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. 2022-00372

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 15, 2023 Order of the Kentucky Public Service Commission (the 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 seeks to increase its electric base rates by $68.82 million,[1] representing a 16.3 percent overall increase in customer rates. The most significant drivers of this requested increase are an increase in depreciation expense and growth in rate base of approximately $300 million since the time of the Company's last electric base rate case (the 2019 Rate Case).[2] This is the result of much needed investments for the Company to continue to provide safe and reliable service to its customers.[3]

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[1] Lisa D. Steinkuhl Revised Rebuttal Testimony (Steinkuhl Revised Rebuttal), p. 7 (May 5, 2023).
[2] Sarah E. Lawler Direct Testimony (Lawler Direct), p. 4 (Dec. 1, 2022).
[3] *Id.*

An important issue in this proceeding is the Company's request to align its depreciation rates with probable generating asset retirement dates so as to avoid inappropriate cost shifting to future customers.[4] Because the Commission denied the Company's request to update its depreciation rates in the 2019 Rate Case,[5] the depreciation rates for the Company's East Bend Generating Station (East Bend) and Woodsdale Generating Station (Woodsdale) do not align with their previously estimated end-of-service lives.[6] This creates substantial exposure for future customers to assume the costs for assets at the time they are retired.[7] Due to new developments since the 2019 Rate Case, East Bend is now projected to retire by 2035, earlier than what was previously contemplated in the Company's 2019 Rate Case, and Woodsdale is now projected to retire by 2040, later than what was previously contemplated in the 2019 Rate Case.[8] Additional factors, such as subsidies provided to low- and no-carbon emitting resources, will make the operation of fossil fuel generation less economic over time.[9] Kentucky Senate Bill 4 (SB 4)—which is intended to ensure fossil generation remains viable as long as possible and is only retired when it is cost-effective to do so—makes proper alignment of depreciation expense with an asset's estimated lifespan all the more relevant and imperative to secure affordable electricity for customers in the future.[10] As such, and as explained in further detail in this Brief, the Company is seeking to properly align East Bend's and Woodsdale's depreciation rates with their anticipated service lives.[11] Such alignment is necessary to avoid intergenerational subsidies and protect future

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[4] Amy B. Spiller Direct Testimony (Spiller Direct), p. 25 (Dec. 1, 2022).
[5] *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. 2019-00271, Order, p. 15 (April 27, 2020).
[6] Spiller Direct, p. 25.
[7] *Id.*
[8] *Id.*
[9] *Id.*
[10] Sarah E. Lawler Rebuttal Testimony (Lawler Rebuttal), pp. 7–9 (Apr. 14, 2023).
[11] Spiller Direct, p. 26.

customers by minimizing the amount that they will pay for any post-retirement undepreciated plant remaining after the generating assets' retirement, as well as for their replacement resources.[12]

The Company is also presenting several new and updated initiatives that, if approved, will significantly enhance the Company's provision of service to customers, customers' experiences interfacing with the Company, and the communities that Duke Energy Kentucky serves. These innovative efforts include, but are not limited to: programs and supporting tariffs related to electric vehicle (EV) development that will encourage and assist customers and the broader public in transitioning to electric transportation infrastructure;[13] a new program, Clean Energy Connection, that will support customers who desire to source their generation from renewable resources;[14] a reduction in the late payment charge;[15] and adjustments to the Fuel Adjustment Clause (FAC) Rider to reduce volatility in customer rates.[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 programs, in addition to the increase in base rates set forth above and the other items requested in this Brief.

