COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC., FOR: 1) AN ADJUSTMENT OF THE 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. 2024-00354

DUKE ENERGY KENTUCKY, INC.'S INITIAL POST-HEARING BRIEF

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), by counsel, pursuant to the May 30, 2025, Order of the Kentucky Public Service Commission (Commission), and other applicable law, hereby tenders to the Commission its Initial Post-Hearing Brief (Brief), respectfully stating as follows:

I. INTRODUCTION

Duke Energy Kentucky's proposed increase in base rates in this case will result in fair, just, and reasonable rates charged to consumers while balancing the utility's ongoing need to access capital on reasonable terms. Duke Energy Kentucky's current electric rates and charges, which are based on costs forecasted during the twelve months ended June 30, 2024, were ultimately authorized by this Commission by Order dated October 12, 2023,[1]

[1] *See* Case No. 2022-00372, *Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the 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*, Order (Ky. PSC Oct. 12, 2023).

and as amended on rehearing by Order dated July 1, 2024 in Case No. 2022-00372 (2022 Rate Case).[2]

Duke Energy Kentucky is proposing to increase annual electric base rate revenues by approximately $70 million or approximately 14.7 percent across all customer classes.[3] The Company is proposing new rates because its present base rates are no longer sufficient to enable the Company to furnish adequate, efficient, and reasonable service or have the opportunity to earn a fair rate of return on investments. A significant driver of the Company's requested rate increase is an increase in the Company's rate base as compared to that in the last rate case. Rate base has grown $157 million since the Company's 2022 Rate Case as a result of much needed investments made by the Company to enhance the safety, reliability, and resiliency of the electric system and to support localized economic development.[4] The return on this rate base, along with the associated depreciation expense, is the most significant driver of this case.[5]

Other drivers for this case include aligning depreciation rates with the estimated useful life of the East Bend Generating Station (East Bend). The Company is proposing in this case to adjust depreciation rates to reflect a December 31, 2038, retirement of East Bend as outlined in the Company's 2024 Integrated Resource Plan (IRP).[6] The Company is also requesting inclusion of terminal net salvage in depreciation expense for East Bend and its Woodsdale Generating Station (Woodsdale), consistent with established utility ratemaking principles.[7] The Company proposes to create two regulatory deferrals to

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[2] *See id.*, Rehearing Order (Ky. PSC July 1, 2024).
[3] Lisa D. Steinkuhl Rebuttal Testimony at 4 (Steinkuhl Rebuttal) (Apr. 9, 2025).
[4] Sarah E. Lawler Direct Testimony at 4 (Lawler Direct) (Dec. 2, 2024); Amy B. Spiller Direct Testimony at 20-21 (Spiller Direct) (Dec. 2, 2024).
[5] *Id.*
[6] *Id.*
[7] *Id.*

account for the differences between actual costs and the amounts forecasted in this rate case. The first deferral relates to planned generation outage operation and maintenance (O&M) expenses and the second deferral relates to forced outage replacement purchased power expense.[8] These proposed deferrals protect customers from overpaying for these costs when the utility's actual costs incurred are below the levels used to establish base rates, and conversely ensure the Company can recover its actual costs when the actual costs incurred are higher than those used to establish base rates.

The cost of capital has also increased since the Company's 2022 Rate Case.[9] The Company's current weighted average cost of capital (WACC) approved in the 2022 rate case is 7.192 percent. The Company is requesting a WACC of 7.968 percent in this current proceeding. The return on equity (ROE) authorized in the last electric rate case was 9.75 percent, with a 4.377 percent long-term debt rate and a 4.739 percent short-term debt rate.[10] In this proceeding, the Company is requesting a ROE of 10.85 percent, a 4.929 percent long-term debt rate and a 3.197 percent short-term debt rate.[11]

Duke Energy Kentucky's Application requested an increase in annual base electric revenue of $70,008,476 million.[12] In its direct testimony, the Office of Attorney General (OAG) proposed several adjustments to rate base and operating income and proposed a lower ROE of 9.65 percent.[13] In rebuttal testimony, the Company accepted two of the

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[8] Lawler Direct at 10.
[9] Lawler Direct at 8-9.
[10] *Id.*
[11] Thomas J. Heath Direct Testimony at 17(Heath Direct) (Dec. 2, 2024).
[12] Lisa D. Steinkuhl Direct Testimony at 5 (Steinkuhl Direct) (Dec. 2, 2024).
[13] Lane Kollen Direct Testimony (Kollen Direct) (Mar. 5, 2025); Randy Futral Direct Testimony (Futral Direct) (Mar. 5, 2025); Richard Baudino Direct Testimony (Baudino Direct) (Mar. 5, 2025).

OAG's adjustments.[14] As a result of these two adjustments, Duke Energy Kentucky's revised revenue requirement increase is $69,986,788 as shown in the table below.[15]

Table 1. Duke Energy Kentucky's Rebuttal Revenue Requirement

Line No.	Summary		Impact to Revenue Deficiency
1	**Duke Energy Kentucky Initial Request**	$	70,008,476
2	Cash Working Capital		(5,101)
3	DEBS EDIT Amortization		(16,587)
4	**Total Adjustments to Company's Proposed Revenue Requirement**	$	(21,688)
5	**Duke Energy Kentucky Revised Revenue Increase Request**	$	69,986,788

As described in further detail below, the remaining adjustments proposed by the OAG should be rejected and the Commission should approve the Company's requested increase in base rates because it is reasonable and amply supported by record evidence in this proceeding.

In this rate case, the Company also proposed several new customer enhancements or programs that, if approved, will improve customers' experience and the Company's provision of service to its customers. These new enhancements or programs include: a fee-free card payment proposal for customers, a new power hedging program, and a proposal to manage natural gas surplus for electric generation.[16] Each of these proposals is fully supported by the administrative record in this case, and the Company respectfully requests approval of each of these items, in addition to the increase in base rates set forth above, and the other items requested in this Brief.

[14] Steinkuhl Rebuttal at 3-4.
[15] Steinkuhl Rebuttal at 4.
[16] Spiller Direct at 21.

II. BACKGROUND

A. Overview of Duke Energy Kentucky

Duke Energy Kentucky is a wholly owned subsidiary of Duke Energy Ohio, Inc. (Duke Energy Ohio), which is itself a wholly owned subsidiary of Cinergy.[17] Cinergy is wholly owned by Duke Energy Corporation (Duke Energy).[18]

1. Customers and Service Territory

Duke Energy Kentucky is an operating utility engaged in the natural gas and electric business. Duke Energy Kentucky generates electricity, which it distributes and sells to approximately 155,000 customers in Boone, Campbell, Grant, Kenton, and Pendleton counties in Kentucky.[19] The Company also provides natural gas service in Bracken, Boone, Campbell, Gallatin, Grant, Kenton, and Pendleton counties to approximately 105,000 customers.[20]

2. Generation, Transmission, and Distribution Facilities

a. East Bend Generating Station

First commissioned in 1981, East Bend is a 600 megawatt (MW) (net summer rating) coal-fired steam unit located along the Ohio River in Boone County, Kentucky.[21] The station has river facilities to allow barge deliveries of coal and lime.[22] East Bend is designed to burn eastern bituminous coal and achieved a net plant heat rate of 11,075 Btu/kWh for calendar year 2023.[23] The major pollution control features at East Bend include a high-efficiency hot side electrostatic precipitator, a selective catalytic reduction

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[17] *Id.* at 5.
[18] *Id.*
[19] *Id.* at 4.
[20] *Id.*
[21] William Luke Direct Testimony at 3 (Luke Direct) (Dec. 2, 2024).
[22] *Id.*
[23] *Id.*

control (SCR) system designed to reduce nitrogen oxide (NO_x) emissions by 85 percent, and a Wet Flue Gas Desulfurization (WFGD) system designed to remove sulfur dioxide ($S0_2$) emissions to an average of 97 percent.[24] The station's electrical output is directly connected to the Duke Energy Midwest (consisting of Kentucky and Ohio) 345 kilovolt (kV) transmission system.[25]

Although East Bend is approaching the end of its service life and the Company plans to replace the asset with other resources, the Company continues to make investments to maintain East Bend's reliability through its service life to support the energy needs of the Company's customers.[26] The Company follows a regular maintenance schedule at East Bend, which generally consists of periodic maintenance activities performed during off-peak seasons in the spring and/or fall.[27] Outage duration varies depending on maintenance project scope, which is determined using various techniques like conditions assessments, operational data, and Original Equipment Manufacturer (OEM) recommendations.[28]

b. Woodsdale

Woodsdale is a six-unit, simple cycle, combustion turbine (CT) station located in Butler County, Ohio with a collective net winter rating of 564 MW and a net summer rating of 476 MW.[29] Woodsdale is designed to provide peaking service and to have black start and dual fuel capability.[30] Woodsdale is connected to the Texas Eastern Transmission Company (TETCO) interstate pipeline that transports natural gas to supply the station.[31]

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[24] *Id.*
[25] *Id.*
[26] *Id.* at 4.
[27] *Id.*
[28] *Id.*
[29] *Id.* at 7.
[30] *Id.*
[31] *Id.* at 8.

The design of Woodsdale as a peaking unit with low capacity factors does not support acquiring firm natural gas transportation through the available natural gas interstate pipelines.[32]

The Company follows periodic maintenance cycles for Woodsdale similar to those of East Bend.[33] Since the 2022 Rate Case, the Company has made necessary investments to ensure the reliability of Woodsdale through its useful life, including generator field rewinds and a major turbine inspection and overhaul.[34]

c. Solar Generating Facilities

Duke Energy Kentucky owns four solar facilities with a total nameplate rating of 8.8 MW: Walton 1 Solar Plant, located in Walton, Kentucky; Walton 2 Solar Plant, also located in Walton, Kentucky; Crittenden Solar Plant, located in Dry Ridge, Kentucky; and Aero Solar Plant, located in Burlington, Kentucky.[35] These four plants combined provide 3.7 MW of firm summer capacity. The Walton and Crittenden Solar sites have commercial operation dates of December 14, 2017, while the Aero Solar site went into commercial operation on March 22, 2023.[36]

d. Miami Fort 6 Generating Facility (Miami Fort 6)

While Miami Fort 6 officially retired from commercial operation on June 1, 2015, Duke Energy Kentucky continues to ensure that its facilities are decommissioned in a safe and reasonable manner.[37] Because of the close proximity of Miami Fort 6 and shared facilities with other Miami Fort station generating units that are still in operation, the

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[32] *Id.*
[33] *Id.* at 9.
[34] *Id.* at 10.
[35] *Id.*
[36] *Id*.
[37] *Id.*

Company cannot immediately perform all necessary decommissioning and demolition work.[38]

e. Transmission Facilities

Duke Energy Kentucky owns, operates, and maintains approximately 126 miles of transmission lines operating at 69 kV.[39] The Duke Energy Kentucky electric system is interconnected with East Kentucky Power Cooperative, Inc.'s system via a 69 kV tie line at the Kenton substation.[40] Duke Energy Kentucky's electric delivery systems include various other equipment and facilities.[41] Duke Energy Kentucky's electric delivery system provides considerable flexibility for Duke Energy Kentucky to operate in a manner that provides reliable and economic power to its customers.[42]

Duke Energy Kentucky's electric transmission system has grown considerably.[43] In the Company's 2022 Rate Case, Duke Energy Kentucky's forecasted cost of electric transmission system plant in service was $134,522,697 (thirteen-month average forecasted balance ending June 30, 2024).[44] However, as of June 30, 2024, Duke Energy Kentucky's actual cost of electric transmission system plant in service was $139,279,748.[45] The Company's forecasted test year (thirteen-month average balance ending June 30, 2026) in this case is projecting the balance to be $160,703,839.[46]

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[38] *Id.*
[39] Marc W. Arnold Direct Testimony at 3 (Arnold Direct) (Dec. 2, 2024).
[40] *Id.*
[41] *Id.*
[42] *Id*. at 4.
[43] *Id*. at 5.
[44] *Id.*
[45] *Id*.
[46] *Id.*

f. Distribution Facilities

The Company's distribution system is comprised of approximately 2,248 miles of primary distribution lines operating at 34.5 kV or lower and approximately 755 miles of secondary distribution circuits operating at 480 volts or below.[47] The delivery system also includes approximately 39 combined transmission and distribution substations with a combined capacity of approximately 3,844,000 kV and various other equipment and facilities.[48]

Duke Energy Kentucky is making substantial investments in its distribution system. In the Company's 2022 Rate Case, Duke Energy Kentucky's forecasted cost of electric delivery system plant-in-service was $692,963,750 (thirteen-month average forecasted balance ending June 30, 2024).[49] However, as of June 30, 2024, Duke Energy Kentucky's actual cost of electric distribution system plant-in-service was $707,234,216.[50] The Company's forecasted test year (thirteen-month average balance ending June 30, 2026) in this case is projected to be $799,139,727.[51] While load growth across the entire Duke Energy Kentucky system has been consistent, localized load growth has had a significant impact upon the Company and is driving the current and near-term investments.[52] The Company continues to make investments focused on maintaining and improving reliability in its electric delivery system.[53]

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[47] *Id.* at 3.
[48] *Id.*
[49] *Id.* at 4.
[50] *Id.*
[51] *Id.*
[52] *Id.* at 5-6.
[53] *Id.* at 6.

3. Community Engagement

Duke Energy Kentucky prides itself on its community engagement and its work to promote economic development in the communities in which it does business. In 2024, Site Selection Magazine named Duke Energy one of its Top Utilities in Site Selection for North America for the twenty-first consecutive year.[54] Since 2011, Duke Energy's Urban Revitalization Initiative has provided over $3.4 million to 110 projects in the Duke Energy Kentucky and Duke Energy Ohio service areas.[55] Approximately half of that funding has gone to projects in Northern Kentucky.[56]

Since 2016, Duke Energy Kentucky and the Duke Energy Foundation have contributed over $6.6 million in shareholder dollars to charitable organizations in Kentucky.[57] The Company also encourages its employees to directly engage in community improvement projects; indeed, since 2016, over 500 Company employees and retirees, along with their families, have volunteered over 18,000 hours of their time to help local neighbors.[58]

Duke Energy Kentucky has a long history of Company, customer, and employee support for low-income customers, such as the Share the Light Fund, which allows Duke Energy Kentucky to aid qualifying customers struggling to pay their energy bills.[59] Duke Energy Kentucky also participates in Home Energy Assistance, a program that provides monthly bill assistance for eligible customers and offers Neighborhood Energy Saver Program, an energy efficiency initiative for lower income customers.[60] Additionally, the

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[54] Spiller Direct at 8.
[55] *Id.* at 9.
[56] *Id.* at 9-10.
[57] *Id.* at 12.
[58] *Id.*
[59] *Id*. at 13.
[60] *Id*. at 13-14.

Payment Plus program is available to qualifying residential customers and provides the opportunity to receive a $500 reduction of their utility bill.[61]

4. Customer Satisfaction and Expectations

Duke Energy Kentucky is constantly looking for ways to improve its customers' experience. Over the past several years, the Company has developed and implemented a variety of programs to interact with customers and make the process of managing and paying their bills more convenient.[62] The Company uses different resources to stay informed as to overall customer satisfaction including the Customer Experience Monitor survey (CX Monitor Survey) and Fastrack, Duke Energy's proprietary post-transaction customer satisfaction measurement tool.[63] The results have been consistently good, and indeed, have improved over time.[64]

5. Developments Since the 2022 Rate Case

The Company forecasts in this case that it will invest $250 million more in additional electric infrastructure than what was forecasted in its last base electric rate case filed in 2022. These investments will enhance the safety, reliability, and resiliency of its electric system.[65] Duke Energy Kentucky is experiencing significant development in Northern Kentucky and continues to make necessary investments to existing facilities to maintain reliability.[66]

Looking forward, the Company continues to explore strategies to improve the services provided to customers and the overall performance of the electric delivery

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[61] *Id.*
[62] *See id.* at 15–20 (describing opportunities available to customers to engage with the Company and ensure customer satisfaction).
[63] *Id.* at 15.
[64] *See id.* at 16-19.
[65] *Id*. at 20.
[66] *Id.*

system.[67] Further, the Company continues to evaluate opportunities to make prudent investments in new technologies that provide value to customers.[68]

B. Procedural History

Duke Energy Kentucky filed its Notice of Intent to File an Application for the Adjustment of Electric Rates on November 1, 2024. The Application was filed on December 2, 2024. The Commission issued a No Deficiency Letter on December 9, 2024. Proof of publication of customer notice was filed on March 18, 2025.

The OAG, The Kroger Co. (Kroger), and Walmart Inc. (Walmart), moved to intervene on December 15, 2024, December 19, 2024, and January 2, 2025, respectively. The Commission granted OAG's motion on December 11, 2024; Kroger's motion on January 16, 2025; and Walmart's motion on January 17, 2025.[69]

On February 7, 2025, the Commission issued an Order setting a formal hearing on Duke Energy Kentucky's Application to commence on May 21, 2025. The Company filed a copy of its Request for Publication of Hearing Notice on April 17, 2023, and filed its Proof of Publication of Hearing Notice on May 20, 2025. A formal hearing was held from May 21 through May 22, 2025 at the Commission's offices in Frankfort, Kentucky. In all, 23 witnesses took the stand on behalf of Duke Energy Kentucky, and five cumulative witnesses testified on behalf of the Intervenors. Following the hearing, Duke Energy Kentucky responded to additional Post-Hearing Requests for Information from the Commission Staff and the OAG.

