an "energy community" and another 10% adder for reliance on domestic manufacturing.[105] The Production Tax Credit provides $27.50 per MWh (currently) for electricity generated by clean energy, with the additional 10% adders (for a total of 20%) for location in an "energy community"

[105] Shenstone-Harris Dir. Test. at 37:3-16; *see also* Inflation Reduction Act, Pub. L. No. 117-169 (Aug. 16, 2022), *available at* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

and reliance on domestic manufacturing.[106] The IRA also has provisions that allow utilities access to low-cost financing, including a program that creates a $5 billion fund for the U.S. Department of Energy's Loan Programs Office to facilitate low-cost loans up to $250 billion in principal, called the Energy Infrastructure Reinvestment Program.[107] The government backing provides security needed for utilities to access financing at the lowest possible interest rates, the role previously played by ratepayer-backed securitization. Utilities can use this financing to replace energy infrastructure or reduce emissions from energy infrastructure that will remain operational. By coupling tax credits with financial support to pay down uneconomic fossil plants, the IRA opens the door to new cheap and clean generation resources, while incentivizing that these investments are made in the energy-dependent and rural communities that need it most.

Utilities should not delay analyzing and benefiting from the IRA, as its provisions are time bound. First, the Department of Energy must disperse money under the Energy Infrastructure Reinvestment Program by 2026.[108] Second, the tax credits will phase out in the later of 2032 or when the Treasury Secretary determines that there has been a 75% or more reduction in annual greenhouse gas emissions from electricity production in the United States, relative to 2022.[109] So, the time for utilities to act is now.

While the IRA will help make renewable energy more competitive, finalized and proposed environmental pollution standards for existing coal-fired power plants will likely worsen the financial outlook for such plants. Most notably, EPA's proposed new carbon dioxide ("CO2') standards for

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[106] Shenstone-Harris Dir. Test. at 37:3-16; *see also* Inflation Reduction Act, Pub. L. No. 117-169, § 13701 (Aug. 16, 2022), *available at:* https://www.congress.gov/bill/117th-congress/house-bill/5376/text.
[107] Shenstone-Harris Dir. Test. at 37:3-16; *see also* Inflation Reduction Act, Pub. L. No. 117-169, § 50144(c) (Aug. 16, 2022).
[108] Shenstone-Harris Dir. Test. at 37:3-16; *see also* Inflation Reduction Act, Pub. L. No. 117-169 (Aug. 16, 2022).
[109] Shenstone-Harris Dir. Test. at 37:3-16; *see also* Inflation Reduction Act, Pub. L. No. 117-169 (Aug. 16, 2022).

power plants under the Clean Air Act are likely to negatively impact East Bend's economic outlooks.[110] In the proposal, as described above, EPA sets emissions limits for certain existing, modified, new, and reconstructed fossil-fuel power plants based on factors including size, how often the plant runs, and retirement dates. And, as described above, existing coal-fired power plants will by 2030 face significant requirements: installation of a CO2 capture and sequestration system by 2030 or retirement commitments by 2032, 2035, or no later than 2030, with increasingly stringent requirements accompanying the later retirement commitment dates.[111]

In addition to the proposed 111(d) rule, as discussed above, a range of other regulations will likely impact East Bend including the Good Neighbor Rule,[112] the MATS Rule,[113] the ELG Rule,[114] and the NAAQS for particulate matter.[115]

Finally, in addition to laws and regulations that directly address climate change and pollution from coal-fired power plants, external world forces have changed market dynamics. As a result of global energy market changes that stemmed from the war in Ukraine, there has been more gas price volatility and higher regional coal prices.[116] This has not only impacted the fuel costs for fossil fuel plants; it has also driven up energy prices across the region.[117] This type of fuel volatility is inherent to systems that rely heavily on gas and coal plants. In addition, the country has experienced inflation

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110 Ex. SC-7 at 1 (Fact Sheet, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Proposed Rule); *see also* Ex. SC-8 (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; and Repeal of the Affordable Clean Energy Rule).