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]

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[12] *Id*.
[13] *Id.* at pp. 26–27; Cormack C. Gordon Direct Testimony (Gordon Direct), pp. 3–4 (Dec. 1, 2022).
[14] Spiller Direct, p. 27; Paul L. Halstead Direct Testimony (Halstead Direct), p. 2 (Dec. 1, 2022).
[15] Jacob S. Colley Direct Testimony (Colley Direct), p. 14 (Dec. 1, 2022).
[16] Spiller Direct, p. 4.
[17] *Id.* at p. 6.
[18] *Id.*

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 149,200 customers in Boone, Campbell, Grant, Kenton, and Pendleton Counties in Kentucky.[19] The Company also provides natural gas service in Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton Counties to approximately 103,100 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 11,010 Btu/kWh for calendar year 2021.[23] The major pollution control features at East Bend include a high-efficiency hot side electrostatic precipitator, a selective catalytic reduction control (SCR) system designed to reduce nitrogen oxide (NO_x) emissions by 85%, and a flue gas desulfurization (FGD) system designed to remove sulfur dioxide ($S0_2$) emissions to an average of 97%.[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]

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[19] *Id.* at p. 5.
[20] *Id.*
[21] William Luke Direct Testimony (Luke Direct), p. 3 (Dec. 1, 2022).
[22] *Id.*
[23] *Id.*
[24] *Id.*
[25] *Id.*

Based on modeling conducted as part of Duke Energy Kentucky's 2021 integrated resource plan (IRP), the Company presently anticipates retiring East Bend in 2035.[26] There are multiple drivers for this anticipated retirement; most significantly, market pressures are negatively impacting the long-term viability of coal-fired generation.[27] As a result, and as described in further detail in this Brief, the Company is seeking to align East Bend's depreciable life with its expected service life of 2035.[28]

Even as the Company plans for a 2035 retirement date, 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.[29] 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.[30] 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.[31] Recent maintenance work at East Bend occurred in the fall of 2022, which included maintenance on the station's boiler, FGD system, and coal-handling equipment.[32]

b. Woodsdale Generating Station

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.[33] Woodsdale was designed to provide peaking service and to have black start and dual fuel

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[26] *Id.* at p. 11.
[27] *Id.*
[28] *Id.*
[29] *Id.* at p. 4.
[30] *Id.*
[31] *Id.*
[32] *Id.* at p. 5.
[33] *Id.* at p. 7.

capability.[34] Woodsdale is connected to the Texas Eastern Transmission Company interstate pipeline that transports natural gas to supply the station.[35] 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.[36]

The Company follows periodic maintenance cycles for Woodsdale similar to those of East Bend.[37] Since the 2019 Rate Case, the Company has made necessary investments to ensure the reliability of Woodsdale through its useful life, including generator field rewinds, a turbine section replacement, and a generator rotor rewind.[38]

Similar to East Bend, the Company has determined that Woodsdale's depreciable life no longer aligns with its previously expected service life.[39] The original calculations of the useful life of Woodsdale assumed that the asset would retire in 2032, but based upon the actual performance of the Woodsdale units, their regular maintenance, and the fact that these units provide peaking service, updated calculations suggest that Woodsdale will be able to remain in service through 2040.[40] The Company is therefore seeking to align Woodsdale's depreciable life with an anticipated retirement date of 2040.[41]

c. Solar Generating Facilities

Duke Energy Kentucky owns three solar facilities: Walton 1 Solar Plant, located in Walton, Kentucky; Walton 2 Solar Plant, also located in Walton, Kentucky: and Crittenden Solar Plant,

[34] *Id.*
[35] *Id.* at p. 8.
[36] *Id.*
[37] *Id.* at p. 9.
[38] *Id.*
[39] *Id.* at p. 13.
[40] *Id.*
[41] *Id.*

located in Dry Ridge, Kentucky.[42] These three plants combined provide 2.8 MW of firm summer capacity, and each began commercial operation in December 2017.[43]

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.[44] 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 Company cannot immediately perform all necessary decommissioning work.[45] Activities completed or commenced since the 2019 Rate Case include removal of all asbestos-containing material (ACM) from the generating unit ductwork and facilities, a chimney condition assessment, and minor maintenance and repairs.[46]

e. Transmission Facilities

Duke Energy Kentucky owns, operates, and maintains approximately 126 miles of transmission lines operating at 69 kV.[47] All higher voltage lines to which Duke Energy Kentucky connects are part of the bulk transmission facilities owned by Duke Energy Ohio.[48] The Duke Energy Kentucky electric system is interconnected with East Kentucky Power Cooperative, Inc. via a 69-kV tie line at the Kenton substation.[49]