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[67] *Id*.
[68] *Id*.
[69] OAG, Walmart, and Kroger are each referred to herein as an "Intervenor."

III. ARGUMENT

A. Jurisdiction and Standard of Review

Duke Energy Kentucky is a "utility" under KRS 278.010(3) and is therefore subject to the Commission's jurisdiction under KRS 278.040.[70] The Commission is a creature of statute and has only such powers granted to it by the General Assembly.[71] The Commission's jurisdiction is therefore limited to the "rates" and "services" of the Company.[72] The Kentucky Supreme Court has noted that "rates are merely the means designed for achieving a predetermined objective, which in this instance was how much additional revenue should the Company be allowed to earn."[73] The Company's rates may be increased pursuant to the procedures set forth in KRS 278.180, 278.190, and 278.192, and the Commission regulations promulgated thereunder.

It is well-established that "[t]he manifest purpose of the Public Service Commission is to require and insure fair and uniform rates, prevent unjust discrimination, and prevent ruinous competition."[74] In undertaking the rate-making process, "the Commission has discretion in working out the balance of interests necessarily involved and . . . it is not the

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[70] Application of Duke Energy Kentucky, Inc. (Application), at 2 (Dec. 2, 2024).

[71] *See Boone Co. Water and Sewer District v. Public Service Comm'n*, 949 S.W.2d 588, 591 (Ky. 1997); *Simpson County Water Dist. v. City of Franklin*, 872 S.W.2d 460, 462 (Ky. 1994); *Com., ex rel. Stumbo v. Kentucky Public Service Comm'n*, 243 S.W.3d 374, 378 (Ky. Ct. App. 2007); *Cincinnati Bell Telephone Co. v. Kentucky Public Service Comm'n*, 223 S.W.3d 829, 836 (Ky. Ct. App. 2007); *Public Service Comm'n v. Jackson Cnty. Rural Electric Coop., Inc.*, 50 S.W.3d 764, 767 (Ky. Ct. App. 2000), as modified (July 21, 2000).

[72] *See Public Service Comm'n v. Blue Grass Natural Gas Co.,* 197 S.W.2d 765, 768 (Ky. 1946) ("We have held that the jurisdiction of the Public Service Commission is clearly and unmistakably limited to the regulation of rates and service of utilities.") (citing *Smith v. Southern Bell Telephone and Telegraph Co.,* 104 S.W.2d 961 (Ky. 1937)); *Benzinger, et al, v. Union Light, et al,* 170 S.W.2d 38 (Ky. 1943); *Peoples Gas Co. of Kentucky v. City of Barbourville,*
165 S.W.2d 567 (Ky. 1942).

[73] *Kentucky Power Co. v. Energy Reg. Comm'n*, 623 S.W.2d 904, 908 (Ky. 1981).

[74] *Simpson County*, 872 S.W.2d at 464 (citing *City of Olive Hill v. Public Service Comm'n*, 203 S.W.2d 68 (Ky. 1947)).

method, but the result, which must be reasonable."[75] The Commission has considerable discretion to take into account the multitude of factors affecting the rates of a utility. Indeed, the Kentucky Court of Appeals commented upon the breadth of this discretion, stating:

> It is certainly broad enough to consider such things as replacement cost, debt retirement, operating cost, and at least some excess capacity in order to insure continuation of adequate service during periods of high demand and some potential for growth and expansion. It also allows for consideration of whether expansion investments were prudently or imprudently made, and whether a particular utility is investor owned or a cooperative operation. Any of these factors might be extremely significant in varying situations when determining what ultimately would be a fair, just and reasonable rate and would allow for a balancing of interests.[76]

However, the Commission ultimately must approve rates that are "fair, just and reasonable."[77] Accordingly, approved rates must "enable the utility to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed."[78] By contrast, an unreasonable rate "has been construed in a rate-making sense to be the equivalent of confiscatory."[79] In considering the rates to be authorized herein, the Commission must consider both the present and the future impact of such rates upon the Company's financial condition—not only to avoid confiscation, but to support Duke Energy Kentucky's financial condition and avoid a credit downgrade that will

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[75] *Kentucky Indus. Utility Customers, Inc. v. Kentucky Utilities Co.*, 983 S.W.2d 493,498 (Ky. 1998) (citing *Federal Power Comm'n v. Hope Natural Gas*, 320 U.S. 591 (1944)); *see also National-Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 785 S.W.2d 503, 515 (Ky. App. 1990) (citing *Louisville & Jefferson County Met. Swr. Dist. v. Joseph E. Seagram & Sons*, 211 S. W.2d 122 (Ky. 1948)).
[76] *National-Southwire Aluminum Co.*, 785 S.W.2d at 512.
[77] KRS 278.030(1).
[78] *National-Southwire Aluminum Co.*, 785 S.W.2d at 512–13 (quoting *Commonwealth ex rel. Stephens v. South Central Bell Tel. Co.*, 545 S.W.2d 927, 930–31 (Ky. 1976)).
[79] *Public Service Comm'n of Kentucky v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986).

increase the costs of Company borrowing on behalf of customers.[80] It is critically important for Duke Energy Kentucky to obtain reasonable, supportive credit metrics to maintain strong credit quality.[81] As the Applicant, the Company bears the burden of proof.[82]

1. Base Period, Forecasted Test Year Expenses

For the current rate case, the Company used a base period of the 12 months ending February 28, 2025, which consists of six months of actual data from March 1, 2024 through August 31, 2024, and six months of budgeted data from September 1, 2024 through February 28, 2025.[83] The Company also used a fully forecasted test period spanning the twelve-month period ending on June 30, 2026.[84] The forecasted test year data was developed by using the Company's standard forecasting methods.[85] In accordance with KRS 278.192(2)(b), the Company filed its updated base period data on April 14, 2025. The Company also made appropriate adjustments based upon known and measurable factors and appropriately normalized and annualized the forecasted data. In conformity with Commission regulations,[86] the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by the Company's management.[87] No intervenor objected to the Company's proposed test year period or suggested an alternative test period, therefore the Commission should accept the forecasted test period proposed by Duke Energy Kentucky in this proceeding.

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[80] *Dewitt Water District*, 720 S.W.2d at 730 ("When considering the concept of confiscation, the future as well as the present must be considered. It must be determined whether the rates complained of are yielding and will yield a sum sufficient to meet operating expenses.") (citing *McCardle v. Indianapolis Water Company,* 272 U.S. 400 (1926)).
[81] *See generally* Heath Direct.
[82] *See Energy Regulatory Comm'n v. Kentucky Power Co.*, 605 S.W.2d 46, 49 (Ky. App. 1980) (citing *Lee v. International Harvester Co.*, 373 S.W.2d 418 (Ky. 1963)).
[83] Grady "Tripp" S. Carpenter Direct Testimony at 3 (Carpenter Direct) (Dec. 2, 2024).
[84] *Id.*
[85] *See id.* at 3–13 (describing the Company's standard forecasting methodology in significant detail).
[86] 807 KAR 5:001, Section 16(7)(e)(2).
[87] Carpenter Direct at 13.

The OAG was the only intervenor to recommend adjustments to Duke Energy Kentucky's proposed revenue requirement. The Company addresses each of the OAG's proposed adjustments in the following "Rate Base" and "Operating Income and Deferrals" sections of this Brief.

2. Rate Base

a. Cash Working Capital Calculation

Cash Working Capital (CWC) refers to the amount of cash a business needs to fund its day-to-day operations, considering the timing differences between cash inflows and outflows. CWC recognizes that cash supplied by shareholders, on behalf of the utility's customers, may be needed to finance operating costs incurred between when a utility disburses cash to vendors in its accounts payable and when revenues are collected from customers for accounts receivable.

The Company prepared a lead-lag study to determine its CWC requirements in this case. A lead-lag study is a detailed analysis used to calculate CWC by comparing the timing of cash inflows (revenue collection) with cash outflows (payment of expenses). In particular, the Company analyzed the lag time between the date customers receive service and the date customers' payments are received, processed, and available to the Company, offset by the lead time during which the Company receives goods and services that are paid for at a later date.[88] Duke Energy Kentucky performed its lead-lag study based on the most recent calendar year (*i.e.*, the twelve months ended December 31, 2023) and excluded all noncash items and balance sheet adjustments.[89]

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[88] Michael J. Adams Direct Testimony at 3-4 (Adams Direct) (Dec. 2, 2024).
[89] Adams Direct at 4-5.

i. Coal Fuel and Lime Expenses

The Company purchases lime and coal inventories from various suppliers on a routine basis. Payments for these purchases are typically due within 15 days. The Company computed a dollar-weighted lead for these lime and coal inventories as part of its CWC analysis based on actual amounts paid and payment dates during the study period, calendar year 2023.[90] The lead for lime and coal inventories reflects the amount of time between when Duke Energy Kentucky receives coal and lime purchases and when the Company is required to pay for those purchases.

OAG witness Lane Kollen recommended that the Company be required to exclude coal fuel and lime expense from its calculation of CWC, arguing that these items represent "non-cash" expenses used from the inventories included in rate base.[91] Mr. Kollen reasoned that because there is not a second cash disbursement or financing requirement when coal and lime inventories are used and expensed, the coal and lime expense should be removed from CWC calculation.[92]

In rebuttal testimony, Company witness Michael J. Adams explained that the coal fuel and lime expenses included in the CWC calculation are not non-cash items. Instead, the Company expends cash at the time it purchases coal and lime, and the CWC requirement for these items reflects the actual cash outlays made during the study period.[93]

The inclusion of fuel inventory in rate base compensates the Company for maintaining physical inventories of coal and lime, which are necessary for reliable service. In contrast, the CWC adjustment computed through the lead-lag study compensates the

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[90] *Id.* at 15.
[91] Kollen Direct at 4-6.
[92] *Id.* at 12-13.
[93] Michael J. Adams Rebuttal Testimony at 3 (Adams Rebuttal) (Apr. 9, 2025).

Company for cash flow timing differences — specifically, the period between when cash is paid for coal and lime and when cash is received from customers. The inclusion of coal and lime inventories in rate base does not eliminate the cash flow lag, as the value of inventory in rate base is static based on the average inventory levels while cash outflows for coal and lime purchases occur continuously and recovery of those costs occurs later (*i.e.*, there is a lag between when payments are made for inventories and when those costs are collected from customers through rates). The lead-lag study reflects actual, empirical data on timing differences, demonstrating that coal and lime cash outflows precede revenue collections. Excluding coal fuel and lime expense from the CWC calculation would unreasonably understate the Company's cash needs.

Further, the Company's removal of cost-free vendor financing supports the reasonableness of including coal and lime payments in the CWC calculation, as it isolates the utility's actual cash outlay for coal and lime purchases. With vendor credit excluded from rate base, the cash working capital requirement reflects the actual timing lag between when the utility pays for coal and lime and when it recovers those costs from customers — a lag that must be financed by the utility and therefore merits recovery.

ii. Amortization of Prepayments

In direct testimony, OAG witness Mr. Kollen also recommended that the Company be required to exclude amortization of prepayments recorded on the balance sheet from its CWC calculation.[94]

[94] Kollen Direct at 4-6.

In rebuttal testimony, Company witness Mr. Adams clarified that "[i]n actuality, the amortization of prepayments recorded on the balance sheet was not included in the CWC calculation."[95]

Because the Company has not included the amortization of prepayments recorded on the balance sheet in its CWC calculation, no adjustment is required.

iii. Long-Term Debt Interest Expense

In his direct testimony, OAG witness Mr. Kollen also recommended that the Commission include long-term debt interest expense in the Company's CWC analysis.[96] According to Mr. Kollen, long-term debt interest is paid in cash or the electronic funds transfer equivalent of cash on a lagged basis and therefore should be included in the CWC analysis.[97]

In rebuttal, Mr. Adams explained that exclusion of interest expense from the CWC analysis in this case is consistent with the CWC analysis approved in the Company's most recent electric base rate case proceeding, Case No. 2022-00372.[98] When preparing the lead-lag study for Duke Energy Kentucky for this rate proceeding, Mr. Adams confirmed that the Commission had, in prior rate proceedings, excluded long-term interest expense from the determination of Duke Energy Kentucky's CWC requirement.[99] As such, the Company proposed a similar treatment in this proceeding.[100] Mr. Adams further explained that the Company's treatment of interest expense in this case is consistent with regulatory theory and the practice adopted most commonly for lead-lag studies.[101] In particular, as described

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[95] Adams Rebuttal at 4.
[96] Kollen Direct, at 16.
[97] *Id.* at 13.
[98] Adams Rebuttal at 5.
[99] *Id.* at 7.
[100] *Id.* at 7-8.
[101] *Id.* at 6.

by Mr. Adams, the most common approach to interest expense in the analysis of CWC is to "not consider the operating income component in the lead-lag study, which results in not recognizing a need for cash working capital to cover operating income and not recognizing accruals of interest and preferred dividends as a source of cash working capital."[102] Further, "even if interest expense is included in the lead-lag study, it is only as an offset to the lag on operating income, which *increases* [CWC]."[103]

CWC is intended to cover the timing difference between operating cash outflows and inflows (*e.g.*, payroll, fuel, O&M expenses versus customer collections). Long-term debt interest is a financing cost, not an operating cost. As a result, exclusion of the timing of when long-term debt interest is paid from the lead-lag study is reasonable and appropriate and no adjustment to the Company's CWC is warranted.

iv. Collection Lag Days

As noted above, the Company calculated CWC by a lead lag study that analyzed the lag time between the date customers receive service and the date customers' payments are received, processed, and available to the Company, offset by a lead time during which the Company receives goods and services that are paid for at a later date.[104] The Company performed its lead-lag study based on the 12 months ended December 31, 2023, and excluded all noncash items and balance sheet adjustments.[105] The calendar year 2023 study period reflects the most current year of data available at the time the Company filed its case and appropriately reflects the current practices and timing of the provisioning/receipt of goods and services and the payment for such goods and services. The leads and lags were

[102] *Id.* (citing Robert L. Hahne and Gregory E. Aliff, Accounting for Public Utilities § 5.04[2][b][vii] (2022)).
[103] *Id.*
[104] Adams Direct at 3-4.
[105] *Id.* at 4-5.

applied to the Company's level of expenses and revenues for the forecasted test period (12 months ending June 30, 2026).

Revenue lag, which reflects the number of days from the date service is rendered until payment is received and funds are available to the Company, includes four components – service lag, billing lag, collection lag, and payment processing lag. The collection lag refers to the average amount of time from the date Duke Energy Kentucky issues a bill to a customer to the date that the Company receives payment from that customer. The Company computed the collection lag using accounts receivable aging data for the study period, calendar year 2023. Based on the analysis of this data, Duke Energy Kentucky's average collections lag was determined to be 26.66 days.[106] The Company computed total revenue lag days of 45.52 including service lag, billing lag, collection lag, and payment processing lag.[107]

In direct testimony, OAG witness Randy A. Futral concluded that while the service lag and billing lag computed by the Company seemed reasonable, the collection lag, which the Company computed to be 26.66 days, "seemed high."[108] Mr. Futral therefore recommended that the Commission use the 2024 collection lag days of 23.15 days instead of the filed 2023 collection lag days of 26.66 days.[109] Mr. Futral asserts, without basis, that "[t]he 2024 data is a more reasonable and recurring level of historic collection data that should be used to set the level of collection lag days," noting that 2023 receivables

[106] *Id.* at 7-8.
[107] *Id.* at 8.
[108] Futral Direct at 14.
[109] *Id.* at 16.

data likely was impacted by a short-term spike in natural gas commodity prices prior to the start of 2023.[110]

In rebuttal testimony, Company witness Mr. Adams responded, noting that Mr. Futral provided no basis or support for his assessment that the Company's collection lag of 26.66 days is unreasonable. Nor does Mr. Futral provide support for his determination that the 2024 collection lag is "more reasonable."[111] A CWC study, as well as a rate test year should reflect data from a matching period. The collection lag should not be arbitrarily singled out and adjusted to reflect a different period of time. If the study period needs to be adjusted, both the revenue lag and expense leads should be adjusted to reflect a matching of periods as well as any changes from the study period.[112]

The OAG's proposed adjustment ignores the matching concept of a study period. A CWC analysis should match the timing of cash flows over a given period. The analysis should be based on consistent time periods and should not rely on selective, single-point adjustments intended to produce a predetermined outcome, as such an approach is improper and results-oriented.