111 Ex. SC-7 at 3, 6-7; *see also* Ex. SC-8.

112 Ex. SC-3 (U.S. Environmental Protection Agency, Final Good Neighbor Rule (March 15, 2023)).

113 Ex. SC-6 (U.S. Environmental Protection Agency's Proposed Mercury Air Toxics Rule (April 3, 2023)).

114 Ex. SC-4 (Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, published in the Federal Register by the U.S. Environmental Protection Agency (March 29, 2023)).

115 Ex. SC-5 (U.S. Environmental Protection Agency's Proposed Reconsideration of the NAAQS for particulate matter proposed (January 27, 2023)).

116 Shenstone-Harris Dir. Test. at 14:13-17.

117 *Id.*

and supply chain challenges.[118] "This has driven up prices across numerous industries, including the energy industry. This both impacts the cost of new resources and increases the cost to operate and maintain existing resources like East Bend, especially if additional environmental capital costs are required."[119] Moreover, coal has been greatly impacted by inflation, with rising costs related to mining.[120]

B. The Commission Should Require Duke to Analyze how Post-2021 Changes Have Impacted the Economic Useful Life of East Bend, and Require Duke to File Another Rate Case to Adjust its Depreciation Schedule If an Earlier Date is Found to Be the Least-Cost.

Duke has not performed any detailed analysis of how the IRA, proposed and final environmental regulations, and new market dynamics influences its generation portfolio, including the economic useful life of East Bend. Duke's current modeling, as described above, places the most likely economically optimal retirement date in 2027, and Duke's current analysis shows 2030 as the earliest feasible retirement date. But Duke has not reevaluated its set retirement date for East Bend since the IRA became law in August 2022, and it has not conducted a detailed analysis of the IRA's impacts.[121] Since Duke's stale analysis does not accurately depict the current state of affairs, the Commission should order Duke, as part of its next IRP, to evaluate the economics of East Bend in light of the slate of new final and proposed statutes and regulations and changes in market dynamics. This analysis should include evaluating alternative replacement portfolios in light of reliability standards, ensuring that portfolios meet these standards. Moreover, given how important it is to align the depreciation life of a plant with its expected retirement date, the Commission should require Duke to file another rate case to adjust its depreciation schedule if an earlier date is found to be the least-cost.

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118 Shenstone-Harris Dir. Test. at 14:18-22.
119 *Id.*
120 Hr. Video (May 10, 2023) at 33:30 (Sierra Club cross-examination of Witness Swez).
121 Hr. Video (May 9, 2023) (Sierra Club cross-examination of Mr. Park).

The Company has not performed any detailed analysis of the IRA impacts, as it relates to its Integrated Resource Planning beyond high level considerations of tax incentive and updating of fuel prices.[122] Duke acknowledged that the IRA would impact coal generation, such as East Bend. "All else being equal, the Company expects that the IRA will drive more renewable additions putting downward pressure on energy prices which would decrease the capacity factor of coal generation."[123] Duke Witness Park stated that "[f]ederal policy is likely going to continue to negatively impact the service life of East Bend. For example, the recently passed Inflation Reduction Act (IRA) initiative, which, among other things, provides subsidies for low and zero-emitting generating resources, has an indirect impact on the viability of coal-fired resources."[124]

EPA's 111(d) rule was proposed during the hearing in this case, so Duke obviously hadn't analyzed how it would likely impact East Bend or other generation assets.[125] Nonetheless, as discussed above, Duke acknowledged that when carbon regulations came to pass their impact would be swift and that preparing for that moment is paramount. Duke's 2021 IRP states that "should carbon regulation come to fruition of a similar magnitude to what is assumed in this IRP, economic retirement of East Bend follows within a few years."[126] The IRP goes on to state that "[g]iven the swiftness with which carbon regulation can impact the Duke Energy KY portfolio in a significant way, preserving the option to react is paramount."[127] Duke's 2021 IRP stressed the importance of preparedness: "In many cases, the timing of these changes is less than the time it takes to go through