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[42] *Id.* at p. 9.
[43] *Id.*
[44] *Id.* at p. 10.
[45] *Id.*
[46] *Id.*
[47] Nick J. Melillo Direct Testimony (Melillo Direct), p. 3 (Dec. 1, 2022).
[48] *Id.*
[49] *Id.*

f. Distribution Facilities

The Company's distribution system is comprised of approximately 2,228 miles of primary distribution lines operating at 34.5 kV or lower and approximately 814 miles of secondary distribution circuits operating at 480 volts or below.[50] The delivery system also includes approximately 39 combined transmission and distribution substations with a combined capacity of approximately 3,433,000 kV and various other equipment and facilities.[51] The Company achieved positive customer reliability scores that exceeded the industry average in calendar year 2021.[52]

Duke Energy Kentucky is making substantial investments in its distribution system. In the 2019 Rate Case, Duke Energy Kentucky's forecasted cost of electric delivery system plant-in-service was $581,657,991 (thirteen-month average forecasted balance ending March 31, 2021).[53] However, as of March 31, 2021, Duke Energy Kentucky's actual cost of electric delivery system plant-in-service was $597,672,897.[54] The Company's forecasted test year (thirteen-month average balance ending June 30, 2024) in this case is projected to be $697,001,290.[55] While load growth across the entire Duke Energy Kentucky system has not changed significantly, localized growth has had a significant impact upon the Company and is driving the current and near-term investments.[56] Maintaining reliability, particularly as older equipment requires replacement, also accounts for a significant portion of these investments.[57]

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[50] *Id.*
[51] *Id.*
[52] *Id.* at p. 15.
[53] *Id.* at p. 4.
[54] *Id.*
[55] *Id.*
[56] *Id.* at pp. 5–6.
[57] *Id.* at p. 6.

3. Community Involvement

Duke Energy Kentucky prides itself on its high level of community engagement and development. In 2021, Site Selection Magazine named Duke Energy to its Top 10 Utilities in Site Selection for North America for the twentieth consecutive year.[58] Since 2011, Duke Energy's Urban Revitalization Initiative has provided over $3.2 million to one hundred (100) projects in the Duke Energy Kentucky and Duke Energy Ohio service areas for urban redevelopment projects in the urban core that spur commercial redevelopment and job creation.[59] Approximately half of that funding has gone to projects in Northern Kentucky.[60]

Additionally, the Company's active participation in over a dozen local economic development, education, and community-minded organizations has helped generate over 35,000 jobs and $5.2 billion of capital investment in Northern Kentucky since 2006.[61] Since 2016, Duke Energy Kentucky and the Duke Energy Foundation have contributed over $4 million in shareholder dollars to charitable organizations in Kentucky.[62] 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 17,000 hours of their time.[63]

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

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[58] Spiller Direct, p. 9.
[59] *Id.* at p. 10.
[60] *Id.*
[61] *Id.*
[62] *Id.* at p. 12.
[63] *Id.*

convenient.[64] The Company uses three different resources to stay informed as to overall customer satisfaction: the Customer Experience Monitor survey (CX Monitor Survey), the annual J.D. Power Electric Utility Residential Customer Satisfaction Study (J.D. Power Study), and Fastrack, Duke Energy's proprietary post-transaction customer satisfaction measurement tool.[65] The results have been consistently good, and indeed, have improved over time.[66]

As of April 2022, the Company implemented Customer Connect, a modern customer information system (CIS) that provides customers with key benefits and improves customers' overall experience with the Company.[67] Transition to and deployment of Customer Connect was smooth, with the Company far exceeding industry benchmarks for post-implementation billing metrics.[68] Nonetheless, the Company increased its customer service staffing in the weeks leading up to and following Customer Connect's deployment to ensure a smooth transition for customers.[69]