When questioned by Commission staff during the hearing regarding his recommendation to use a different time period for the revenue collection lag days in the CWC calculation, OAG witness Mr. Futral stated that his recommendation to use 2024 data to compute the collection lag days in place of the 2023 data used by the Company was based on "an anomalous situation" of gas prices spiking at the end of 2021. Mr. Futral goes on to describe that gas prices increased at the end of 2021 through 2022 and "at the

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[110] *Id.*
[111] Adams Rebuttal at 9.
[112] *Id.*

beginning of 2023, gas prices started going down."[113] The Company's use of 2023 data therefore reflects a reasonable and representative period to analyze CWC. There is no evidence in the record that the timing of customer payments in calendar year 2023 are not representative of expected customer payment patterns going forward.

Additionally, the Company's revenue lag days in this case computed in the Company's lead-lag study *declined* from what the Commission approved as reasonable in the Company's last electric base rate case, Case No. 2022-00372.[114] In that proceeding, Duke Energy Kentucky computed a collection lag of 27.02 days based on a calendar year 2021 study period, which is 0.36 days less than the collection lag computed in this case. Given that decline, the OAG's blanket conclusion that the 2023 collection lag "seems high" or was impacted by a spike in gas prices that occurred through 2022 is unsupported and without merit. It is also worth noting that the 2021 data used to compute the 27.02 collection lag days in the Company's last case, which the Commission concluded was reasonable, relied on data prior to the rise in natural gas prices referenced by Mr. Futral as his only support to modify the period used to determine collection lag in this case.[115] In Case No. 2022-00372, the Commission rejected the OAG's recommendation that the revenue lag days should be reduced finding that "Duke Kentucky's revised lead/lag study provides a reasonable measure of cash working capital because it reflects the actual cash flows of Duke Kentucky's electric operations. . ."[116]

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[113] Futral Cross, HVR at 3:55 (May 22, 2025).
[114] Case No. 2022-00372, *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*, Order at 9-10 (Ky. PSC Oct. 12, 2023).
[115] Futral Cross, HVR at 3:55 (May 22, 2025).
[116] Case No. 2022-00372, *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*

A properly conducted lead-lag study evaluates the timing of cash flows — *e.g.*, how many days after providing service a utility receives payment — not the amount of the bills. A price spike may increase the size of bills, but that does not mean customers take longer to pay. The evidence in the record in this proceeding demonstrates that the Company's lead-lag study reasonably reflects the timing of payments, and that the collection lag is in the range of expectation based on historical data and the Company's most recent case. The OAG's recommendation to reduce the collection lag is unreasonable and unsupported, would result in a mismatch in data relied on in the lead-lag study, and should therefore be rejected.

v. Prudency of Termination of Accounts Receivable Program

Until March 2024, Duke Energy Kentucky was a party to an agreement with its sister utilities in Ohio and Indiana, and the Cinergy Receivables Company (CRC), which provided for debt financing collateralized by outstanding accounts receivables.[117] The substance of the program was to use the accounts receivable of Duke Energy Indiana, Duke Energy Ohio, and Duke Energy Kentucky as a security instrument to diversify the long-term debt raised by each of these entities.[118] The CRC accounts receivable financing arrangement isolated the accounts receivable from other assets of the utilities and structured a financing that relied on the strength of the accounts receivable rather than the creditworthiness of the utilities.[119] Duke Energy Kentucky traditionally raises debt capital from fixed-rate long-term private placement issuances. Lenders for these types of

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Assets and Liabilities and (4) All Other Required Approvals and Relief, Order at 9-10 (Ky. PSC Oct. 12, 2023).

[117] Heath Direct at 25-26.

[118] *Id.*

[119] *Id.* at 26.

financings are typically insurance companies, pension funds, and money managers.[120] The accounts receivable financing program provided Duke Energy Kentucky the opportunity to raise floating-rate debt funded by financial institutions. This financing method provided diversification of both the interest rates and lending institutions.[121]

In response to the Commission's order in Case No. 2022-00372[122] and a broader enterprise-wide analysis, Duke Energy evaluated all of its accounts receivable financing programs in late 2023 and early 2024.[123] The evaluation considered a comparison of the borrowing costs of the accounts receivable financing programs relative to other alternative forms of financing and the amount of administrative support required to monitor, maintain, and oversee the programs. This evaluation determined that, under current market conditions, the accounts receivable financing programs were no longer producing the financial benefits originally intended as compared to other alternative forms of financing and that the administrative support required for these programs was extensive.[124] As a result of this evaluation, Duke Energy decided to repay all outstanding borrowings under these programs and terminate the related credit agreements. The CRC accounts receivable financing program was terminated in March 2024 and all outstanding borrowings were repaid at that time.[125]

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[120] *Id.*
[121] *Id.*
[122] Case No. 2022-00372, *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*, Order at 10 (Ky. PSC Oct. 12, 2023) (concluding that the revenue requirement impact of redistributing the accounts receivable financing to Duke Kentucky's other capital components would be an increase of approximately $2.094 million, resulting in a net increase of approximately $417,000 ($0.417 million), but requiring that Duke Kentucky evaluate the benefit of securitization or factoring, and concluding that an adjustment may be made in the subsequent rate adjustment proceedings if the benefit of the arrangement does not outweigh the increase in cash working capital.).
[123] Heath Direct at 27.
[124] *Id.*
[125] *Id.*

In direct testimony, OAG witness Mr. Kollen recommended that the Commission impute the now-terminated receivables financing program by reflecting a purported cost savings based on a lesser collection lag days in the cash working capital calculation, thereby reducing working capital and rate base. Mr. Kollen argues the receivables financing program "accelerate[d] the conversion of the Company's receivables to cash, reducing the collection lag from 27.48 days to 1.46 days."[126] Mr. Kollen asserts that the Company's decision to terminate the receivables financing program in March 2024 was unreasonable and imprudent because it increased the cash working capital requirement due to longer collection lag days and increased the Company's debt costs.[127]

In rebuttal testimony, Company witness Thomas J. Heath explained the flaws in Mr. Kollen's understanding of the accounts receivable financing program, noting that "Mr. Kollen makes the same incorrect arguments regarding the accounts receivable financing program as he did in Case No. 2022-00372, which were rejected by the Commission in its Order in that case."[128] Mr. Kollen argued that Duke Energy Kentucky sold its receivables and collected payments from customers daily, akin to a factoring program. Duke Energy Kentucky explained that it engaged in the securitization financing of accounts receivable as a means of diversifying its long-term debt and not as factoring of accounts receivable.[129] Duke Energy Kentucky further explained that it only received cash after customers remitted payments.[130] Duke Energy Kentucky also argued that Mr. Kollen's recommendation would result in asymmetrical treatment of the accounts receivable

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[126] Kollen Direct at 21. The OAG recommends using 1.46 days for the collection lag days instead of the actual collection lag days included in the Company's cash working capital calculation adjusted for Witness Futral's recommendation to reduce the revenue lag days, discussed above. *See* Kollen Direct at 22-23.
[127] *Id.* at 19-20.
[128] Thomas J. Heath, Jr. Rebuttal Testimony at 3 (Heath Rebuttal) (April 9, 2024).
[129] *Id.*
[130] *Id.* at 3-4.

financing program as he did not propose any adjustment to remove this debt from Duke Energy Kentucky's embedded cost of debt.[131] The OAG's proposal is also inconsistent with how the accounts receivable financing program was historically treated by the Company and approved by the Commission in all previous orders since the program was implemented in 2002.[132]

Under the now terminated receivables financing program, Duke Energy Kentucky did not receive any cash immediately upon customer billing as asserted by the OAG. The Company did not receive cash until it was paid by its customers, which is properly reflected in the Company's lead-lag study in this case. As a result, neither collection lag nor revenue lag overall were impacted by the securitization financing.

It is important to note that the same arguments made by OAG in this proceeding were considered *and rejected* by the Commission in Duke Energy Kentucky's last electric rate case, Case No. 2022-00372, when the accounts receivable financing program was still in place. Even if the program had impacted cash working capital, which the Commission has already concluded it did not, it would be wholly inappropriate to impute impacts of a financing program that no longer exists.[133]

In Case No. 2022-00372, the OAG similarly recommended a reduction to the collection lag from the 27.02 days computed to 1.46 days to reflect what the OAG claimed were faster collections through the sale of accounts receivable. The Commission rejected the OAG's recommendation in that case, concluding that "Duke Kentucky's revised lead/lag study provides a reasonable measure of cash working capital because it reflects

[131] *Id.*
[132] *Id.* at 4.
[133] *Id.*

the actual cash flows of Duke Kentucky's electric operations, and the Attorney General's adjustment is not in the best interest of customers at this time."[134] The Commission has already rejected the flawed foundation of the OAG's position while the Company's receivables financing program was in place. The termination of that program does not validate the OAG's argument now. Adopting the proposed adjustment under these circumstances is not only unwarranted, but also fundamentally illogical.

Further, as detailed in the direct and rebuttal testimonies of Mr. Heath in this case, the decision to terminate the accounts receivable financing program was made after an evaluation that considered a comparison of the borrowing costs of the accounts receivable financing programs relative to other alternative forms of financing and the amount of administrative support required to monitor, maintain, and oversee the programs.[135] This evaluation determined that the accounts receivable financing program was no longer producing the financial benefits originally intended as compared to other alternative forms of financing and that the administrative support required for these programs was extensive.[136]

Notably, the Company's forecasted cost of short-term borrowings under the Duke Energy Utility Money Pool Agreement is 3.02 percent for the test period. In comparison, borrowing costs under the now terminated accounts receivable financing program would be considerably higher. Borrowing cost under the program approximated the Secured

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[134] Case No. 2022-00372, *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*, Order at 10 (Ky. PSC Oct. 12, 2023).
[135] Heath Direct at27; Heath Rebuttal at 10-11.
[136] *Id.*

Overnight Fund Rate plus 0.85 percent, or approximately 3.90 percent for the test period.[137] As short-term debt is included in the Company's capital structure, customers will receive the benefit of lower short-term debt costs resulting from the termination of the accounts receivable financing program. Considering these lower borrowing costs, the termination of the accounts receivable financing program was prudent, reasonable, and in the best interest of customers.[138]

b. Construction Accounts Payables

The OAG recommended an adjustment to subtract construction accounts payable from rate base alleging that these accounts payables represent "cost-free vendor financing."[139] The OAG based its recommendation solely on the fact that the Commission had adopted similar adjustments in other utility base rate proceedings.[140] Prior to proposing this adjustment, the OAG did not examine whether Duke Energy Kentucky's rate base calculation even included Construction Work in Process (CWIP), which it did not, as explained in the rebuttal testimony of Company witness Lisa D. Steinkuhl.[141] Given that CWIP is not included in rate base, the OAG's recommended adjustment is not appropriate.

Further, during the hearing Company witness Ms. Steinkuhl explained that the Company includes vendor payables in its Allowance for Funds Used During Construction (AFUDC) when those accounts are paid such that there is no delay between vendor payment and when these amounts are accounted for in AFUDC.[142] Since there is no delay

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[137] Heath Rebuttal at 10. Notably, the requested revenue requirement in this case reflects the weighted average cost of debt for the forecast period, which does not include any costs related to the CRC accounts receivable financing program.
[138] *Id.* at 10-11.
[139] Kollen Direct at 10-12.
[140] *Id.*; Steinkuhl Rebuttal at 5.
[141] Steinkuhl Rebuttal at 6 ("The Company disagrees with this adjustment because CWIP is note included in rate base in this proceeding.").
[142] Steinkuhl Cross, HVR at 1:35 (May 22, 2025).

between the vendor payment and accounting for these accounts payable in AFUDC, there is no "zero-cost" financing as alleged by the OAG and no reason to make any adjustment to rate base.[143]

c. Deferred Rate Case Expense

In this case, the Company is proposing to include $1.231 million of deferred rate case expenses in rate base. OAG witness Mr. Futral recommends that the Commission allocate the return on the regulatory asset for the deferred rate case expenses to Duke Energy and its shareholders, but allocate the amortization expense to the Company's customers as a form of sharing between Duke Energy's shareholders and the Company's customers.[144] The effect of this recommendation is a reduction of $0.092 million in the Company's requested revenue requirement increase.[145] Mr. Futral claims that these rate case expenses were and will be incurred to benefit the Company's parent company, Duke Energy, and its shareholders rather than the Company's customers and that this recommendation is necessary to ensure that the costs are equitably shared between Duke Energy shareholders and the Company's customers.[146] Mr. Futral's argument is misguided.

The deferred rate case expenses that the Company seeks to include in rate base represent costs incurred by the Company as part of its cost of service in providing safe and reliable service to its customers.[147] As a regulated utility, the Company must file rate cases, such as the current proceeding, to modify its cost of service and tariffs.[148] As explained by

[143] During the hearing, OAG witness Mr. Kollen appeared to agree that no adjustment was warranted. Kollen Cross, HVR at 2:51-2:52 (May 22, 2025) ("I heard testimony for the very first time today from I think it was from Ms. Steinkuhl that she said the AFUDC calculation reflects that lag. If so, that is fair enough.")
[144] Futral Direct at 12.
[145] *Id.* at 13.
[146] *Id.* at 10–11.
[147] Sarah E. Lawler Rebuttal Testimony at 2 (Lawler Rebuttal) (Apr. 9, 2024).
[148] *Id.*

Company witness Sarah E. Lawler, rate cases are a necessary cost of operating as a public utility, similar to any other costs included in the cost of service.[149] Rate case expenses represent cash outlays by the Company that the Company must finance just like any other deferred expense until revenues are received from its customers to recover these costs.[150] Therefore, it is appropriate to include these regulatory assets in rate base so that the Company is made whole for the time value of money associated with these cash outlays and investors can earn a reasonable return on their investment.[151] Moreover, rate case expense recovery is amortized over a period of years (typically three to five years), making accounting for the time value of money all the more important.[152]

There is no reason to treat rate case expenses differently than any other regulatory asset that the Company is including in rate base and amortizing over a period of years.[153] In addition, allowing the Company to earn an appropriate return on its investments ensures the financial health of the Company is strong, which ultimately helps keep customer rates from increasing significantly.[154] Accordingly, the Commission should reject the OAG's recommendation and approve the Company's proposal to include deferred rate case expenses in rate base.

d. Corporate Alternative Minimum Tax Deferred Tax Asset

The Company included $11.721 million in Corporate Alternative Minimum Tax (CAMT) Deferred Tax Asset (DTA) in rate base, which is Duke Energy Kentucky's allocated portion of Duke Energy Corp.'s forecasted consolidated tax return CAMT DTA

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[149] *Id.*
[150] *Id.*
[151] *Id.* at 2–3.
[152] *Id.* at 3.
[153] *Id.*
[154] *Id.*

for the test year. The CAMT was added to the tax code with the Inflation Reduction Act (IRA) of 2022 and applies to all corporations that have an average adjusted financial statement income (AFSI) of greater than $1 billion over a three-year period.[155] The Internal Revenue Code requires that, for purposes of determining whether the $1 billion threshold of the CAMT is met, the corporation must include the income of all subsidiaries of which it owns at least an 80 percent share.[156] If a corporation meets this $1 billion threshold criteria, the corporation is required to calculate a minimum tax liability that is equal to 15 percent of the corporation's AFSI. The CAMT is compared to the corporation's regular income tax expense and if it is greater, the corporation must pay the CAMT and defer the excess over the regular income tax as CAMT DTA. However, if there is a CAMT DTA carryforward from prior tax years, then the taxpayer can use the CAMT carryforward to reduce its regular income tax to the amount of the CAMT in that tax year, which reduces the CAMT DTA that is carried forward to future years.[157]

The OAG recommended that the Commission exclude the CAMT DTA from rate base because of several prior Commission decisions that required federal income tax liability to be calculated on a standalone basis.[158] However, each of the decisions cited by the OAG were prior to the passage of the IRA and do not address the issue of CAMT DTA.[159] In addition, the Commission recently approved a settlement agreement in another rate case that included CAMT DTA in a utility's rate base.[160]

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[155] Panizza Cross, HVR at 5:35 (May 21, 2025).
[156] Panizza Cross, HVR at 5:35 (May 21, 2025).
[157] Kollen Direct at 23-24.
[158] *Id*. at 25
[159] OAG's Response to Duke Energy Kentucky's First Request for Information, Item 18 (Filed Apr. 2, 2025);
[160] Case No. 2023-00159, *Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) a Securitization Financing Order; and (5) all other Required Approvals and Relief,* Order at 25 (Ky. PSC Jan. 19, 2024).

Inclusion of CAMT DTA in rate base is reasonable given that Duke Energy Corp. is required by the Internal Revenue Code to file a consolidated federal tax return that includes Duke Energy Kentucky.[161] As explained by Company witness John R. Panizza, Duke Energy Corp. is required to file a consolidated tax return for all of its regulated subsidiaries, including Duke Energy Kentucky, because Duke Energy Corp. owns 80 percent or more of each of these subsidiaries.[162] As such it would be inappropriate to calculate the federal income tax expense for Duke Energy Kentucky on a standalone basis since Duke Energy Kentucky is prohibited under the Internal Revenue Code from filing a standalone federal income tax return.