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122 Duke's Response to Sierra Club DR 1-23.
123 Duke's Response to Sierra Club DR 1-23.
124 Park Reb. Test. at 2:14-3:2.
125 Hr. Video (May 11, 2023) at 5:21:47, 5:22:36, 5:25:44-5:25:54 (Sierra Club cross examination of Ms. Lawler).
126 Ex. SC-1 (Duke 2021 IRP) at 42-43.
127 Ex. SC-1 (Duke 2021 IRP) at 43.

the permitting process, procure resources and construct the facility. Because of this, preparing for the likelihood of increased environmental regulation is a prudent course of action."[128]

While Duke's 2021 IRP assumed carbon regulation in its base case, it did not include any other costs to comply with future environmental regulations.[129] Duke did not conduct any sensitivity analyses of the impact such regulations might have on the economics of its proposed plan.[130] While Duke acknowledged the risk that the future environmental regulations could create additional compliance issues, it completely ignored the risk of those costs in its economic analysis. Duke did say that the carbon regulation in its base case, could act "as a proxy for other forms of regulation that may or may not be an actual carbon tax."[131] But Duke also believes that the carbon tax serves as a proxy for the IRA: "The IRA is one such scenario that has come to fruition. While the IRA doesn't directly tax a carbon-emitting resource, but by creating subsidies for zero emitting resource, it has an indirect effect on the future economics of a carbon-emitting resource."[132] Since Duke finished the modeling for the 2021 IRP, the IRA has become law, and EPA has finalized the Good Neighbor Rule and proposed the 111(d) carbon regulation, ELG update, MATS update, and new NAAQS for particulate matter. It is highly unlikely that the carbon tax included in the base case could serve as a proxy for all of these different regulations, especially in light of the fact that one of the new proposed regulations is actual carbon regulation. While Duke has provided conflicting statements on the scope of the carbon regulation and its ability to substitute for all environmental regulation, the fact that there is conflict—and the fact that Duke's 2021 IRP itself states that it does not account for any environmental regulations beyond carbon—means that updated modeling that takes into account the likely impact of these new regulations is essential.

128 Ex. SC-1 (Duke 2021 IRP) at 54.
129 Hr. Video (May 9, 2023) at 4:42:00-4:49:03 (Sierra Club cross examination of Mr. Park).
130 Hr. Video (May 9, 2023) at 4:42:00-4:49:03 (Sierra Club cross examination of Mr. Park).
131 Park Reb. Test. at 12:12:20-23
132 Park Reb. Test. at 2:17-19.

Similarly, Duke has not updated its modeling to incorporate shifts in market dynamics such as fuel volatility, changes in energy market prices, and supply chain issues.[133] Duke acknowledged that changing market dynamics seen within the last two years will have a material impact on East Bend's economics. In fact, Company Witness Park states in his direct testimony that, in light of market changes, "the retirement of East Bend is more likely to be sooner than 2035 rather than later."[134]

In light of all of these significant changes that Duke acknowledged could impact the economic useful life of East Bend,[135] the Commission should order Duke in its next IRP to evaluate how the IRA; the proposed 111(d) rule; the finalized Good Neighbor Rule; the proposed ELG update; the proposed MATS update; the proposed NAAQS for particulate matter, and changes in market dynamics have influenced its preferred generation portfolio and timeline. If this next IRP finds that an earlier retirement for East Bend than 2030 is the least-cost option, the Commission should order Duke to file another rate case to align its depreciation schedule with this newly identified date so that customers don't have to incur capital investment costs for a generating unit is no longer economical.[136] Duke Witness Lawler stressed the importance of not waiting to align deprecation with the expected economic useful life of a plant because by "that time, it may be too late for the Commission to take meaningful action to mitigate costs to customers regarding the remaining undepreciated net book value of the unit."[137]

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[133] Shenstone-Harris Dir. Test. at 15:9-15

[134] Shenstone-Harris Dir. Test. at 15:9-15.

[135] Hr. Video (May 9, 2023) at 4:54:36 (Sierra Club cross examination of Mr. Park).

[136] Lawler Reb. Test. at 12:4-14.

[137] Lawler Reb. Test. at 12:4-14.