5. Developments Since the 2019 Rate Case

Since its 2019 Rate Case, Duke Energy Kentucky has continued to make prudent operational decisions and investments in its electric generation and delivery system. For instance, Duke Energy Kentucky has invested nearly $300 million in additional electric infrastructure to enhance the safety, reliability, and resiliency of its electric system and to support localized economic development through adequate infrastructure and capacity in areas where growth is occurring.[70] Duke Energy Kentucky is experiencing significant development in specific areas of

[64] *See id.* at pp. 13–19 (describing opportunities available to customers to engage with the Company and manage their bills).
[65] *Id.* at p. 19.
[66] *See id.* at pp. 20–23.
[67] Retha I. Hunsicker Direct Testimony (Hunsicker Direct), p. 4 (Dec. 1, 2022).
[68] *Id.* at pp. 6–8.
[69] *Id.* at p. 8.
[70] Spiller Direct, pp. 23–24.

its Northern Kentucky service territory, and additional capacity and facilities are necessary to provide safe, reliable, and adequate service to those areas.[71]

Looking forward, the Company is exploring strategies to improve its service and electric delivery system. The Company continues to evaluate opportunities to invest in new technologies provided to customers, including the new CIS, programs designed to support development of EV charging infrastructure, and a subscription-based solar development program for customers desiring to directly invest in renewable energy.[72] These developments are discussed in detail in this Brief and are supported by the administrative record in this case.

B. Procedural History

Duke Energy Kentucky filed its Notice of Intent to File an Application for the Adjustment of Electric Rates on November 1, 2022. The Application was filed on December 1, 2022. The Commission issued a Deficiency Letter on December 6, 2022, to which the Company responded on December 8, 2022. While the Commission entered an Order on December 13, 2022 rejecting the Company's filing due to the errors noted in the Deficiency Letter, the Commission issued a Suspension Order on December 19, 2022 after finding that the Company had cured all Application filing deficiencies. Proof of publication of customer notice was filed on January 30, 2023.

The Office of the Attorney General (OAG) and Sierra Club each filed a motion to intervene in the case on December 5, 2022 and December 21, 2022, respectively. Walmart Inc. (Walmart), The Kroger Co. (Kroger), and Kentucky Broadband and Cable Association (KBCA) each filed a similar motion on January 3, 2023. The Commission granted OAG's motion on December 13,

[71] *Id.* at p. 24.
[72] *Id.*

2022; Sierra Club's motion on January 6, 2023; and each of Walmart's, Kroger's, and KBCA's motions on January 17, 2023.[73]

On March 23, 2023, the Commission issued an Order setting a formal hearing on Duke Energy Kentucky's Application to commence on May 9, 2023. 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 3, 2023. A formal hearing was held from May 9 through May 11, at the Commission's offices in Frankfort, Kentucky. In all, thirty-one witnesses took the stand on behalf of Duke Energy Kentucky, and seven cumulative witnesses testified on behalf of the Intervenors. Following the hearing, Duke Energy Kentucky responded to additional Post-Hearing Requests for Information from Commission Staff, KBCA, and OAG.

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.[74] It is firmly established that "the regulation of public utilities has and does serve a public purpose. It has a substantial relation to the public welfare, safety and health and, in a real degree, promotes these objects."[75] The Commission is a creature of statute and has only such powers granted to it by the General Assembly.[76] The Commission's jurisdiction is therefore limited to the "rates" and "services" of the Company.[77] The

[73] OAG, Sierra Club, Walmart, Kroger, and KBCA are each referred to herein as an "Intervenor."
[74] Application of Duke Energy Kentucky, Inc. (Application), p. 2 (Dec. 1, 2022).
[75] *City of Florence v. Owen Elec. Co-op., Inc.*, 832 S.W.2d 876, 882 (Ky. 1992).
[76] *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).
[77] *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,*

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."[78] 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."[79] In undertaking this purpose, the Commission is affecting the natural property rights of Duke Energy Kentucky.[80] Accordingly, the principles of due process, equal protection and other rights and guarantees afforded under the Constitutions of the United States of America and the Commonwealth of Kentucky apply with full force and effect.[81] The Commission "has no authority to impose a new duty on utilities when that duty has no foundation in law. To do so is an unconstitutional legislative act by the [Commission]."[82]

The Commission's statutory mandates therefore provide "an integrated, comprehensive system aimed at providing stability and notice to all entities involved in the rate process."[83] In undertaking this process, "the Commission has discretion in working out the balance of interests necessarily involved and . . . it is not the method, but the result, which must be reasonable."[84]

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165 S.W.2d 567 (Ky. 1942).