Furthermore, there are customer benefits that arise from the fact the Duke Energy Corp. files a consolidated tax return for all of its regulated entities. For example, if one of the subsidiaries of the consolidated federal tax group is in a net operating loss (NOL) position, other subsidiaries can use those NOL DTAs to reduce rate base and their revenue requirement immediately, rather than wait until that subsidiary has their own income sufficient to utilize the NOL DTA.[163] While the CAMT represents a tax expense that flows from being part of a larger consolidated tax group, it would be one-sided for Duke Energy Kentucky's customers to receive the benefits associated with being part of a consolidated tax group but not also share in the costs.[164] The Commission should therefore reject the OAG's recommendation related to CAMT DTA and accept the Company's proposed CAMT DTA included in rate base for the test year.

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[161] Panizza Cross, HVR at 5:36 (May 21, 2025); *see* 26 CFR § 1.1502-75.
[162] Panizza Cross, HVR at 5:43 (May 21, 2025).
[163] John R. Panizza Rebuttal Testimony at 4 (Panizza Rebuttal) (Apr. 9, 2025); Panizza Cross, HVR at 5:45 (May 21, 2025).
[164] Panizza Rebuttal at 4

3. Operating Income and Deferrals

a. Billed versus Unbilled Revenues

To calculate the overall revenue requirement, the Company used billed revenues to determine current revenues and the resulting revenue deficiency. The OAG recommended that the Company instead rely on unbilled revenue to calculate current revenues.[165] The OAG's recommendation should not be adopted as reliance on unbilled revenues is less accurate and is contrary to decades of established practice for determining revenues.

As discussed by Company witness Ms. Lawler, calculating the revenue requirement based on billed revenues is the most precise and accurate measurement of total revenues. Billed revenues are the total amount that is billed to customers during a given period.[166] In contrast, unbilled revenues is an accounting mechanism to report electricity that has been delivered to customers but has not yet been billed as of the end of the month or other reporting period. Unbilled revenues are used to enable a utility operating under accrual accounting to match revenues with the period in which they are earned rather than when payment is received from customers. In other words, unbilled revenues are simply a non-cash accounting adjustment to accrue revenues earned but not yet billed that gets reversed and re-established on a monthly basis.[167] As a result, billed revenues are a more accurate measure of revenues since they correlate more directly with actual revenues.

Not only is reliance on billed revenue more accurate and less burdensome but Duke Energy Kentucky has also been using this same method for computing rates in "all of the Company's electric and natural gas rate cases for as far back as the Company has

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[165] Kollen Direct at 26.
[166] Lawler Rebuttal at 3.
[167] Lawler Rebuttal at 3-4.

records."[168] This is the first time that the OAG has recommended changing from billed revenues to unbilled revenues.[169] The reason for the OAG's abrupt shift to unbilled revenue appears to be the fact that in this one instance, use of unbilled revenues would result in a reduction to the Company's revenue requirement.[170] This is not sufficient justification to reverse decades worth of practice especially when the existing practice produces a more accurate calculation of revenues. The OAG's recommendation to use unbilled versus billed revenues should be rejected.

b. Forced Outage Replacement Purchased Power Deferral Mechanism

The Company requests approval to reimplement its previously authorized deferral for the actual cost for purchased power expense related to forced outages above or below the amounts being recovered through the Company's Fuel Adjustment Clause (FAC) or in base rates as established in this case.[171] The Commission first approved this process as part of the Company's 2017 electric base rate case.[172] The Company explained that because of the Company's size, and the fact that its load is served primarily by two generating assets, including a single 600 MW coal unit, replacement purchase power costs for forced outages have a significant impact on the Company's financial stability and performance.[173] As part of its decision in the Company's last electric base rate case, Case No. 2022-00372, the

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[168] *Id.* at 4.
[169] *Id.*
[170] *Id.*; Kollen Direct at 28.
[171] John D. Swez Direct Testimony at 31-32 (Swez Direct) (Dec. 2, 2024).
[172] *Id.* at 32 (citing Case No. 2017-00321, *Electronic Application for Duke Energy Kentucky, Inc., for (1) An Adjustment of 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*, Order at 19-20 (Ky. PSC Apr. 13, 2018)).
[173] Swez Direct at 32.

Commission eliminated this deferral finding that the anticipated expense was in line with base rate amounts.[174]

In this case, forced outage purchased power costs have been normalized based upon three years of actual purchased power for forced outages.[175] Company witness Ms. Lawler's direct testimony provided a table, reproduced below as Table 2, that shows the three-year historical average of forced outage purchased power not recovered in the FAC and depicts the volatility of these costs.[176]

Table 2. Three-Year Average of Forced Outage Purchased Power Costs

Line No.	Description	2023	2022	2021	Average
1	Cost of Purchased Power due to Forced Outage	4,537,208	10,932,275	8,264,605	7,911,363
2	Cost of Purchased Power Recovered Through FAC	4,537,208	3,710,050	4,674,065	4,307,108
3	Cost of Purchased Power Deferred in Reg Asset	0	7,222,225	3,590,540	3,604,255

As explained by Ms. Lawler, the variability from year to year in these expenses causes volatility in the Company's earnings.[177] The proposed deferral is designed to, over time, approach $0 and prevent this volatile cost item from having significant influence on the Company's earnings.[178] The costs for which the Company is seeking to create the regulatory deferral represent incremental costs or savings compared to normalized levels, and as such they effectively constitute extraordinary non-recurring expenses (or savings) that could not have reasonably been anticipated or included in the utility's planning.[179] This is especially true for forced outages, which by definition are not pre-planned.[180]

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[174] *Id.*; Case No. 2022-00372, *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*, Order at18 (Ky. PSC Oct. 12, 2023).
[175] Lawler Direct at 10; Swez Direct at 32.
[176] Lawler Direct at 12.
[177] *Id.*
[178] *Id.*; *see also* Danielle L. Weatherston Direct Testimony at 6 (Weatherston Direct), (Dec. 2, 2024).
[179] Lawler Direct at 11.
[180] *Id.*; *see also* Swez Direct at 34 ("At the same time forced plant outages are unpredictable and can expose customers to day-to-day power price volatility for multiple days at a time.").

OAG witness Mr. Kollen recommends that the Commission reject the Company's request to reinstate this deferral mechanism, arguing that "[t]he deferral mechanisms removed all incentives for the Company to manage and control these expenses."[181] However, the record does not support Mr. Kollen's contention. Company witness John D. Swez explained that the Company uses its best efforts to avoid forced outages and derates.[182] The Company does this by addressing maintenance issues proactively as a scheduled outage or, if necessary, a scheduled derate.[183] Scheduling a repair as opposed to waiting until failure for a known operational issue at a generating station tends to result in less damage to equipment, a shorter return time, and potentially less expensive repairs.[184]

In addition, once the generation dispatch group has knowledge of a potential event, personnel work to try and minimize replacement purchase power costs to customers by performing a variety of potential actions, including discussions with the generating station regarding: (1) attempting to repair the unit with a maintenance outage or derate before the issue becomes a forced event; (2) optimizing the placement of an event needed to address an issue, to the extent possible, so that it occurs during a lower demand and lower market price period; (3) optimizing the need to spend additional costs to return a unit to service quicker; and (4) discussion of the likelihood of capacity performance charges so that stations are situationally aware and can proactively work to reduce operational risks by delaying non-critical maintenance or testing.[185] These actions attempt to reduce the

[181] Kollen Direct at 53–54.
[182] John D. Swez Rebuttal Testimony at 2 (Swez Rebuttal) (Apr. 9, 2025).
[183] *Id.*
[184] *Id.*
[185] *Id.* at 3.

replacement power cost of the forced event and increase the value of the Company's generating units in the energy market.[186]

Company witness Mr. Swez also testified that at no point does the generation dispatch group consider the relationship between how costs are recovered or the allocation of any costs between customers and shareholders when managing forced events.[187] The Company manages any outage event, forced or otherwise, to reliably serve customers in the most economic manner possible and maintain the safe and reliable operation of the generating units.[188] The Company's response and actions described above are completed without regard to any after-the-fact accounting process.[189]

Notably, Mr. Kollen's testimony does not address the reasonableness of reinstituting the forced outage replacement purchased power deferral. Indeed, he provides no basis for his recommendation to deny the Company's proposed deferral other than his claim that the deferral mechanism removed incentives for the Company to manage and control these expenses which the Company has clearly refuted.

Reinstatement of the forced outage deferral is reasonable, necessary, and in customers' best interests. As explained by Company witness Mr. Swez, although the Company works to reduce the financial exposure to forced events to the extent possible, these events are unpredictable and replacement power costs can be volatile.[190] Since Duke Energy Kentucky is relatively small and only has two fossil-fueled generating stations, one coal unit and a natural gas combustion turbine station, replacement purchased power is the

[186] *Id.*
[187] *Id.* at 4.
[188] *Id.*
[189] *Id.*
[190] *Id.*; *see also* Lawler Direct at 12.

Company's primary mechanism for serving customer demand if either generating station is in a forced event and can have a greater impact on customer rates.[191] The deferral balances the need for protecting customers from overpaying for these costs when the utility's actual costs incurred are below the levels used to establish base rates and conversely mitigates the utility's risk of financial harm and instability and performance during periods where the Company's actual costs incurred are higher than amounts included in base rates.[192] Reinstituting this deferral process ensures that the Company is able to maintain financial stability to reliably serve customers' demand and that customers are paying for their actual costs of service.[193] The Company's request to reinstate this deferral mechanism is reasonable and should be approved.

c. Planned Generation Outage O&M Deferral Mechanism

The Company is also seeking to reimplement its previously authorized deferral for planned outage O&M expense of its generation fleet above or below the baseline amount being recovered in base rates.[194] The Commission first approved this deferral as part of the Company's 2017 electric base rate case.[195] The Company explained that because of the Company's size, and the fact that its load is served primarily by two generating assets, including a single 600 MW coal unit, planned maintenance outages have a significant impact on the Company's financial stability and performance.[196] As part of its decision in

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[191] Swez Rebuttal at 4.
[192] *Id.* at 4–5; *see also* Weatherston Direct at 5.
[193] Swez Rebuttal, at 5; *see also* Weatherston Direct at 5.
[194] Luke Direct at 24.
[195] *Id.* (citing Case No. 2017-00321, *Electronic Application for Duke Energy Kentucky, Inc., for (1) An Adjustment of 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*, Order at 19-20 (Ky. PSC Apr. 13, 2018)).
[196] Luke Direct at 24–25.

Case No. 2022-00372, the Commission eliminated this deferral, finding that the anticipated expense was in line with base rate amounts.[197]

In this case, the Company's forecasted test year budget for planned outage O&M expense for the Company's East Bend and Woodsdale generating stations have been adjusted to reflect a representative (*i.e.*, average) level of expense.[198] Planned outage O&M expense has been normalized based upon four years of actual O&M expense and four years of projected O&M expenses.[199] The table below, included in Company witness Ms. Lawler's direct testimony, shows the eight-year average of planned outage O&M and depicts the volatility of these costs.[200]

Table 3. 2020-2027 Planned Outage O&M Expense

Year	Description	East Bend	Woodsdale	Total	CPI 2023= 100 (A)	Total
2020	Planned Outage O&M	$ 6,916,095	$ 845,490	$ 7,761,585	84.9%	$ 9,142,032
2021	Planned Outage O&M	10,409,808	638,725	11,048,533	90.9%	12,154,602
2022	Planned Outage O&M	7,960,822	464,577	8,425,399	96.8%	8,703,925
2023	Planned Outage O&M	11,408,243	716,017	12,124,260	100.0%	12,124,260
2024	Planned Outage O&M	4,122,034	462,340	4,584,374	100.0%	4,584,374
2025	Planned Outage O&M	8,228,256	2,685,000	10,913,256	100.0%	10,913,256
2026	Planned Outage O&M	8,191,270	4,570,000	12,761,270	100.0%	12,761,270
2027	Planned Outage O&M	1,262,177	2,420,000	3,682,177	100.0%	3,682,177
	8 Year Average			$ 8,912,607		$ 9,258,237

As explained by Ms. Lawler, the variability from year to year in these expenses causes volatility in the Company's earnings.[201] The deferral is designed to, over time, approach $0 and prevent this volatile cost item from having significant influence on the Company's

[197] *Id.* at 25 (citing Case No. 2022-00372, *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*, Order at18 (Ky. PSC Oct. 12, 2023)).
[198] *Id.*
[199] Lawler Direct at 10; Luke Direct at 25.
[200] Lawler Direct at 12.
[201] *Id.*

earnings.[202] The costs for which the Company is seeking to create the regulatory deferral represent incremental costs or savings compared to normalized levels, and as such they effectively constitute extraordinary non-recurring expenses (or savings) that could not have reasonably been anticipated or included in the utility's planning.[203]

OAG witness Mr. Kollen recommends that the Commission reject the Company's request to reinstate this deferral mechanism, arguing that "[t]he deferral mechanisms removed all incentives for the Company to manage and control these expenses."[204] As an initial matter, it should be noted that Mr. Kollen does not address in his testimony the reasonableness of reinstituting the deferral mechanism for planned outage O&M expense. Mr. Kollen also does not address whether the conditions for which the Commission's decision to eliminate this deferral in the prior base rate case still exist. Mr. Kollen provides no basis for his recommendation to deny the Company's proposal to reestablish the deferral of planned outage O&M expense other than his claim that the deferral mechanism removed incentives for the Company to manage and control these expenses.

Mr. Kollen's claim is incorrect. Company witness William C. Luke explained that at no point do the generating stations consider how costs are recovered nor the allocation of any costs between customers and shareholders when determining the planned maintenance activities required to maintain the safe, reliable, and efficient operation of their generating assets.[205] Rather, maintenance activities are planned and executed based on several factors including the operating profile of the equipment, online monitoring, offline condition inspections, fleet operating experience, and original equipment

[202] *Id.*; *see also* Weatherston Direct at 6.
[203] Lawler Direct at 11.
[204] Kollen Direct at 53–54.
[205] William C. Luke Rebuttal Testimony at 2 (Luke Rebuttal) (Apr. 9, 2025).

manufacturers recommendations.[206] The planned maintenance activities are completed without regard to any after-the-fact accounting process.[207]

Additionally, as explained by Mr. Luke, it is in the Company's interest to manage and control these expenses as the Company is required to demonstrate prudency of expenses incurred in rate case reviews.[208] The Company controls costs through a rigorous cost management program, involving routine executive oversight of budget and activity reporting, with projects requiring approval by progressively higher levels of management depending on total cost.[209] The Company uses strategic planning and procurement, efficient oversight of contractors by a trained and experienced workforce, rigorous monitoring of work quality, thorough critiques to drive process improvement, and industry benchmarking to ensure the use of best practices.[210] In sum, the Company runs its generating fleet in a disciplined manner and continuously balances cost management with safety and reliability to generate electric service for its customers.[211]

Reinstatement of the planned outage O&M deferral is reasonable, necessary, and in customers' best interests. Mr. Luke testified that periodically, generating assets require larger maintenance scopes to be executed due to the normal lifecycle wear of larger components or systems, and these periods of large scope activities drive significant year-over-year variations in maintenance costs for the Company.[212] Therefore, the year-over-year maintenance expense will also vary significantly from the normalized eight-year

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[206] *Id.*
[207] *Id.* at 2–3.
[208] *Id.* at 3.
[209] *Id.*
[210] *Id.*
[211] *Id.*
[212] *Id.* at 3–4.

average planned outage O&M expense.[213] Duke Energy Kentucky is also relatively small and only has two fossil-fueled generating stations, limiting the Company's ability to control these variations.[214] Reinstituting the deferral for planned outage O&M expense helps to prevent volatile swings in the Company's cash flows, which directly impacts the Company's financial stability.[215]

In addition, as described above, the Company budgets its planned outage O&M expense to ensure reliable, cost-effective generation for customers.[216] The proposed deferral balances the need for protecting customers from overpaying for these costs when the utility's actual costs incurred are below the levels used to establish base rates and conversely mitigate the utility's risk of financial harm and instability and performance during periods where the Company's actual costs incurred are higher than amounts included in base rates.[217] The Company's request to reinstate this deferral mechanism is reasonable and should be approved.

d. Decommissioning Expense as a Component of Depreciation

The Company is proposing to include terminal net salvage (*i.e.*, decommissioning costs) in its depreciation rates, as has been its practice for decades. OAG witness Mr. Kollen has three primary objections to the development of terminal net salvage estimates in this case. First, Mr. Kollen claims that decommissioning costs should be excluded from the depreciation rate calculation not only for the East Bend and Woodsdale generating units, but also for the solar generating units.[218] Second, and alternatively, Mr. Kollen states

[213] *Id.* at 4.
[214] *Id.*
[215] *Id.*
[216] *Id.*
[217] *Id.*; *see also* Weatherston Direct at 5.
[218] Kollen Direct at 42.

that if generating unit decommissioning expense is allowed, then it should be as a standalone expense, and Mr. Kollen asserts that the escalation of decommissioning costs to the date of retirement should be reduced to just the test year.[219] Third, Mr. Kollen recommends that estimated end-of-life materials and supplies be removed from the decommissioning cost estimate and should only be recovered after unit retirement.[220] None of these recommendations are reasonable, and Mr. Kollen provides no evidence to support their merit.