C. The Commission Should Require Duke, in Its Next IRP, to Analyze how to Reliably Replace Generation Expected to Retire, Including Any Necessary Modeling.

Ultimately, the Commission should encourage Duke to start planning for and building the replacement generation for East Bend sooner rather than later. Such steps are necessary to fully capture the benefits of the IRA for Duke's customers, to ensure that supply chain issues don't snarl construction and operation timelines, and most notably to ensure that Duke can reliably serve its customers' needs. The first step in that process is actually determining when the economic useful life will end for assets nearing that stage (which was discussed above). The second step is robustly analyzing all replacement portfolio options, including modeling the reliability of each replacement portfolio. Although Duke is a member of PJM, Chairman Chandler repeatedly noted that Kentucky has never ceded its authority or obligations to ensure Kentucky has a reliable energy and capacity to serve its residents.[138] To ensure that the Kentucky Public Service Commission can meet that obligation, the Commission should order Duke in its next IRP to analyze a full suite of replacement portfolio options, including modeling the reliability of each portfolio based on information about how various resources would perform under severe winter weather and reasonably expected outage rates.

The Commission should require that the reliability modeling account for extreme weather events. Unfortunately, extreme weather events appear to be happening at a greater clip than historical events—such as the Polar Vortex, Winter Storm Elliot, and Winter Storm Uri. All generation resources experience the impacts of these extreme weather events and it is important that all reliability modeling accurately reflects this reality. Extreme weather impacts coal generators,

[138] Hr. Video (May 9, 2023) at 6:04:55 to 6:05:26 (Chairman Chandler questioning of Mr. Park).

including Kentucky generators.[139] For instance, during Storm Elliot all of TVA's coal plants in Kentucky had loss of availability.[140]

In addition, the reliability modeling should accurately reflect reasonably expected forced outage rates. As East Bend continues to age, more forced outages are likely. As generators age, the likelihood and frequency of forced outages increases.[141] For instance, CenterPoint's Culley Unit 3 in Indiana was shut down unexpectedly for nearly six months due to a turbine failure. Not only did this put reliability at risk, but it has also led to a rate hike for CenterPoint customers to cover the cost of replacement energy.[142] Further, as discussed above, more forced outages are likely for East Bend as the plant becomes more uneconomic and is more frequently offline.

More forced outages also impact capacity value.[143] A higher forced outage rate results in a lower Unforced Capacity.[144] This means that, over time, East Bend will provide less and less capacity for the Company to use to satisfy its FRR Plan or to monetize in the PJM capacity auctions and through bilateral sales.[145] Since East Bend accounts for approximately half of Duke's capacity, it is reasonable and prudent to start to analyze and build out capacity and energy resources now (when Duke can still take advantage of the IRA), ahead of prolonged forced outages and/or noticeable deteriorations in East Bend's unforced capacity.

D. The Proper Method to Handle Uncertainty Surrounding Future Environmental Regulations is to Analyze the Risk.

While Duke's 2021 IRP considered possible future carbon regulation in its base case, Duke stated that if it came in for a CPCN, it would only consider compliance costs associated with final

139 Shenstone-Harris Dir. Test. at 44:7-8.
140 Shenstone-Harris Dir. Test. at 44:7-8.
141 Shenstone-Harris Dir. Test. at 44:11-45:4.
142 *Id.*
143 Shenstone-Harris Dir. Test. at 45:5-12.
144 *Id.*
145 *Id.*

environmental regulations.[146] When Duke Witness Spiller was pressed on the fact that such a piecemeal approach could deprive the Commission of necessary risk information, Witness Spiller confirmed that Duke would only consider compliance costs associated with final rules.[147] This is not the prudent way to handle risk. There is uncertainty surrounding future environmental regulation, including timing and the stringency of final requirements. But uncertainty associated with environmental compliance costs is not unique. The appropriate way for a utility to handle uncertainty is to stress-test whether its proposal performs well under various uncertainties, and will thus minimize harm to customers if those risks come to fruition.