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

[79] *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)).

[80] *See Bobinchuck v. Levitch,* 380 S.W.2d 233, 236 (Ky. 1964). In contrast, the right to receive utility service is merely a right that may be conferred by statute and lacks the same fundamental constitutional protections. *See Smith v. Southern Bell Tel. & Tel. Co.,* 104 S.W.2d 961, 964 (Ky. 1937).

[81] *See Kentucky Indus. Utility Customers, Inc. v. Kentucky Utilities Co.*, 983 S.W.2d 493, 497 (Ky. 1998).

[82] *Jackson Cnty. Rural Elec. Co-op*, 50 S.W.3d at 766.

[83] *Cincinnati Bell,* 223 S.W.3d at 837–38 (citing KRS 278.160, 278.180, 278.190, 278.260, 278.270, and 278.390).

[84] *Kentucky Indus. Utility Customers*, 983 S.W.2d at 498 (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)).

Kentucky's highest court has noted that "the task of the [Commission] Staff is to conduct investigations to facilitate a thorough exploration of the interests and issues involved. The traditional role of the Staff is 'generally to analyze the evidence and advise the Commission.'"[85] 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.[86]

However, the Commission ultimately must approve rates that are "fair, just and reasonable."[87] 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."[88] By contrast, an unreasonable rate "has been construed in a rate-making sense to be the equivalent of confiscatory."[89] 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 increase the costs of Company borrowing on

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[85] *Kentucky American Water Co. v. Com. ex rel. Cowan,* 847 S.W.2d 737, 740 (Ky. 1993) (internal citations omitted).
[86] *National-Southwire Aluminum Co.*, 785 S.W.2d at 512.
[87] KRS 278.030(1).
[88] *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 (1976)).
[89] *Public Service Comm'n of Kentucky v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986).

behalf of customers.[90] It is critically important for Duke Energy Kentucky to obtain reasonable, supportive credit metrics to maintain strong credit quality.[91] As the Applicant, the Company bears the burden of proof.[92]

B. Duke Energy Kentucky's Proposed Increase in Base Rates

Duke Energy Kentucky's increase in base rates proposed 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 March 31, 2021, were ultimately authorized by this Commission by Order dated April 27, 2020,[93] and as amended on rehearing by Order dated October 16, 2020, in Case No. 2019-00271.[94] Company witness Mr. Christopher Bauer summarizes the necessity of the Company to have suitable rates:

> Financial strength and access to capital are necessary for Duke Energy Kentucky to provide cost-effective, safe, and reliable service to its customers. Specific targets that support financial strength and flexibility include: 1) maintaining an equity component of the capital structure that is supportive of Duke Energy Kentucky's credit quality; 2) ensuring timely recovery of prudently incurred costs; 3) maintaining sufficient cash flows to meet obligations; and 4) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the Company and its customers, and each of these targets help the Company meet its overall financial objectives.[95]

The Company's capital requirement is projected to be approximately $885 million from 2023 through 2025, with approximately $715 million devoted to projected capital expenditures

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[90] *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)).
[91] *See generally* Christopher R. Bauer Direct Testimony (Bauer Direct) (Dec. 1, 2022).
[92] *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)).
[93] *See 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. 2019-00271, Order (April 27, 2020).
[94] *See id.*, Rehearing Order (October 16, 2020).
[95] Bauer Direct, p. 3.

and approximately $170 million in debt maturities.[96] Indeed, net rate base has grown by approximately $300 million since the time of the 2019 Rate Case.[97] This, in part, has resulted in major increases in depreciation expense and the cost of capital, which are the primary reasons that Duke Energy Kentucky is seeking an increase in base rates.[98]

Despite these upward pressures on rates, Duke Energy Kentucky has consistently controlled costs and has continued to make only prudent investments in the interests of its customers.[99] As described in further detail below, the Company's requested increase in base rates is reasonable and amply supported by record evidence in this proceeding.