In the Company's depreciation studies prior to the 2022 Rate Case, the terminal net salvage estimates included escalation to the date of retirement and were developed in the same manner as in the instant case.[221] The Commission approved the Company's proposals with regard to terminal net salvage:

> The Commission finds Duke Kentucky's recommendation on the treatment of terminal net salvage value in the computing the depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved.[222]

It is widely accepted that depreciation should include future net salvage costs, which are recovered on a straight-line basis, and that those costs should be based on the expected cost to retire the Company's assets at the time of retirement or removal.[223] This applies not only to decommissioning costs, but also to the costs of all plant assets.[224] Because net salvage must be based on future costs, decommissioning costs for net salvage

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[219] *Id.* at 42–43.
[220] *Id.* at 43.
[221] John J. Spanos Rebuttal Testimony at 6 (Spanos Rebuttal), (Apr. 9, 2025).
[222] *Id.* (citing Case No. 2017-00321, *Electronic Application for Duke Energy Kentucky, Inc., for (1) An Adjustment of 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*, Order at27 (Ky. PSC Apr. 13, 2018)).
[223] Spanos Rebuttal at 7.
[224] *Id.*

must also be estimates of the future cost at the time of decommissioning.[225] For this reason, if decommissioning estimates are developed using the cost to decommission a plant today, then these costs must be escalated to the time period in which they are expected to be incurred to achieve adequate recovery.[226] When using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts each year, over the life of the Company's plant.[227]

Recovering the future cost of net salvage is consistent with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA). As explained by Company witness John J. Spanos, the FERC USOA specifically defines net salvage as follows:

> 19. Net salvage value means the salvage value of property retired less the cost of removal. (Emphasis added).

Cost of removal is defined as:

> 10. Cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation, and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (*See* General Instruction 25).

Finally, cost is defined as:

> 9. Cost means the amount of money actually paid for property or services. When the consideration given is other than cash in a purchase and sale transaction, as distinguished from a transaction involving the issuance of common stock in a merger or a pooling of interest, the value of such consideration shall be determined on a cash basis.[228] (Emphasis added).

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[225] *Id.* at 8.
[226] *Id.*
[227] *Id.*
[228] *Id.* at 8–9.

The concept that net salvage costs need to be escalated so that the correct amounts are allocated over the lives of the plants is supported by authoritative guidance, namely two preeminent depreciation texts, the National Association of Regulatory Utility Commissioners' *Public Utility Depreciation Practices* (NARUC Manual) and *Depreciation Systems* by Wolf and Fitch (Wolf and Fitch).[229] Both texts are clear that net salvage should be included in depreciation as a future cost. The NARUC Manual states the following:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between the gross salvage that will be realized <u>when the asset is disposed of and the cost of retiring it</u>.[230] (Emphasis added).

The NARUC Manual also explains that:

> The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, <u>making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired</u>. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, <u>if current users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized</u>.[231] (Emphasis added).

Similarly, Wolf and Fitch explain that:

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses.[232]

Clearly, the terminal net salvage should be included in the depreciation rate.

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[229] *Id.* at 9–10.
[230] *Id.* at 10 (citing NARUC Manual at 18).
[231] Spanos Rebuttal, at 10 (citing NARUC Manual at 18).
[232] Spanos Rebuttal, at 10 (citing Wolf and Fitch at 7).

Second, it is both expected and appropriate that decommissioning costs will increase if the original cost increases. The development of the weighted net salvage includes both interim and terminal net salvage, which is based on the plant in service forecasted to be in place up to the date of retirement.[233] Therefore, the amount that is equitably included in the depreciation rate is determined based on both the interim survivor curve and the decommissioning cost as a percentage of the assets in service each year up to the date of retirement. Mr. Kollen's proposal to segregate the decommissioning expense and base it on a calculation performed at a single point in time (in this case, December 31, 2023) would significantly underestimate the full cost of decommissioning at the end of the facility's life. Not only does Mr. Kollen's proposed method of segregating decommissioning from the calculation of depreciation deviate from industry practice, but it can also lead to a departure from the matching principle that is a fundamental depreciation concept.[234]

Furthermore, the Company has a concern with Mr. Kollen's recommendation regarding the additional administrative burden that will have to be incurred to administer the proposal. The Company's Power Plan system is not designed to calculate two separate depreciation rates—one for the core asset and one for decommissioning. Mr. Kollen's recommendation would require creation of a manual entry each month with no benefit. Moreover, since the Company has not tracked depreciation rates and depreciation expense separately up to this point, there is no accurate way to segregate what has been expensed and accrued to date between core asset depreciation and decommissioning expense. Additionally, this would be a deviation in practice from how the Company calculates

[233] Spanos Rebuttal, at 11.
[234] *Id.*

depreciation expense and cost of removal for all other asset types—distribution and transmission.

It is also reasonable to include estimated end-of-life materials and supplies as part of decommissioning costs recovered through depreciation expense. Disposing of remaining inventory is just as much a part of decommissioning a station as disposing of other equipment and plant components.[235] In fact, the warehouse, or other portions of the plant where the supplies are held, cannot be demolished until the inventory is safely removed.[236] Moreover, when the plant is retired, the value of this inventory is reduced to the value it has as salvage or scrap.[237] This reduction in value of the inventory is a cost associated with net salvage rates associated with retirement and demolition of the facility.[238] Given all of these issues and concerns with Mr. Kollen's proposal and the lack of any real benefit, the Commission should reject this recommendation and approve the depreciation rates that the Company has proposed.

Lastly, Mr. Kollen argues that KRS 278.264 precludes the Company from requesting, and the Commission from considering, the recovery of decommissioning costs unless the utility is actually seeking to retire a thermal generating unit in a proceeding initiated for that specific purpose.[239] In the Company's last base rate proceeding, Case No. 2022-00372, the Commission raised the issue of the rebuttable presumption under KRS 278.264 as it relates to the ability to continue recovering terminal net salvage expense in base rates.[240] The Commission found that "terminal net salvage should be removed from

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[235] *Id.* at 13.
[236] *Id.*
[237] *Id.*
[238] *Id.*
[239] Kollen Direct at 39.
[240] Lawler Rebuttal at 7.

the depreciation rates due to the requirements of KRS 278.264(2) that the Commission 'shall not . . . take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit . . . unless the presumption created by this section is rebutted.'"[241] However, with regard to the Company's solar assets, the Commission ultimately held the solar assets are not governed by KRS 278.264 and authorized decommission expenses for these solar assets to remain in depreciation rates.[242]

As it relates to East Bend and Woodsdale, contrary to Mr. Kollen's argument, the statute does not expressly state that an actual unit retirement is a precursor to receiving recovery of costs.[243] It merely makes satisfying the rebuttable presumption a requirement to achieve the cost recovery.[244] Indeed, the Commission's Order on Rehearing in Case No 2022-00372 explicitly stated that the Company was not prohibited from requesting depreciation rates for its fossil generation in a future proceeding based on new information or environmental regulations in accordance with KRS 278.264, and affirmed the basis of its decision was that the Company had not addressed the rebuttable presumption in that case.[245] In this case, the Company has addressed the prior evidentiary deficiency, and the presumption created by KRS 278.264 has been rebutted by the Company. Therefore it is within the Commission's authority to grant the Company's request to include decommissioning costs in rates today.

As explained by Company witness Ms. Lawler, KRS 278.264 creates a threshold of criteria that the utility must demonstrate before it can retire a generating asset that is

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241 Lawler Direct at 5–6.
242 Lawler Rebuttal at 10.
243 *Id.* at 8.
244 *Id.*
245 Case No. 2022-00372, *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*, Order at 8 and 11 (Nov. 21, 2023).

fueled by fossil fuel.[246] It provides, in relevant part, that in order to retire a generating unit, receive a surcharge for decommissioning of a unit, or be authorized recovery of any retirement costs, including stranded asset recovery, the utility must demonstrate, and the Commission must find, the following:

> (a) The utility will replace the retired electric generating unit with new electric generating capacity that:
>
> > 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
> > 2. Maintains or improves the reliability and resilience of the electric transmission grid;
> > 3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator; and
> > 4. Has the same or higher capacity value and net capability, unless the utility can demonstrate that such capacity value and net capability is not necessary to provide reliable service;
>
> (b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law;
> (c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency; and
> (d) The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier.[247]

Company witnesses Messrs. Luke, Swez, and Matthew Kalemba explain in their testimony that the Company will replace East Bend and Woodsdale with generation that will be dispatchable by PJM Interconnection LLC (PJM) and will at a minimum maintain the reliability and resilience of the electric transmission grid.[248] They further explain that

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[246] Lawler Direct at 6.
[247] *Id.* at 5-6 (quoting KRS 278.264).
[248] Luke Direct at 17; Swez Direct at 4; Matthew Kalemba Direct Testimony at 8 (Kalemba Direct) (Dec. 2, 2024).

any replacement will maintain necessary reserve capacity requirements established by PJM and will have the same or higher capacity value of East Bend and Woodsdale currently.[249] Messrs. Luke and Kalemba also explain that the decision to retire is not based on any financial incentives or benefits offered by any federal agency.[250] Ms. Lawler explains that the inclusion of terminal net salvage costs in depreciation expense will not result in any net *incremental* costs that could be avoided by continuing to operate East Bend and Woodsdale.[251] There are no incremental costs to be incurred.[252] The costs to decommission these plants exists, and including these costs in depreciation rates today does not result in incremental net costs to the customer.[253] Additionally, as Mr. Kalemba explains, the Company's IRP demonstrates the Company's approach to retire East Bend is the least cost to customers.[254] Finally, Luke and Kalemba also explain that the Company will not commence retirement or decommissioning of East Bend or Woodsdale before the replacement generation capacity meeting the requirements of KRS 278.264 is fully constructed, permitted, and in operation.[255] Mr. Kollen does not proffer any evidence that the Company's justification or explanation was in anyway deficient or insufficient. Thus, the Commission has the authority within the law and should reauthorize the recovery of terminal net salvage expense through depreciation rates.

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[249] *Id*.
[250] *Id*.
[251] Lawler Direct at 7.
[252] *Id.*
[253] *Id.*
[254] Kalemba Direct at 9.
[255] *Id*. at 15; Luke Direct at 14.

e. Aligning Depreciation Expense with East Bend's Useful Life

The Company is proposing to align the depreciable life of East Bend with the estimated useful life of the asset.[256] Based on the Company's 2024 IRP, the Company currently estimates East Bend to retire as of December 31, 2038.[257] OAG witness Mr. Kollen recommends that the Commission reject the Company's request and maintain East Bend's depreciable life through 2041.[258] Mr. Kollen's recommendation results in a decrease in depreciation expense of $5.373 million and a decrease in accumulated depreciation, net of ADIT effects, of $1.347 million.[259] This results in a corresponding revenue impact of $5.272 million.[260] This is comprised of a reduction of $5.406 million for the decrease in depreciation expense and an increase of $0.134 million for the decrease in accumulated depreciation net of ADIT impacts.[261]

The Company disagrees with Mr. Kollen's proposal and believes that the depreciable life through December 31, 2038, is the most appropriate date to include in this proceeding. First, the purpose of a probable retirement date and the impact on depreciation is to estimate the life cycle of each asset class and to recover the investment over the same time period that the asset will render service.[262] Mr. Kollen chose to ignore this proposal by suggesting that "the recovery of the remaining net book value of East Bend 2 in 2038 should be considered a cost of transitioning to the new capacity and recovered, at least in part, from the generation of customers that will be served by the new capacity."[263] He

[256] Lawler Direct at 4.
[257] *Id.*
[258] Kollen Direct at 36.
[259] Steinkuhl Rebuttal at 13.
[260] *Id.*
[261] *Id.*
[262] Spanos Rebuttal at 2.
[263] Kollen Direct at 36.

reasons that "future customers should bear the remaining cost of the East Bend 2 in exchange for the benefits they will achieve from an earlier transition to lower cost replacement capacity."[264] Not only is this an arbitrary proposal, but more importantly, it is at odds with a fundamental concept of depreciation, which is matching recovery to the usage of assets.[265] The matching principle is based on the concept that customers that benefit from the service pay for the service equally over the life of the asset systematically and rationally.[266]

Additionally, Mr. Kollen provides no basis for his proposal of a December 31, 2041 estimated retirement date, aside from it being the previously estimated date for this facility. In contrast, the Company's proposed December 31, 2038 retirement date is supported by the Company's informed judgment of East Bend based on evaluation of various economic considerations. The Company has clearly identified that December 31, 2041 is no longer a realistic expectation for the life span of this facility as expressed by other Company witnesses in this case. In fact, this date was estimated over 40 years ago when the asset was first placed in service. Now, as the asset is nearing its end of useful life, the Company can more accurately estimate its end of life. Company witness Mr. Luke explained that the Company is anticipating that East Bend will retire no later than December 31, 2038, as a result of its age, economics, and environmental regulations, that at the time of the filing of the Company's Application, included the United States Environmental Protection Agency's (US EPA) Clean Air Act 111 Update (CAA 111 Update) that limits the operation of existing coal-fired generation.[267] Additionally, there are multiple drivers for this

[264] *Id.*
[265] Spanos Rebuttal at 2.
[266] *Id.* at 3.
[267] Luke Direct at 11.

anticipated retirement that could also accelerate the retirement without the CAA 111 Update, most significantly, market pressures that are negatively impacting the long-term viability of coal-fired generation.[268]

Furthermore, as explained by Company witness Mr. Kalemba, the Company's most recent IRP, filed with the Commission in Case No. 2024-00197, analyzed several scenarios that could impact the Company's resource portfolio.[269] These scenarios drove the development of portfolio possibilities, with the most likely result being East Bend's conversion to dual fuel operation by adding natural gas co-firing capability by 2030.[270] This would allow the unit to continue operating as both a coal-fired unit and a natural gas unit through the end of 2038, the time limit established by the CAA 111 Update for coal-conversions.[271] In addition, under a no-CAA 111 Update scenario in the 2024 IRP, East Bend actually retires earlier, by December 31, 2035, due to economics, reliability concerns, and other risks.[272] In either event, the unit retires earlier than the current December 31, 2041, depreciable life date approved by the Commission in the Company's last electric rate case.[273]

Moreover, in recent years, there is clearly a trend of increased coal generation retirement, and most, if not all, of the retired facilities are being taken out of service earlier than their estimated retirement dates.[274] Since 2015, the average age of coal fired generating facilities has been well below 50 years.[275] East Bend will have a life span of 57

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[268] *Id.*
[269] Kalemba Direct at 4–7.
[270] Luke Direct at 12.
[271] *Id.*
[272] Kalemba Direct at 10.
[273] *Id.*
[274] Luke Direct at 4.
[275] *Id.*

years if retired in 2038.[276] For these reasons, the Commission should approve the Company's proposal to align the depreciable life of East Bend with the estimated useful life of the asset of December 31, 2038.

f. Directors and Officers Insurance, Board of Directors' Compensation, and Investor Relations Expense

The OAG recommends that the Company's Directors and Officers (D&O) insurance, Board of Directors' compensation, and investor relations expenses each be reduced by 50 percent such that these expenses are shared 50/50 between ratepayers and customers.[277] The Commission should reject the OAG's proposed adjustments as these expenses are prudent and necessary to provide electric service to customers, the OAG has failed to provide any analysis demonstrating the reasonableness of its proposed adjustment, the adjustments are arbitrary and inconsistent with prior Commission decisions.

Under Kentucky law, utilities are entitled to "demand, collect, and receive fair, just and reasonable rates for the services rendered or to be rendered…"[278] Each of the proposed expenses that the OAG recommends be reduced are legitimate, and in some cases statutorily required, expenses incurred to support the utility's ability to provide safe and reliable service to its customers and should be allowed to be recovered in full. For instance, D&O insurance is designed to protect the Company, and ultimately ratepayers, from potential costs that could be incurred if its directors and officers are involved in litigation stemming from their work for the utility. This is an important risk management tool that protects the utility's leadership from claims that could disrupt governance of the corporation. Failure to provide this type of insurance could also impair the Company's

[276] *Id.*
[277] Futral Direct at 27-28.
[278] KRS 278.030.

ability to attract qualified officers and directors. D&O insurance also benefits customers by reducing the costs that would be passed on to ratepayers if Duke Energy Kentucky's executives were involved in litigation. This is because, in certain circumstances, corporations are required under Kentucky law to indemnify directors for reasonable expenses incurred during litigation related to their board service.[279]

Likewise, Board of Directors' compensation is a legitimate business expense that also benefits customers. Kentucky law requires that corporations have a board of directors.[280] A skilled and competent board of directors benefits customers by providing strategic leadership and appropriate oversight and management of the corporation.[281]

Investor relations expenses are also necessary business expenses as they help support Duke Energy Kentucky's efforts to communicate with potential investors.[282] Running an electric utility is a capital-intensive business that requires substantial investments in power plants and transmission and distribution facilities. In such a capital-intensive business, a lower cost of debt and equity is essential to being able to provide customers with this necessary infrastructure to support reliable electric service. A lower cost of debt and equity also directly reduces the revenue requirement that customers must support for these investments.[283] As a result, investor relations expenses that enable

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[279] *See, e.g.*, KRS 271B.8-520 ("Unless limited by its articles of incorporation, a corporation shall indemnify a director who was wholly successful, on the merits or otherwise, in the defense of any proceeding to which he was a party because he is or was a director of the corporation against reasonable expenses incurred by him in connection with the proceeding.").