Simply put: the question is not whether, but how, to prudently manage such uncertainty. Ignoring a major potential cost, such as potential carbon or other environmental regulations, is not an appropriate or prudent approach to accounting for uncertainty. By ignoring possible costs associated with foreseeable environmental regulations, Duke could bias its economic analysis towards portfolios with coal-fired power plants, unnecessarily exposing its customers to risk. Such a practice could lead the Company to improperly pursue a piecemeal approach that ultimately harms customers by requesting cost recovery for a single upcoming cost in a CPCN rather than considering the full possible costs to customers of continuing to operate the plant. Without factoring in the full range of known and likely costs that customers would have to bear, it is not possible to develop a least-cost portfolio, or assure that the costs associated with a certain portfolio will not be stranded before the plant is fully depreciated.

Prudent utility planning regularly involves evaluating numerous uncertainties and variables, including fuel prices and energy and capacity prices. Even though the price of coal or gas ten years from now is uncertain, prudent utility practice dictates looking at various sensitives to understand

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146 Hr. Video (May 11, 2023) at 6:16:19 (Sierra Club cross examination of Ms. Spiller).
147 Hr. Video (May 11, 2023) at 6:21:58 (Sierra Club cross examination of Ms. Spiller).

and quantify the uncertainty, rather than ignoring risk altogether. In utility planning, there are two proper methods, which are not mutually exclusive, for reasonably handling uncertainty associated with environmental risk. First, a utility could use a range of potential future environmental compliance scenarios to bound the risk. Second, the utility could probability weight the outcomes.

The practice of utilities and commissions across the country have almost uniformly considered and rigorously evaluated the risks and cost impacts of foreseeable and impending environmental compliance obligations when making prudence determinations. In fact, as early as 2014, this Commission noted the need for such consideration. In *In re: East Kentucky Power Cooperative for a CPCN for Alteration of Certain Equipment at Cooper Stat.*, Case No. 2013-00259, Order (Feb. 20, 2014) the Commission stated:

> While the Commission recognizes that the capital expenditure in this case (approximately $15 million) is relatively small for an Environmental Compliance Plan, with other projects for this utility and other utilities costing in the hundreds of millions of dollars, we are nonetheless concerned with the lack of sensitivity analysis performed in this case with regard to future environmental rules and regulations, including, but not limited to, the cost of complying with Section 111(d) of the Clean Air Act. While the costs of running additional analyses may have exceeded the benefit of more accurate information in this case, it is troubling that EKPC, through a company witness, indicated that it does not model anticipated future environmental rules and regulations. Modeling future uncertainty is difficult, but doing so can shed important light on decisions such as these. Accordingly, notwithstanding our finding that EKPC was reasonable in not considering potential environmental compliance costs in its analysis given the specific facts of this case, in the future we expect that these types of sensitivity analyses will be conducted as part of a utility's prudent evaluation of alternatives to any environmental compliance plan.[148]

Other commissions across the country have also addressed this issue; for instance, the Indiana Utility Regulatory Commission, citing the risk of carbon regulation to the economic viability of a

[148] *In re: East Kentucky Power Cooperative for a CPCN for Alteration of Certain Equipment at Cooper Stat.*, Case No. 2013-00259, Order at p. 19 (Feb. 20, 2014); see also In the Matter of: Elec. 2018 Joint Integrated Res. Plan of Louisville Gas & Elec. Co. & Kentucky Utilities Co., No. 2018-00348, 2020 WL 4209263, at *11 (July 20, 2020) ("The potential impact of existing and future environmental regulations affecting the price of electricity and other economic variables continues to be a topic of significant interest. Therefore, the effects of such regulations should continue to be examined by LG&E/KU as a part of their load forecasts and sensitivity analyses in the next IRP filing.").

coal unit, determined that a utility that assumed a zero-carbon cost in its base case would have to assume responsibility for future carbon regulation should carbon regulation render the unit non-economic.[149]

Given the substantial cost risk associated with potential environmental regulations, the Commission should advise Duke that in order to comply with Kentucky's prudency standard for a CPCN and other proceedings before the Commission, it must consider the risk of other environmental regulations in selecting the least-cost resource option and evaluating alternatives. This is the only reasonable way to handle this risk; otherwise, the Commission would experience a series of piecemealed applications that never quantify the entire risk to customers over the full analysis period.