1. Base Period and Forecasted Test Year Expenses

The Company utilized a base period ending February 28, 2023, which consists of six months of actual data from March 1, 2022 through August 31, 2022, and six months of budgeted data from September 1, 2022 through February 28, 2023.[100] The Company also used a fully forecasted test period spanning the twelve-month period ending on June 30, 2024.[101] The forecasted test year data was developed by using the Company's standard forecasting methods.[102] In accordance with KRS 278.192(2)(b), the Company filed its updated base period data on April 14, 2023. 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,[103] the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by the Company's management.[104]

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[96] *Id.* at p. 19.
[97] Lawler Direct, p. 4.
[98] *Id.* at pp. 4–7.
[99] *See* Spiller Direct, p. 23; Lawler Direct, p. 23.
[100] Grady "Tripp" S. Carpenter Direct Testimony (Carpenter Direct), p. 3 (Dec. 1, 2022).
[101] *Id.*
[102] *See id.* at pp. 3–13 (describing the Company's standard forecasting methodology in significant detail).
[103] 807 KAR 5:001, Section 16(7)(e)(2).
[104] Carpenter Direct, p. 13.

2. Rate Base

a. Revenue Lag Days in Cash Working Capital

The Company conducted a lead-lag study as part of this case, which is an analysis generally designed to determine the funding required to operate the Company on a day-to-day basis.[105] A lead-lag study compares (1) the timing difference between the receipt of services by customers and their subsequent payment for these same services and (2) the timing difference between the incurrence of costs by a company and its subsequent payment of these costs. As a result, a lead-lag study computes both a revenue (lead) or lag and an expense (lead) or lag.[106]

Because Duke Energy Kentucky's electric customers receive service prior to paying for it, Duke Energy Kentucky experiences a revenue lag in its daily operations.[107] Revenue lag days consist of four components, one of which is collection lag.[108] Collection lag identifies the time delay between the posting of customer bills to accounts receivable and the receipt of these billed revenues; it begins with the posting of bills and ends with the receipt of payment.[109] The lead-lag study conducted by the Company in this case shows that the Company waits an average of 27.02 days from the date of customer billing to the date it receives cash payment for service (*i.e.*, 27.02 collection lag days).[110]

OAG witness Mr. Lane Kollen recommends that the Company's collection lag days be reduced to 1.46 days claiming that the "Company sells the prior day's customer accounts receivables on a daily basis to an affiliate financing entity, Cinergy Receivables Company, LLC ("CRC") . . . to accelerate the Company's conversion of receivables into cash on a daily basis

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[105] Paul M. Normand Direct Testimony (Normand Direct), p. 3 (Dec. 1, 2022).
[106] *Id.*
[107] *Id.*
[108] *Id.* at p. 8.
[109] *Id.* at p. 9.
[110] Paul M. Normand Rebuttal Testimony (Normand Rebuttal), pp. 3–4 (April 14, 2023).

rather than waiting until customers actually pay their bills."[111] The Commission should decline to adopt OAG's recommendation because this recommendation is based on an inaccurate understanding and representation of the relationship between Duke Energy Kentucky and Cinergy Receivables Company (CRC). Specifically, this recommendation ignores the fact that, notwithstanding its relationship with CRC, Duke Energy Kentucky only receives cash for its customer accounts receivables after its customers remit payment to the Company.[112]

The fact that the Company participates in a receivables financing program with a special purpose entity, CRC, does not justify OAG's recommendation. The specific financing program used by the Company is typically referred to as securitization financing, which is the financing of accounts receivable to efficiently diversify the long-term debt raised by an entity at reasonable interest rates.[113] In this case, the relevant collection of accounts receivable belong to the Company, and additionally belong to Duke Energy Indiana, LLC (Duke Energy Indiana) and Duke Energy Ohio, Inc. (Duke Energy Ohio) for scale of borrowing and efficiency of administration of the securitization financing mechanism.[114] These receivables are legally transferred daily from the three utilities noted above, including Duke Energy Kentucky, to CRC, and CRC then uses those receivables as collateral for borrowings under a credit facility that currently has a maximum borrowing amount of $350 million.[115]