[280] See, e.g., KRS 271B.8-010 ("(1) Except as provided in subsection (3) of this section, each corporation shall have a board of directors. (2) All corporate powers shall be exercised by or under the authority of, and the business and affairs of the corporation managed under the direction of, its board of directors, subject to any limitation set forth in the articles of incorporation. (3) A corporation having fifty (50) or fewer shareholders may dispense with or limit the authority of a board of directors by describing in its articles of incorporation who will perform some or all of the duties of a board of directors.").

[281] Steinkuhl Rebuttal at 9-10.

[282] Steinkuhl Rebuttal at 10.

communication with equity investors is crucial to the Company's ability to fund these investments and provide safe and reliable service to its customers.

Notably, the OAG does not contend that any of these expenses were imprudently incurred or excessive. Rather, the OAG's entire argument is that these expenses benefit shareholders as well as customers and therefore should be shared. This argument is deeply flawed. Yes, all expenses benefit shareholders and customers. As stated above the Kentucky law entitles utilities to demand, collect, and receive fair, just, and reasonable rates for the services rendered, the regulatory ratemaking model used for decades has already been designed to ensure that balance between customers and shareholders. The cost of service model is designed such that the utility calculates its total cost to serve customers incorporating a reasonable ROE to appropriately compensate shareholders/investors. To then exclude certain prudently incurred costs from the cost to serve has the effect of double dipping in the favor of customers and putting the Company in a position that it will never be able to earn its allowed rate of return. This is unnecessary, punitive, unreasonable, and inappropriate. As noted above, each of these expenses are legitimate expenses associated with running an electric utility for the benefit of customers and therefore should be recovered in their entirety. Setting this aside, the OAG also does not provide any analysis for how it determined that a 50/50 sharing of these expenses is an appropriate allocation of these costs. When asked in discovery about how this allocation was developed, the OAG stated that it was based on recent decisions from the Texas Public Utilities Commission and not any analysis of the actual expenses at issue in this case.[284] The OAG also did not cite to any prior decisions from this Commission that supported its position. This is not

[284] OAG's Response to Duke Energy Kentucky's First Request for Information, Item 37 (Filed Apr. 2, 2025); Futral Cross, HVR at 3:53 (May 22, 2025).

surprising as this Commission has previously found that these expenses are legitimate business expenses that should be recovered in full. In approving a recent settlement in Columbia Kentucky's rate case, this Commission explained its rationale for approving D&O insurance costs explaining,

> The Commission agrees with Columbia Kentucky that these expenses are legitimate business expenses that reduce the costs that would be passed on to ratepayers if Columbia Kentucky's executives were involved in litigation related to the operation of the utility. In addition, the Commission agrees with Columbia Kentucky's arguments that this insurance may reduce borrowing costs.[285]

There is no principled basis for requiring shareholders to absorb half of these costs when they support the utility's ability to provide safe and reliable service, access capital markets, and comply with regulatory mandates—all of which serve Kentucky customers. The OAG's proposed adjustment should be rejected.

g. Calculation of Uncollectible Expense

The Company proposes to include $4.152 million in uncollectible expense in its revenue requirement in this proceeding.[286] This amount was calculated by applying the total projected electric revenue subject to the uncollectible expense of $450.814 million by a historical uncollectible expense factor of 0.921 percent, which was computed based on 2023 total company (electric and natural gas divisions combined) uncollectible expense.[287] The Company relied on total company uncollectible amounts in part because the Company

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[285] Case No. 2024-00092, *Electronic Application of Columbia Gas of Kentucky, Inc., for an Adjustment of Rates; Approval of Depreciation Study; Approval of Tariff Revisions; and Other Relief*, Order at 27-29 (Ky. PSC Dec. 30, 2024).
[286] Futral Direct at 17.
[287] *Id.*

did not track separate electric and natural gas amounts in 2023.[288] Separate electric and natural gas uncollectible expenses first became available in 2024.[289]

The OAG recommended reducing the Company's uncollectible expense factor to 0.454 percent which is the 2024 electric-only expense factor.[290] Given that the majority of Duke Energy Kentucky's customers are combination customers that take both electric and natural gas service, it is inappropriate to rely only an electric uncollectible expense factor to determine uncollectible expense in this proceeding.[291] These combination customers receive one bill for their electric and natural gas service. As such, the uncollectible factor should be based on the historical percentage of uncollectible expense for both electric and gas – not electric alone.

Further, as noted in Company witness Ms. Steinkuhl's rebuttal testimony, if the Commission rejects the OAG's recommendation, all of the OAG's recommended adjustments will need to be recalculated using a pre-tax gross up factor of 1.0108811 which includes the uncollectible factor of 0.9210 percent as opposed to the pre-tax gross up factor of 1.0061314 which includes the uncollectible factor of 0.4540percent included in Table 1 of OAG witness Mr. Futral's direct testimony.[292]

h. Fee-Free Card Payment Proposal

In this proceeding, the Company is proposing a new customer program that is designed to alleviate the most frequently expressed payment-related frustration of residential customers: payment fees.[293] Currently, the Company accepts residential

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[288] *Id.*
[289] *Id.* at 18.
[290] Futral Direct at 20.
[291] Steinkuhl Rebuttal at 7.
[292] Steinkuhl Rebuttal at 8.
[293] Jacob S. Colley Direct Testimony at 18 (Colley Direct) (Dec. 2, 2024).

customer payments without fees through check, money order, cash (via some walk-in payment locations), automated bank drafts, and Electronic Funds Transfer.[294] The Company's proposal would expand the available fee-free payment options to include payments by debit, credit, prepaid cards, and electronic check (collectively, Card Payments).[295] In particular, the Company's proposal would eliminate the $1.25 per transaction convenience fee paid by residential customers for each Card Payment.[296] Duke Energy Kentucky would instead pay the $1.25 per transaction fee for Card Payments to the third-party credit card payment processor, Speedpay, and those costs would become part of the Company's cost of service just like the costs associated with any other form of customer payment today.[297]

OAG witness Mr. Kollen recommends the Commission reject the Company's fee-free Card Payment proposal as he believes the elimination of the fees would result in expanded utilization of the payment channel, thus increasing the revenue requirement for those costs in future base rate proceedings.[298] Mr. Kollen further implies the elimination of Card Payment fees would unfairly shift costs to all customers, including those who do not use the card payment channel.[299]

Mr. Kollen's argument above fails to note that if the Card Payment costs were to increase above the expense set in this case, the Company would not be able to recover those costs until this expense amount is reset in the Company's next rate case.[300] Further, to ensure Card Payment fees remain affordable for customers, the Company has negotiated a

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[294] *Id*.
[295] *Id*.
[296] Jacob S. Colley Rebuttal Testimony at 2 (Colley Rebuttal) (Apr. 9, 2025).
[297] *Id.*
[298] *Id*. at 3.
[299] *Id*.
[300] *Id*. at 4.

17 percent reduction in the Card Payment transaction fee from $1.50 to $1.25 for residential payments.[301] This reduction demonstrates the Company's efforts to minimize the cost impacts on all customers.[302]

Mr. Kollen also ignores the fact that elimination of Card Payment fees simply puts this type of payment on the same footing as other payment options offered by the Company. The Company does not charge customers a payment fee for paying by check, money order, or cash even though there are expenses associated with processing these payments. Instead these processing fees are built into the cost of service paid for by all customers.[303] By proposing to eliminate this fee, the Company is simply trying to put this payment option in line with other payment options and consistently include the transaction costs associated with all payment options in the cost of service.

The Commission should approve the fee-free Card Payment proposal as it is a crucial step in providing more inclusive access to payment methods, especially for unbanked and underbanked customers who may rely on prepaid or debit cards.[304] The Company noted that nearly 50 percent of Duke Energy Kentucky's agency recipients used a Card Payment at least once over the past six month to pay their utility bill as compared to 19 percent of non-recipients.[305] In offering these inclusive fee-free payment options to residential customers, the Company is not only addressing a significant customer frustration but also providing all customers, regardless of their financial situation, with

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[301] *Id*.
[302] *Id*.
[303] Colley Rebuttal at 5.
[304] *Id*. at 2-3.
[305] Colley Direct at 19.

access to convenient and fee-free payment options.[306] This also ensures all payment method related costs are treated consistently within the cost of service.

i. PJM NITS Transmission Fees

Duke Energy Kentucky projected $28.795 million in PJM Network Integrated Transmission Service (NITS) fees in the test period.[307] To project the PJM NITS transmission fees for the test year, the Company compared actual expense for the first six months of 2024 with actual PJM NITS fees for the first six months of 2023 to determine a 11.7 percent escalation factor.[308] The Company relied on a partial year for 2024 because at the time the Application was filed, this was the most recent data.[309] This 11.7 percent escalation factor was then applied to 2023 actual PJM NITS fees to project 2024, 2025, and 2026 fees.[310] The Company calculated the PJM NITS fees for the test year ending June 30, 2026 by combining half of the 2025 amount with the 2026 amount.[311]

The OAG recommended that the PJM NITS fees for the test year be set at $26.517 million, or $2.278 million less than the $28.795 million projected by the Company.[312] The OAG calculated this reduced amount by using the full year actuals for 2024, that were not available at the time of the Application, and then escalating that amount by 8.1 percent each year to determine the 2025 and 2026 amounts.[313] The 8.1 percent escalation factor is based on the increase in PJM NITS fees between 2023 and 2024.[314] As noted in rebuttal, while the Company does not dispute the OAG's recommended adjustment, the Company's

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[306] *Id*. at 3.
[307] Claire Hudson Rebuttal Testimony at 5 (Hudson Rebuttal) (Apr. 9, 2025).
[308] Futral Direct at 22.
[309] Hudson Rebuttal at 5.
[310] Futral Direct at 22.
[311] *Id.*
[312] *Id.* at 25.
[313] *Id.*
[314] *Id* at. 24.

method of calculating the escalation of PJM NITS fees was reasonable and appropriate based on the information that was available at the time the Application was filed in this proceeding.[315]

4. Rate of Return

a. Return on Equity (ROE)

In this case, the Company is requesting an authorized ROE of 10.85 percent within a range of 10.25 to 11.25 percent,[316] which is amply supported by the record. A utility's ROE "sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk."[317] As Company witness Mr. Heath explains:

> Capital structure and return on equity are important components of credit quality. . . . An adequate ROE will allow the Company to generate earnings and cash flows to properly compensate equity investors for their capital at risk while protecting debt investors with a higher degree of credit quality. High credit quality improves financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs.[318]

ROEs are closely scrutinized by investors and financial analysts alike, as a utility's ROE has a meaningful impact upon investment decisions and the ability of a utility to attract capital, which is necessary for the provision of cost-effective, safe, and reliable service to its customers.[319]

In this proceeding, Duke Energy Kentucky is seeking an ROE within the range of current *forward-looking* model outputs. Given Duke Energy Kentucky's small size and risks related to its aging facilities and environmental risk profile, combined with

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[315] Hudson Rebuttal at 5-6.
[316] Joshua C. Nowak Direct Testimony at 4 (Nowak Direct) (Dec. 2, 2024).
[317] *Id.*
[318] Heath Direct at 11-12.
[319] *Id.* at 5.

comparable overall regulatory mechanisms (such as a forward looking test year but with average rate base and limited cost recovery mechanisms), it is appropriate to award Duke Energy Kentucky an ROE that is aligned with the results of multiple established and well-respected methodologies. As a result, and as discussed in further detail below, the Company's ROE should be authorized at 10.85 percent.

i. ROE Models and Reliable Data

Duke Energy Kentucky utilized four different ROE modeling methodologies to determine its requested ROE of 10.85 percent: the Constant Growth Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Bond Yield Plus Risk Premium (Risk Premium) model, and as a benchmark, the Expected Earnings analysis.[320] Use of these methodologies in combination is helpful to determining a fair and reasonable ROE.[321] The Company's requested ROE is therefore based on the range of results produced by the four methodologies indicated above.[322] General economic and capital market environments and the influence of capital market conditions on the aforementioned methods are also relevant to the ROE analysis, as is the Company's business and regulatory risk relative to a set of proxy companies (whether or not a specific adjustment to the ROE model outputs is applied).[323] Overall, Company witness Joshua C. Nowak considered all of these factors and used multiple methodologies supported by multiple jurisdictions in order to assure reasonable results. In contrast, the OAG relied on only two methodologies (one that the OAG witness previously rejected when it yielded higher results), and Walmart relied solely on averages of past commission ROE decisions.

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[320] Nowak Direct at 3–4.
[321] *See id.* at 5
[322] *Id.* at 4.
[323] *Id.* at 5-6.

Additionally, to conduct the ROE analyses described above, Mr. Nowak used a proxy group of companies that each possess a set of business and operating characteristics similar to the Company's vertically-integrated electric utility operations.[324] Using a proxy group of comparable companies provides a reasonable basis for estimating the Company's ROE and mitigates the effects of short-term events that may be associated with any one company.[325] Mr. Nowak used various screening criteria to arrive at a proxy group that investors would view as comparable to Duke Energy Kentucky.[326] Unlike OAG witness Richard A. Baudino, Mr. Nowak did not include Duke Energy Corporation in his proxy group to avoid the circular logic this would create.[327]

Unfortunately, the ROEs proposed by other witnesses are based on the inconsistent use of data. OAG Mr. Baudino, for instance, relied solely on the DCF analysis in Duke Energy Kentucky's last rate case, throwing out his CAPM results that would have significantly increased his overall ROE analytical results.[328] In this case, however, where his multiple CAPM models (some of them wholly new to his testimony in this case) reduce the overall ROE averages, he places equal or greater weight on CAPM than on DCF.[329] Specifically, Mr. Baudino calculates the average of the average of two DCF methods resulting in a 9.92 percent average ROE, and the average of eight individual CAPM models resulting in a 9.33 percent average (well below market), and then simply takes the midpoint of the DCF and CAPM averages to reach his 9.65 percent outcome.[330] Further, Mr. Baudino takes this approach at the same time he continues to state concerns with CAPM models

[324] Nowak Direct at 26-27.
[325] *Id.*
[326] *Id.* at 24-25.
[327] *Id.* at 25.
[328] Baudino Cross, HVR at 4:20 (May 22, 2025).
[329] Baudino Direct at 33, Table 1.
[330] *Id.*

throughout his testimony in the proceeding.[331] So while the Company supports the use of multiple legitimate models to arrive at a reasonable authorized ROE, Mr. Baudino's aforementioned and results-driven approach is neither internally consistent nor reliable.

A review of Mr. Baudino's models that rely on earnings growth rates – which he agrees with Mr. Nowak are the basis for investor decisions[332] – illustrates that the three Baudino DCF analyses that rely on earnings growth rates average 10.23 precent under Method 1 and 10.27 percent under Method 2.[333] These results are far closer to Mr. Nowak's recommended range and outcome (10.25-11.25 percent range, with a 10.85 percent ROE) than to Mr. Baudino's 9.65 percent recommendation. As such, Mr. Nowak's methodologies are sound, and support the Company's recommended ROE.

ii. Backward-Looking ROE Analyses

Both Mr. Nowak and Mr. Baudino reject the determination of an ROE for the period rates will be in effect (a future period) based solely on actual historical ROE determinations of commissions in other states, which is the approach undertaken by Walmart witness Lisa Perry. Ms. Perry considers only historical ROEs other commissions awarded to vertically integrated electric utilities for the period between 2022 and 2024.[334] Averaging three years of historical data not specific to any state, company, commission, or to investor expectations, Ms. Perry then recommends an ROE of 9.75 percent, equivalent to the ROE for Duke Energy Kentucky last set in 2023. Both Mr. Nowak and Mr. Baudino reject the concept of reliance on historically awarded ROEs. For example, Mr. Baudino opposes the Company's Risk Premium analysis on the grounds that it "suggests that the Commission

[331] *Id.* at 22 (lines 14-15), 23 (lines 19-21), 25, and 27 (lines 4-6).
[332] *Id.* at 38.
[333] *Id.* at Exhibit RAB-3 (Proxy Group DCF Return on Equity).
[334] Lisa V. Perry Direct Testimony at 26-27 (Perry Direct) (Mar. 5, 2025).

should base its ROE determination for Duke Kentucky on the ROE determinations of commissions in other states over a long period of time."[335] While this characterization of the Risk Premium approach is incorrect,[336] it underscores that both Mr. Nowak and Mr. Baudino agree that it is inappropriate to base ROE determinations solely on historical data.

Perhaps more important, Ms. Perry's analysis does not support Walmart's recommendation that the Commission keep Duke Energy Kentucky's ROE at 9.75 (the same level set by this Commission in 2023). Rather, Ms. Perry's own analysis shows that average ROEs for vertically integrated electric utilities rose from 9.60 percent in 2022 to 9.71 percent in 2023 to 9.85 percent in 2024.[337] Thus Walmart's recommendation that the Commission hold the Company's ROE flat in a time of rising ROEs, and below average ROEs from the most recent calendar year, is not reasonable.