III. The Commission Should Modify the Electric Vehicle Related Tariffs so that They Truly Incentivize Customers to Change Their Behavior and Charge Off-Peak.

The incremental load from electric vehicles ("EVs") will create a broader base of sales over which to spread utility costs.[150] This can lead to "savings to all customers" due to "incremental net revenue received by selling electricity to charge EVs in excess of any increases in costs of service related to the additional load."[151] However, growth in energy usage "must be actively managed to assure the greatest benefits for all customers," primarily through "smooth[ing] charging load to reduce the need for infrastructure growth at all levels."[152] So, rates should encourage EV customers to charge in a manner that minimizes additional grid investments, as this benefits all customers.

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149 Indiana Utility Regulatory Commission. August 14, 2013. Verified Petition of IPL for Approval of Clean Energy Projects, Cause 44242, Final Order, page 36. Available at https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/e9ce3837-3c83-e611-810e-1458d04f0178/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44242order_081413.pdf.

150 Gordon Dir. Test. at 4:7-9, Hr. Video (May 10, 2023) at 9:11:35; *see also* Shenstone-Harris Dir. Test. at 54:18-19.

151 Gordon Dir. Test. at 4:9-12, Hr. Video (May 10, 2023) at 9:12:18; *see also* Shenstone-Harris Dir. Test. at 54:23-55:3.

152 Gordon Dir. Test. at 6:1-5; *see also* Shenstone-Harris Dir. Test. at 54:23-55:3.

Unfortunately, Duke's three proposed EV-related tariffs are unlikely to incentivize widespread enrollments in the rates, and thus unlikely to shift EV load to off-peak hours.[153] In fact, several modifications to the Company's commercial rates would actually increase the cost of EV adoption through increasing demand charges, while reducing incentives for customers to charge during off-peak hours.[154] This could unduly stress the system. The Commission should modify these tariffs to incentivize customers to smooth the load by charging during off-peak hours.

A. Duke's Residential EV Tariff Included in Rate RS-TOU-CPP Provides Too Small a Benefit to Actually Incentivize Customers to Enroll in the Rate and Shift Usage.

The Company's proposed RS-TOU-CPP rate offers a very modest price discount relative to the standard residential rate. Specifically, customers charging during the off-peak period would save less than a penny per kilowatt-hour, while customer charging during the discount period would save less than $0.03/kWh.[155] These rate differentials do not provide substantial savings to a typical residential EV customer using 300 kWh per month for EV charging.[156] If an EV customer were to charge 100 percent during the off-peak hours, they would only save $2.40 per month.[157] If that customer were able to charge 100 percent during the discount hours, they would only save $8.37 per month.[158]

A rate must provide meaningful financial incentives in order for customers to take the time and effort to enroll in the rate and shift their usage on a regular basis.[159] This is particularly true for rates for the entire home as customers bear the risk that the rest of their households' usage patterns could result in higher bills under the new rate.

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153 Shenstone-Harris Dir. Test. at 55:18-56:5.
154 *Id.*
155 Shenstone-Harris Dir. Test. at 55:8-12.
156 Shenstone-Harris Dir. Test. at 55:13-14.
157 Shenstone-Harris Dir. Test. at 55:14-16.
158 Shenstone-Harris Dir. Test. at 55:16-17.
159 Shenstone-Harris Dir. Test. at 56:3-7.

Unfortunately, the difference between $2.40 and $8.37 per month is insufficient to motivate many customers to enroll in the RS-TOU-CPP rate.[160] Sierra Club Witness Shenstone-Harris reviewed EV tariffs and enrollment levels in other jurisdictions and observed that unless an EV rate offered the prospect of substantial savings the rates suffered from low enrollment:

- Duquesne Light Company in Pennsylvania offered an EV time-of-use rate since June 2021. This rate provides approximately $9 in monthly savings for an EV customer who can charge during the super-off-peak period. Although Duquesne Light Company has proactively marketed the rate to customers, only 7 percent of EV drivers in its territory have enrolled in the rate.[161]
- In Maryland, Baltimore Gas & Electric's EV time-of-use rate offers approximately $10.50 in monthly savings for EV charging, but the utility successfully enrolled less than 5 percent of its EV customers on the rate between May 1, 2020 and June 30, 18 2022.[162]

The Commission should strengthen the on-peak to off-peak differential to provide greater incentives for customers to enroll in the rate. This will benefit all customers as it will to reduce the need for infrastructure growth at all levels.