Ms. Perry also failed to perform any market-based analyses to assess past authorized ROEs relative to the current or future environment in which the Company will be working to attract investors.[338] Further, Ms. Perry offers no analysis tending to show that Duke Energy Kentucky is less risky than its peers that would justify setting Duke Energy Kentucky's ROE lower than that set for vertically integrated utilities in the last year, and in fact witnesses Baudino and Nowak agreed that no specific downward nor upward adjustment for risk is appropriate.[339] Failure to conduct additional (or any) analyses

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[335] Baudino Direct at 44.

[336] Nowak Direct at 21 ("My Bond Yield Plus Risk Premium analysis is designed to do exactly what Mr. Baudino suggests it cannot – that is, use the historical relationship between bond yields and equity risk premia to predict how investors will react to changes in interest rates as a result of monetary policy and economic conditions.").

[337] Perry Direct at Exhibit LVP-2, p. 4 of 4. (Further, Ms. Perry's comparison of vertically integrated ROEs from 2022 through early 2025 is understated, because she included data points from Green Mountain Power of Vermont that collectively pulled down the average, and which does not own active generation and therefore is not a vertically integrated electric utility); Perry Cross, HVR at 4:52 (May 22, 2025).

[338] Perry Direct at 10; Perry Cross, HVR at 4:55.

[339] Nowak Direct at 42; Baudino Direct at 46.

using different methodologies results in an overly narrow historical view and, in turn, imprecise ROE recommendations.

The largest issues with Ms. Perry's analysis, however, is that it reflects ROEs set under considerably different capital market conditions that have little bearing on the returns required by investors in the current capital market. As discussed above, Ms. Perry failed to fully consider and analyze changing capital market conditions that influence the Company's ROE. Authorized ROEs from 2022 through 2024, when interest rates were significantly lower than now and reflected a more stable market environment, are not a reasonable comparison for evaluating the cost of equity in the current capital market environment.[340] As noted by Mr. Nowak, investors are much more interested in current capital market conditions and conditions going forward.[341] In 2025, there has been in increase in interest rates and an expectation that interest rates will remain elevated.[342] In addition, the Chicago Board Options Exchange Volatility Index or "VIX Index," which forecasts expected volatility in the market for the next 30 days in the future, has been elevated recently demonstrating the potential for future volatility in the capital market.[343] Historically, the normal range of the VIX Index is between 15-20 but during COVID-19, the VIX Index reached 80.[344] In early April 2025, the VIX Index reached a level of 50 which is a significant deviation from the normal and, while it has gone down since then,

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340 Nowak Rebuttal at 5*; see also* Nowak Cross, HVR at 22:29 (May 22, 2025) (Commissioner Regan asked Mr. Nowak whether he still stands by his statement that "Fitch Ratings points to capital spending, elevated interest rates, and high fuel prices creating cost pressures leading to a 'deteriorating' outlook on the utility sector" in the current marketplace in terms of tariffs and bonds. Mr. Nowak said all of his analyses were done prior to the current volatile conditions, however if those conditions continue, there will be an upward pressure on the cost of capital.).
341 Nowak Cross, HVR at 20:50 (May 22, 2025).
342 Nowak Cross, HVR at 21:00 (May 22, 2025).
343 Nowak Cross, HVR at 25:20 (May 22, 2025).
344 Nowak Cross, HVR at 25:32 (May 22, 2025).

the VIX Index has remained elevated in 2025.[345] Refusal to acknowledge recent changes in capital market conditions and analyze various risk factors as they relate to the Company in this proceeding downplays key risk factors relevant to the Company's operations and position in the capital marketplace. This, in turn, creates ROE recommendations based on incomplete information. Mr. Nowak presents the most complete, robust, and reliable forward-looking analysis, such that his 10.85 percent ROE should be adopted.

b. Capital Structure

Duke Energy Kentucky's capital structure proposed for this case is comprised of 52.728 percent equity and 47.272 percent debt.[346] This proposed capital structure is appropriate for Duke Energy Kentucky, as it introduces the appropriate amount of risk due to leverage and minimizes the weighted average cost of capital to customers.[347] Approval of the proposed capital structure will help Duke Energy Kentucky maintain its credit quality and is consistent with Duke Energy's target credit ratings for Duke Energy Kentucky.[348]

At the outset of this proceeding, the Company has BBB+ and Baa1 credit ratings from S&P and Moody's, respectively, with "Stable" outlooks for each credit agency.[349] The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years).[350] A "Stable" outlook at S&P and Moody's is an indication that the credit ratings are not likely to change in the immediate

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[345] Nowak Cross, HVR at 20:54 (May 22, 2025).
[346] Heath Direct at 6.
[347] *Id.*
[348] *Id.*
[349] *Id.* at 8.
[350] *Id.* at 9.

term.[351] That said, a change in outlook could occur if the Company experiences a change in its business, regulatory, or financial risk.[352]

On May 13, 2024, Moody's affirmed Duke Energy Kentucky's Baa1 senior unsecured rating and changed its outlook to "stable" from "negative."[353] In its May 2024 Duke Energy Kentucky report, Moody attributed the outlook change to "the expectation that a credit supportive outcome in the utility's most recent [2022] electric rate case will support credit metrics appropriate for its Baa1 rating."[354]

OAG witness Mr. Baudino testified to the Company's proposed capital structure for the 2026 forecast period which includes a common equity ratio of 52.728 percent.[355] He testified that this number was adjusted downward from the base period common equity ratio of 54.50 percent and explained that the OAG does not oppose Duke Energy Kentucky's requested capital structure.[356] Neither Walmart nor Kroger filed any testimony related to the Company's proposed capital structure. As such, there is no dispute in the proceeding regarding the appropriate capital structure.

5. Class Cost of Service Study (CCOSS)

A Class Cost of Service Study (CCOSS) is an analytical tool used to allocate costs to different classes of customers. As part of its Application, the Company prepared three CCOSSs; each used the same data but a different methodology to develop the allocation factor for the demand component of production-related costs.[357] The demand allocation methods are: (1) the Average of the Twelve Coincident Peaks (12 CP) method; (2) the

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[351] *Id.*
[352] *Id.*
[353] *Id.* at 9.
[354] *Id.* (quoting May 2024 Moody's Duke Energy Kentucky Report).
[355] Baudino Direct at 36.
[356] *Id.*
[357] James E. Ziolkowski Direct Testimony at 5 (Ziolkowski Direct) (Dec. 2, 2025).

Average and Excess (A&E) method; and (3) the Production Stacking method.[358] The Company recommends using the 12 CP method to allocate production plant costs because it best aligns capacity costs with the customer classes that are imposing those costs.[359] This method also results in a residential rate increase that falls between the increases that would result from the other two methods.[360] The A&E method results in a residential increase of 18.8 percent, the Production Stacking method results in a residential rate increase of 15.8 percent, and the 12 CP method results in a residential rate increase of 16.8 percent.[361] Kroger witness Mr. Justin Bieber agrees that the 12 CP method is reasonable to use in this case given the Commission's approval of the 12 CP method in the Company's prior rate cases and the nature of Duke Energy Kentucky's system peaks.[362] Additionally, Walmart witness Perry does not oppose use of the 12 CP methodology.[363] As such, the CCOSS using the 12 CP method should be used as the basis for rate design in this proceeding.

6. Revenue Allocation and Proposed Rate Design

A general tenet of ratemaking is that each customer class should, to the extent practicable, pay the costs of providing service to that class.[364] Duke Energy Kentucky used the CCOSS as a basis of the Company's proposed rate design. The Company's CCOSS revealed that there are significant differences among rate classes when comparing the actual return earned by each rate class to the 7.968 percent overall return on rate base being requested in this case.[365] In other words, developing rates that generate the amount of

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[358] *Id.*
[359] *Id.* at 9.
[360] *Id.*
[361] *Id.* at 9.
[362] Justin D. Bieber Direct Testimony at 8 (Bieber Direct) (Mar. 5, 2025).
[363] Perry Direct at 20.
[364] Ziolkowski Direct at 32.
[365] *Id.* at 31.

revenue that equals the allocated revenue requirement for each rate class will mean much greater relative increases for some rate classes than others in order to match class revenue responsibility with underlying cost causation.[366]

To mitigate any rate shock that may occur from completely eliminating interclass subsidies, the Company proposes a two-step process to distribute the proposed revenue increase.[367] The first step involves eliminating 15 percent of the subsidy/excess revenues between customer classes based on present revenues.[368] The second step then allocates the rate increase to customer classes based on electric original cost depreciated (OCD) rate base.[369] While this proposal lets a subsidy/excess persist, it will reduce the gap so that each class is paying rates that more closely reflect their cost of service while mitigating rate shocks customers may otherwise experience from sudden increases in their electric bills.[370]

Walmart does not oppose the Company's revenue allocation proposal so long as the Commission authorizes the Company its full proposed revenue requirement increase.[371] Walmart only recommends changes to the Company's revenue apportionment among classes if the Commission approves a revenue requirement lower than that requested by the Company.[372] In that event, Walmart recommends that the Commission should take steps to further reduce interclass subsidies.[373] Specifically, Walmart recommends that the Commission should apply 50 percent of the overall revenue reduction (difference between requested and authorized revenue requirement) to those rate classes who are paying in

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[366] *Id.*
[367] *Id.*
[368] *Id.*
[369] *Id.*
[370] *Id.*
[371] Perry Direct at 24.
[372] *Id.*
[373] *Id.*

excess of their cost-based levels and then the remaining amount should be evenly applied to all rate classes.[374] As noted above, the Company's proposed rate design is both aligned with its CCOSS results and the regulatory principles of gradualism and rate shock mitigation, the Company urges the Commission to approve its requested rate design regardless of the final authorized revenue requirement, including the proposed change to Rate DS discussed in the next section of this brief.

a. Rate DS Rate Design

Rate DS is the Service at Secondary Distribution Voltage rate schedule. Rate DS is applicable to non-residential customers with an average monthly demand less than 500 kW.[375] The rate components for Rate DS include a customer charge, a two block demand charge, and a three block energy charge. For the Rate DS energy charges, Duke Energy Kentucky uses load factor blocking, with the Block 1 rate applied to the first 6,000 kWh, the Block 2 rate applied to the next 300 kWh per kW, and the Block 3 rate applied to all additional kWh.[376] For the Rate DS demand charges, Duke Energy Kentucky charges $0 for the first 15 kW of billing demand And the Block 2 demand rate applies to all additional kW over 15 kW.

In its Application, Duke Energy Kentucky proposed to maintain the current customer charges and recover the proposed increase for Rate DS through an approximately equal percentage increase to each of the demand and energy rate components.[377] In its direct testimony, Kroger recommends increasing the Company's proposed Block 2 demand charge for Rate DS to $15.85 per kW, with a corresponding revenue-neutral decrease to

[374] *Id.*
[375] Bieber Direct at12.
[376] *Id.*
[377] Bieber Direct at 13.

the Block 1, Block 2, and Block 3 energy charges.[378] Kroger also recommends maintaining the Company's proposed differential, or premium, between the Block 1, Block 2, and Block 3 energy rates for Rate DS but did not recommend any changes to Duke Energy Kentucky's proposed Rate DS customer charges.[379] In rebuttal testimony, the Company opposed Kroger's proposed changes to the demand and energy charges for Rate DS.[380] The Company opposed Kroger's changes because decreasing all three blocks of the energy charges for Rate DS, while increasing only the Block 2 demand charge, would mean that smaller Rate DS customers, particularly those with demand less than or equal to 15 kW, would receive a smaller bill increase and may not pay their fair share of their cost of service.[381] This is because Rate DS is designed to allow the Company to recover all demand-related revenues for the first 15 kW for all Rate DS customers through energy and fixed customer charges.[382] However, Company witness Bruce L. Sailers testified that the Company might be amenable to making changes to only the Block 3 energy charge so long as that charge is not reduced below the cost of service study energy component divided by the total class kWh.[383]

During the hearing, Company witness Mr. Sailers testified that the Company would be agreeable to reduce the Block 3 energy charge for Rate DS to an energy charge calculated by taking the total energy revenue requirement for Rate DS from the cost of service divided by total Rate DS kWh as long as there is a corresponding revenue increase in the Block 2 demand charge for Rate DS customers.[384] During his live testimony, Kroger

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[378] *Id.* at 18.
[379] *Id.*
[380] Bruce L. Sailers Rebuttal Testimony at 5 (Sailers Rebuttal) (Apr. 9, 2025).
[381] Sailers Rebuttal at 6.
[382] Sailers Rebuttal at 6-7.
[383] Sailers Rebuttal at 7.
[384] Sailers Cross, HVR at 2:00 (May 22, 2025)

witness Mr. Bieber agreed with the Company's proposed changes to Rate DS.[385] The Commission should adopt changes to Rate DS consistent with the proposal made by the Company during the hearing.

b. Proposed Changes to Reconnection Fees

The Company proposed to increase the remote reconnection charge to $6.50, decrease the non-remote reconnection charge at the meter to $5.80, and decrease the non-remote reconnection charge at the pole to $16.50.[386] As directed by the Commission in Case No. 2022-00372, all internal labor costs have been removed from these charges. The Company also proposed to eliminate the after-hours charge due to the infrequent need for this charge.[387] No party opposed the proposed changes to reconnection fees and the Commission should approve the Company's proposed changes.

c. Proposed Changes to Pole Attachment Fees

The Company completed a pole attachment study as ordered in the 2022 Rate Case utilizing all pole lengths.[388] The results of this study showed that using the 2-user and 3-user categories, as utilized in the past, results in charges of $7.42 per foot and $7.84 per foot respectively.[389] Based on the results of the study, the Company proposes that using all pole lengths converges the 2-user and 3-user charges and therefore, it is reasonable and simplifies administration if the two categories are combined into one charge per foot for all pole attachments.[390] No party opposed the Company's proposed changes to its pole attachment fees and the Commission should approve the Company's proposed changes.

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[385] Bieber Cross, HVR at 4:43 (May 22, 2025).
[386] *Id*. at 15.
[387] *Id*.
[388] *Id*.
[389] *Id*. at 16.
[390] *Id*.

7. Proposed Tariff Changes

a. New Large Customer Loads

In order to protect existing customers and the Company from the potential of being saddled with the costs for significant infrastructure to support new large loads that never materialize, Duke Energy Kentucky proposed to add language to its existing Rate DT and Rate TT for new large load customers.[391] This new language would apply to any new loads of 20 MW or more where significant system investments, $1 million or more, are required to connect this new load to the system.[392] For new loads that meet this criteria, the Company proposed to require a service agreement with the customer that will specify credit requirements, minimum demand charges of 75 percent of the customer-specified load requirement, and associated termination provisions.[393] These individual new large load customer service agreements would be subject to Commission approval.[394]

In its direct testimony, Walmart expressed concern that the Company's 20 MW threshold was too low and could unintentionally include customers that are not typically considered "large load customers."[395] Walmart instead proposed a higher threshold of 75 MW.[396] In rebuttal testimony, the Company expressed concern that Walmart's 75 MW threshold for new large load was too high. Specifically, the Company noted that the addition of a new 75 MW load would represent a 8 percent increase in Duke Energy

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[391] *Id.* at 11.
[392] *Id.*; Duke Energy Kentucky's Response to Walmart's Second Request for Information, Item 3 (Filed Feb. 12, 2025) ("Consistent with the Company's line extension policy which focuses on changes to the Company's distribution system, a significant system investment in the proposed Rate DT and Rate TT tariff sheets is considered to be $1 million or more in total production and transmission system investment.")..
[393] Sailers Direct at 11.
[394] *Id.*
[395] Perry Direct at 27.
[396] *Id.*

Kentucky's total system peak load.[397] While the Company stated its objection to a 75 MW threshold, during the hearing, Company witness Sailers agreed that a threshold of 40 MW would be acceptable and would strike an appropriate balance between Walmart's concerns and protecting existing customers from the potential for stranded costs associated with new large load customers.[398] The Commission should therefore approve the Company's proposed new tariff language for Rate DT and Rate TT for new large load customers with a 40 MW threshold.

b. Public-Facing Electric Vehicle (EV) Charger Rate

In this proceeding, Walmart expressed interest in Duke Energy Kentucky developing a new rate for customers who own and operate public EV charging equipment, specifically Direct Current Fact Chargers (DCFC).[399] Walmart is interested in the development of this new rate as it has recently announced plans to build its own EV fast charging network at thousands of Walmart and Sam's Club locations across the country over the next few years.[400] Walmart is developing this charging network to support greater EV adoption and as a convenience to customers who own EVs.[401] In its direct testimony, Walmart recommended that the Commission require Duke Energy Kentucky to work with interested stakeholders to develop a new EV rate for public-facing EV chargers and to either seek Commission approval of the new rate or provide an update on the stakeholder process within six months of the Commission's final order in this case.[402]

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[397] Sailers Rebuttal at 2.
[398] Sailers Cross, HVR at 2:07 (May 22, 2025).
[399] Perry Direct at 27.
[400] *Id.* at 28.
[401] *Id.*
[402] *Id.* at 30.