B. The Commission Should Modify Duke's DT Rate So That It is a Time-Varying Volumetric Charge Instead of a Non-Coincident Peak Rate.

Rate DT is applicable to customers with an average monthly demand of 500 kW or greater.[163] Customers on this rate may include EV DC Fast-Charging customers or larger fleet customers, such as those with heavy-duty trucks. The Company proposes to change its Time-of-Day

160 Shenstone-Harris Dir. Test. at 57:1-19.
161 Shenstone-Harris Dir. Test. at 57:11-15.
162 Shenstone-Harris Dir. Test. at 57:15-19.
163 Shenstone-Harris Dir. Test. at 59:8-11.

Distribution Voltage Rate DT such that a $6.23/kW non-coincident demand charge would be added to recover distribution demand costs.[164] These costs would be removed from the other rate components. When combined with the tariff's existing demand charges, the proposal would result in a demand charge of the $20.61/kW during winter on-peak hours, $21.43/kW during summer on-1 peak hours, and $7.60/kW during all off-peak hours.[165]

There are two primary problems with Rate DT. First, the non-coincident demand charges poorly reflect how costs are imposed on the system.[166] Most of the distribution system is shared by multiple customers. However, all usage does not have the same impact on the system. It is the "maximum simultaneous demand of all customers using a shared piece of equipment that drives the costs associated with shared equipment, not an individual customer's maximum demand during any hour of the day. For example, if a customer's peak demand occurs at 2 am, this demand likely has little impact on distribution capacity needs because overall demand is low during overnight hours."[167]

Second, Sierra Club witness Shenstone Harris critiqued the use of non-coincident peak demand charge for these rates. Ms. Shenstone-Harris noted that a class non-coincident peak demand is a reasonable cost allocator for most distribution system costs in a cost-of-service study, but an individual customer's non-coincident demand is generally not reasonable as an element in rate design.[168] That is because a customer's individual non-coincident peak demand may occur at an entirely different time than the class non-coincident peak demand. Ms. Shenstone-Harris noted that a non-coincident demand charge may be appropriate for the recovery of distribution equipment that is sized specifically to meet an individual customer's maximum demand whenever that occurs (e.g., a

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164 Shenstone-Harris Dir. Test. at 58:20-59:2.
165 Shenstone-Harris Dir. Test. at 58:20-59:2.
166 Shenstone-Harris Dir. Test. at 59:19-60:26.
167 Shenstone-Harris Dir. Test. at 59:22-60:4.
168 Shenstone-Harris Dir. Test. at 60:7-12.

transformer sized specifically to a customer's individual demand), but are not appropriate for recovering costs associated with equipment that is shared by multiple customers, such as feeders and substations.[169] Moreover, non-coincident demand charges simply encourage customers to spread their charging evenly over the course of the day, which could have the perverse incentive of encouraging some charging to shift from off-peak to on-peak hours to flatten demand, despite the system facing capacity constraints only during on-peak hours.[170]

Ms. Shenstone-Harris recommended that the Commission modify the DT rate tariff to one of two alternatives that are more cost-reflective than non-coincident demand charges. First, a time-limited demand charge that applies only during certain hours of the day reflects costs on the system more accurately, as it is assessed only during hours in which the system tends to be stressed.[171] For example, "if Duke feeder and substations typically peak between the hours of 4 pm and 8 pm, a demand charge might be designed to only apply during these hours as this would more closely approximate a customer's contribution to distribution capacity costs than a non-coincident demand charge."[172]