In its rebuttal testimony, Duke Energy Kentucky stated that it was opposed to the development of such a rate if the intent was to provide discounted rates to these EV charging customers, *i.e.*, rates that are not aligned with the cost to serve the EV chargers.[403] The Company also noted that it currently has several existing rate offerings that would work well for customers with public facing DCFC charging stations.[404] Duke Energy Kentucky did, however, state that it would be willing to meet with Walmart to discuss non-discriminatory rate designs suitable for public facing DCFC chargers and would include an update on such discussions in its next electric rate case filing.[405] During the hearing, Duke Energy Kentucky confirmed its agreement to meet with Walmart to discuss a potential revenue neutral rate suitable for public facing DCFC chargers and to file such rate prior to its next rate case if such a rate is developed.[406]

B. Other Issues

1. Comprehensive Hedging Program

The Company is proposing to hedge its power position during forced outages and economic hedging when the PJM AEP-Dayton (AD) hub market power price is under the projected cost of production.[407] OAG witness Mr. Kollen recommends that the Commission deny the Company's hedging program request and instead direct the Company to initiate a new proceeding to consider the scope and long-term cost effectiveness of the proposed comprehensive hedging program.[408] Mr. Kollen has three primary objections to the Company's proposal for a comprehensive hedging program. First,

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[403] Sailers Direct at 4.
[404] *Id.*
[405] *Id.*
[406] Sailers Cross, HVR at 2:03 (May 22, 2025).
[407] James J. McClay Direct Testimony at 5 (McClay Direct) (Dec. 2, 2024).
[408] Kollen Direct at 9.

Mr. Kollen claims that the Company did not provide a detailed description of the Company's proposed new comprehensive hedging program in its Application.[409] Second, Mr. Kollen argues that a seller will price call options at "an expected cost greater than if the Company incurred market prices without purchasing hedging products."[410] Third, Mr. Kollen argues that the Company did not provide "economic and/or other analytical studies that compare outcomes with and without the proposed comprehensive hedging program."[411] These arguments are without merit.

Company witness James J. McClay explained that the new comprehensive hedging program builds on the existing hedging program, including the instruments and strategies for scheduled outages successfully employed by the Company since its first Back-up Power Supply Plan in 2007.[412] The Company has used, for many years, fixed-priced financial hedging instruments for scheduled outages.[413] These are power financial swap and future contract products listed on Intercontinental Exchange (ICE) or through the bilateral over-the-counter (OTC) broker market. The Company plans to use these same tools for its proposed comprehensive hedging program.[414]

In addition, while there are transaction costs to purchase hedging products on ICE, the OTC market, or other trading platforms, these are standardized transaction costs paid by every market participant at same rates, similar to administration fees charged by PJM for Regional Transmission Organization (RTO) transactions.[415] Mr. Kollen's argument that a seller will price call options at "an expected cost greater than if the Company incurred

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[409] *Id.* at 55–56.
[410] *Id.* at 57.
[411] *Id.* at 56-57.
[412] James J. McClay Rebuttal Testimony at 3 (McClay Rebuttal) (Apr. 9, 2025).
[413] *Id.*
[414] *Id.*
[415] *Id.* at 4.

market prices without purchasing hedging products" is not valid and is irrelevant to the Company's proposal because the Company will continue to use financial swap and future contract products listed on ICE or through the bilateral OTC broker market.[416] These are not call options as described by Mr. Kollen. In fact, in preparation for past Back-up Power Supply Plan filings, the Company solicited quotes, on multiple occasions, for various types of call options and reached the same conclusion as Mr. Kollen that call options, by themselves, are not economic hedging tools.[417]

Finally, the Company has a long history of hedging scheduled outages that illustrates the benefits to customers. In the past 18 years, from 2007 through 2024, the Company purchased forward hedges for East Bend's scheduled outages days or months ahead of time, paid the then-market prevailing price, and settled against hourly PJM AEP-Dayton Hub LMPs while the unit was not available.[418] Over this period, the net result, after all transaction costs including commissions and ICE fees, was a net gain or savings to customers of $2,882,681.[419]

The Company maintains that its hedging proposal is reasonable, is in the best interests of customers, and should be approved. Through its active participation in the PJM and MISO Energy markets, the Company has witnessed significant market price volatility inherent in organized energy markets.[420] A more comprehensive hedging plan is a proactive measure to mitigate exposure to volatile spot energy prices and improve price certainty for customers.[421] The proposed hedging plan is essential for maintaining price stability,

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[416] *Id.*
[417] *Id.*
[418] *Id.* at 5.
[419] *Id.*
[420] *Id.* at 2.
[421] *Id.* at 6.

protecting customers from market price volatility, and helping mitigate overall electricity costs.[422] Therefore, the Commission should approve the Company's hedging proposal and include both gains and losses of the financial hedging proposal through the FAC. Forced outage power replacement costs from PJM would be recovered either through base rates or FAC subject to 807 KAR 5:056.

2. Proposed Gas Management Program

The Company is requesting the ability to sell surplus gas purchased but unable to be burned through commodity sales and to have the net proceeds (difference between purchase price and sale price), positive or negative, recovered through the Profit Sharing Mechanism (PSM) rider.[423] The Company's current methodology is to park unused gas on the TETCO pipeline.[424] OAG witness Mr. Kollen recommends that the Commission deny the Company's request for approval of its proposed gas management program and the refund or recovery of gains or losses through the FAC.[425] Mr. Kollen's recommendation appears to be based on a misconception that TETCO natural gas pipeline operations will continue to allow the Company unlimited flexibility in managing its physical natural gas supply in perpetuity. However, Company witness Mr. McClay discussed that the Company's current method is a short-term solution.[426] As natural gas consumption for electric generation has increased, the Company is continuing to see a decrease in the pipeline operational flexibility that the Company has been using to manage its natural gas supply.[427] It is unreasonable to assume that gas pipelines, including TETCO, will continue

[422] *Id.*
[423] *Id.* at 7.
[424] *Id.*
[425] Kollen Direct at 9.
[426] McClay Rebuttal at 7.
[427] *Id.*

to indefinitely allow unlimited flexibility.[428] The flexibility to sell excess natural gas is a valuable tool used by the industry to help balance supply and demand changes and ultimately customer costs.[429] The Company is asking for the ability, when it makes economic sense, to sell natural gas so that customers may have the opportunity to benefit from the Company's optimization of its natural gas position.[430] The Commission should approve the Company's request to sell surplus natural gas purchased but unable to be burned through commodity sales and to have the net proceeds (difference between purchase price and sale price), positive or negative, recovered through the PSM.

3. Proposed Capacity Performance Insurance

The Company is proposing that in the event it decides to purchase Capacity Performance (CP) insurance, CP insurance premium costs and proceeds be included in the PSM. Company witness Mr. McClay explained that the Company has a relatively concentrated portfolio where one generation asset, East Bend (600 MW ICAP), stands for more than 50 percent of the portfolio capacity.[431] If this unit is not available during CP events, the rest of the Duke Energy Kentucky generation fleet (Woodsdale CT1-6, total approximately 476MW ICAP) will not be able to offset East Bend's non-performance.[432] Purchasing a CP insurance policy may help mitigate a potential catastrophic cost to customers, should East Bend be unavailable during a PJM CP event.[433] Under the current PSM, customers bear 90 percent of the benefit and risk of CP impacts (credits and costs).[434]

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[428] *Id.* at 8.
[429] *Id.* at 9.
[430] *Id.* at 9–10.
[431] *Id.* at 10.
[432] *Id.*
[433] *Id.*
[434] *Id.* at 11.

A CP insurance product would provide customers with proportional coverage for that risk.[435]

PJM capacity prices significantly increased in the most recent base residual auction (BRA) and are expected to continue to rise.[436] The stop loss, or the maximum that an entity can be charged for a CP penalty, is tied to the auction clearing price.[437] Therefore, the higher the auction clearing price, the higher stop loss, and thus the higher the potential CP penalty.[438] This is true regardless of whether the Company is a Fixed Resource Requirement (FRR) or a full Reliability Pricing Model (RPM) BRA participant.[439] Given that PJM capacity prices in the BRA have risen significantly and are likely to continue to increase, the Company expects to continue evaluating the potential purchase of CP insurance to mitigate the increased customer penalty risk should a CP event occur.[440]

Since CP insurance is specifically designed to mitigate CP nonperformance charges, it is appropriate for the Commission to approve the inclusion of mitigation costs and benefits in the PSM with the CP nonperformance charges being mitigated.[441] In the event a CP nonperformance charge was levied by PJM, the CP insurance payout would offset the charge, reducing the total amount to flow through PSM.[442] Accordingly, the Commission should approve the Company's proposal to purchase CP insurance and recover the expense through the PSM.

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[435] *Id.*
[436] McClay Direct at 19.
[437] *Id.*
[438] *Id.*
[439] McClay Rebuttal at 13.
[440] *Id.*
[441] *Id.* at 13–14.
[442] *Id.* at 14.

4. Proposed PJM Billing Codes Changes in FAC and PSM Riders

PJM is the nation's first fully functioning RTO. PJM operates the power grid and wholesale electric market for all or parts of thirteen states and the District of Columbia.[443] This electric market consists of a capacity market, energy market, Ancillary Service Market (ASM), and a Financial Transmission Rights (FTR) market.[444] PJM's operation is governed by agreements and tariffs approved by the FERC.[445]

PJM has a standard and robust process for accounting for all costs and credits accrued in participation of its markets.[446] All costs and credits accrued as a member of PJM are invoiced weekly with a monthly true-up and settled by PJM through Billing Line Items (BLIs).[447] The monthly bill includes a detailed listing of the different BLIs, with BLIs that start with a 1000 designation as costs, BLIs that start with a 2000 designation as credits, BLIs that start with a 1400 designation as a reconciliation of a cost, and BLIs that start with a 2400 designation as a reconciliation of a credit.[448] Reconciliations for costs and credits are necessary since PJM calculates load reconciliations on a two- or three-month lag as new meter data is received.[449] A reconciliation is essentially a "true-up" for changes to meter data as it relates to specific 1000 costs or 2000 credits.[450] The Company recovers these PJM BLIs through the FAC and PSM, as well as base rates.[451] In Case No. 2017-00321, the Commission approved certain PJM BLIs to be recovered in the FAC and

443 Swez Direct at 5.
444 *Id.*
445 *Id.*
446 *Id.* at 35.
447 *Id.*
448 *Id.*
449 *Id.*
450 *Id.*
451 *Id.* at 37.

PSM.[452] Since that case was decided, PJM has added, eliminated, and bifurcated certain BLIs.[453] The Commission has previously ordered that the Company is not allowed to change any of the BLIs included in the FAC or PSM without prior Commission approval.[454]

In this proceeding, the Company is requesting that the Commission authorize updates to the PJM BLI codes included in the Company's FAC and PSM to reflect updates to these codes. The direct testimony of Company witness Mr. Swez provided a detailed summary of each of the PJM codes that the Company seeks to add or modify in the FAC and PJM riders.[455]

The OAG opposed the Company's request alleging that it is duplicative and unnecessary as the Company made the same request in another recent proceeding, Case No. 2024-00285.[456] This other proceeding related to the Company's request to exit the FRR plan and transition to full participation in PJM's RPM or the "FRR to RPM proceeding." As explained by Company witness Ms. Steinkuhl, the Company's request in this proceeding is not the same as its requests in the FRR to RPM proceeding. The Company's request in the FRR to RPM proceeding only addressed PJM BLIs related to becoming a RPM participant.[457] The Company's request in this rate case did not involve any BLIs related to becoming an RPM participant because the Company is currently an FRR participant and, at the time the Application was filed in December 2024, the

[452] Case No. 2017-00321, *Electronic Application for Duke Energy Kentucky, Inc., for (1) An Adjustment of 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*, Order at 13 (Ky. PSC Oct. 2, 2018).
[453] Swez Direct at 38.
[454] *Id.*; Case No. 2021-00296, *Electronic Examination of the Application of the Fuel Adjustment Clause of Duke Energy Kentucky, Inc. from November 1, 2020 through April 30, 2021,* Order (Ky. PSC March 24, 2022).
[455] Swez Direct at 38-47.
[456] Kollen Direct at 62-63.
[457] Steinkuhl Rebuttal at 16.

Commission had not yet issued an order in that proceeding.[458] In addition, the Company did not request any changes to the PJM BLIs included in the FAC as part of the FRR to RPM proceeding.[459] As the Company's requests to update its PJM BLIs in its FAC and PSM are different from those requested in the RPM to FRR proceeding, the Commission should authorize the Company's proposed changes.

The OAG further recommended that to the extent that the Commission adopted its recommendations in the FRR to RPM proceeding, that the Commission incorporate these same recommendations in this proceeding.[460] The Commission recently issued its decision in the FRR to RPM case, responding to the OAG's proposed conditions in that case. Although the Commission conditioned its approval on several protections to customers, it declined to adopt all of the recommendations made by the OAG. Repeating or reconsidering those conditions here is unnecessarily duplicative and inefficient.[461]

IV. CONCLUSION

WHEREFORE, on the basis of the foregoing, Duke Energy Kentucky respectfully requests that the Commission declare and award the following relief:

A. The Company's rates shall be set to increase revenue by $69,986,788 using a valuation based upon rate base and an ROE of 10.85 percent;

B. The Company's rate base shall be approved as filed except for the

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[458] *Id.*; Case No. 2024-00285, *Electronic Application of Duke Energy Kentucky, Inc. to Become a Full Participant in the PJM Interconnection LLC, Base Residual and Incremental Auction Construct for the 2027/2028 Delivery Year and for Necessary Accounting and Tariff Changes,* Order (Ky. PSC May 16, 2025).
[459] Steinkuhl Rebuttal at 17.
[460] Kollen Direct at 63.
[461] Case No. 2024-00285, *Electronic Application of Duke Energy Kentucky, Inc. to Become a Full Participant in the PJM Interconnection LLC, Base Residual and Incremental Auction Construct for the 2027/2028 Delivery Year and for Necessary Accounting and Tariff Changes,* Order at 31 (Ky. PSC May 16, 2025) ("Because the Commission is not approving the inclusion of the performance related BLIs into the Rider PSM, the Commission will not specifically address each of the OAG's concerns and proposed guardrails explicitly.").

adjustments agreed to by Duke Energy Kentucky in rebuttal testimony;

C. The Company is authorized to create two deferral mechanisms, one for planned outage O&M expense and another for forced outage replacement purchased power expense;

D. The Company is authorized to amortize the remaining regulatory asset balance for planned O&M outage expense, January 1, 2022 through October 12, 2023, and forced outage replacement purchased power expense, July 1, 2022 through October 12, 2023, over five years;

E. The Company's depreciation rates, which include appropriate decommissioning expense as part of those rates, for East Bend, Woodsdale, and the Company's solar assets, shall be approved as provided for in the Application, and the depreciation rates for East Bend shall be aligned with its projected retirement date of December 31, 2038;

F. The Company is authorized to amortize its estimated rate case expense for this case over a five-year period and to recover the unamortized balance of rate case expense from the 2022 Rate Case as provided for in the Application;

G. The Company is authorized to eliminate the transaction convenience fee paid by residential customers for each Card Payment and to include these costs in the Company's cost of service.

H. The Company is authorized to implement and manage its proposed capital structure, including an authorized equity ratio of 52.728 percent;

I. The Company's CCOSS using the 12 CP method and the Company's requested revenue requirement apportionment among rate classes shall be approved;

J. The Company's proposed monthly customer charges shall be approved as provided for in the Application;

K. For Rate DS, the Block 3 energy charge shall be reduced to an energy charge calculated by taking the total energy revenue requirement for Rate DS from the cost of service divided by total Rate DS kWh as long as there is a corresponding increase in the demand charge for Rate DS customers with demand less than or equal to 15 kW;

L. The Company's proposed changes to street lighting tariffs, reconnection fees, and pole attachment charges shall be approved as provided for in the Application;

M. The Company's proposed changes to existing Rate DT and Rate TT for new large load customers are approved with a 40 MW threshold for applicability;

N. The Company's request to implement a comprehensive hedging strategy shall be approved as provided for in the Application;

O. The Company is authorized to sell surplus gas purchased but unable to be burned through commodity sales and to have the net proceeds, positive or negative, recovered through the PSM;

P. The Company is authorized to purchase CP insurance, and include the premium costs and proceeds in the PSM;

Q. The Company's proposed changes to the PJM BLI codes included in the FAC and PSM are approved;

R. Unless otherwise stated, all other provisions of the Company's Application shall be approved as filed; and

S. Any other relief to which the Company may be entitled shall be awarded.

This 16th day of June 2025.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document in paper medium; that the electronic filing was transmitted to the Commission on June 16, 2025; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that submitting the original filing to the Commission in paper medium is no longer required as it has been granted a permanent deviation.[462]

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[462] Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, Order (Ky. PSC July 22, 2021).