Also and with greater emphasis, Ms. Shenstone Harris recommended that the Commission modify the DT rate tariff to one of time-varying volumetric charges.[173] Whereas a demand charge only measures a customer's highest demand during the month, a time-varying rate also accounts for the duration of that demand.[174] Accounting for the length of time that a customer uses shared equipment is important, as that impacts the ability of other customers to also use that equipment. By accounting for the volume of usage of a customer during hours when the system is stressed, a time-

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169 Shenstone-Harris Dir. Test. at 60:21-26.
170 Shenstone-Harris Dir. Test. at 62:11-15.
171 Shenstone-Harris Dir. Test. at 61:5-12.
172 Shenstone-Harris Dir. Test. at 61:7-9.
173 Shenstone-Harris Dir. Test. at 61:13-18.
174 Shenstone-Harris Dir. Test. at 59:22-60:4.

varying volumetric rate better reflects the fact that customer demand stresses the distribution system in the same manner, because some customers usage precludes other customers from using the same equipment.[175] A demand charge cannot account for this impact but a volumetric rate does account for how different usage stresses the system in different ways. The Commission should thus modify Duke's DT Rate so that it is time-varying volumetric charge instead of a non-coincident peak rate.

C. The Commission Should Modify Duke's Rider LM so that It is a Time-Varying Volumetric Charge instead of a Non-Coincident Peak Rate.

For Rider LM, Duke proposed to change the measurement of billed demand for Rider LM for Rates DS and DP (Distribution Secondary and Distribution Primary for customers with demand <500 kW).[176] Currently Rider LM measures billed demand only during on-peak hours. The Company's proposal would change the definition of billed demand to be the greater of demand measured during on-peak hours or 50 percent of off-peak hours.[177]

Witness Shenstone-Harris explained that the proposed change would result in less efficient use of the system. Specifically, a demand charge that applies during off-peak hours would reduce the incentive for customers to shift as much load to off-peak hours as possible. Instead, customers would face a perverse incentive to shift some charging from off-peak to on-peak hours to create a flatter load profile, despite the system facing capacity constraints only during on-peak hours.[178]

In addition, Ms. Shenstone-Harris explained that the proposed change to Rider LM will have customers paying too much for charging during off-peak hours, resulting in lower adoption of EVs and inefficient use of the system. As discussed above for Rate DT, the costs associated with shared distribution system equipment are driven by the maximum simultaneous demand of multiple

175 Shenstone-Harris Dir. Test. at 61:19-62:10.
176 Shenstone-Harris Dir. Test. at 65:22-24.
177 Shenstone-Harris Dir. Test. at 66:1-3.
178 Shenstone-Harris Dir. Test. at 66:21-26.

customers, not individual customers.[179] During off-peak hours, system demand is low, leaving substantial spare capacity to serve off-peak load. Such a change is unnecessary as the terms and conditions in the tariff protects the Company from customers imposing excessive demand during off-peak hours without paying for any necessary upgrades to serve that demand.[180] The proposed changes will result in customers paying too much for off-peak EV charging. Which will in turn raise the costs of fleet electrification for customers who charge during off-peak hours and it would slow transportation electrification in general.[181]

EV rates should encourage customers to charge in a manner that minimizes additional grid investments, which is done by encouraging charging during off-peak hours. This helps provide the greatest benefits to all customers. To ensure that the Rider LM rate achieves this goal, the Commission should reject the Company's proposed modification and require the Company to maintain the application of demand charges under Rider LM to on-peak hours only, as this would be more cost- reflective and better support transportation electrification.

CONCLUSION

The Commission should align the depreciation rate for East Bend with an anticipated retirement date of 2030, require Duke to analyze the effects of the new statutory and regulatory landscape in its next IRP, and modify the EV tariffs to incentivize off-peak charging.

179 Shenstone-Harris Dir. Test. at 66:9-20.
180 Shenstone-Harris Dir. Test. at 66:9-20.
181 Shenstone-Harris Dir. Test. at 66:9-20.

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of Sierra Club's post-hearing brief in this action is being electronically transmitted to the Commission on June 9, 2023, and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

/s/ Joe F. Childers
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