While amounts borrowed under the credit facility are reflected on Duke Energy's Consolidated Balance Sheets as Long-Term Debt, they are not reflected on the Consolidated Balance Sheets of Duke Energy Kentucky, Duke Energy Indiana, and Duke Energy Ohio due to

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[111] Lane Kollen Direct Testimony (Kollen Direct), p. 11 (Mar. 10, 2023).
[112] Normand Rebuttal, p. 3.
[113] Thomas J. Heath, Jr. Rebuttal Testimony (Heath Rebuttal), p. 4 (April 14, 2023).
[114] *Id.* at pp. 4–5.
[115] *Id.* at pp. 5–6.

technical Generally Accepted Accounting Principles (GAAP) consolidation accounting guidance.[116] However, Duke Energy Kentucky includes its pro rata share (approximately $35.0 million) of the outstanding debt of CRC in its embedded cost of debt for ratemaking purposes.[117] Any adjustment to collection lag days for this securitization financing without a related adjusted to the embedded cost of debt would therefore result in asymmetrical treatment of the financing program in this case.[118]

More importantly, there is no transfer of funds between CRC and Duke Energy Kentucky, Duke Energy Ohio, or Duke Energy Indiana immediately upon customer billings;[119] the Company only receives cash when the receivables are paid by customers.[120] On a daily basis, Duke Energy Kentucky, Duke Energy Ohio, and Duke Energy Indiana receive cash from their customers when bills are paid by those customers.[121] These three utilities continue to process customer billings and receive cash from customers for payment of their bills, which are received in collection accounts in the name of CRC that are reflected on the utilities' balance sheets.[122] As shown in the Company's lead lag study, the time between when a customer is billed and the receipt of cash from the customer by Duke Energy Kentucky is 27.02 days.[123] Cash in these accounts is then moved daily into general concentration accounts, in which the lenders of CRC's credit facility have a security interest.[124] The only cash changing hands between the Company and CRC occurs monthly when the Company, along with Duke Energy Indiana and Duke Energy Ohio, pays interest on its

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[116] *Id.* at p. 6.
[117] *Id.*
[118] *Id.* (discussing the asymmetry in OAG witness Kollen's treatment of this arrangement in collection lag days).
[119] *Id.* at p. 8.
[120] *Id.* at p. 10.
[121] *Id.* at p. 7.
[122] *Id.* at pp. 7–8.
[123] Normand Rebuttal, p. 4.
[124] Heath Rebuttal at p. 8.

pro rata share of CRC's outstanding debt.[125] There is no cycle of cash flowing between CRC and the Company related to the value of the accounts receivables, whether daily or otherwise.

The securitization financing structure that the Company has in place with CRC benefits ratepayers in a number of ways. This arrangement allows the Company to take advantage of reasonable cost debt from a diversified lender base such that the Company's need to raise additional money in the private placement market is limited.[126] Further, interest rates on this kind of debt have historically been lower compared to other instruments,[127] which benefits consumers in the form of lower base utility rates.

Notably, this securitization financing arrangement with CRC also does not affect revenue lag.[128] The Company does not receive any cash from CRC upon its daily transfer of receivables, as described above; thus, revenue lag is unaffected, as is collection lag. Collection lag days should therefore remain at 27.02, not 1.46 days as recommended by OAG.[129]

b. Fuel and Limestone Inventories and Vendor Financing

Fuel and limestone (or lime) inventories are additions to rate base as other working capital.[130] The Company does not finance its purchases of fuel and lime from the date it purchases the fuel and lime from its vendors until it actually pays those vendors; instead, the vendors finance these purchases for this short period of time.[131] This concept is sometimes referred to as "zero-cost vendor financing."[132]

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[125] *Id.* at p. 7.
[126] *Id.* at p. 9; Heath Cross, HVR 6:01:42 (May 10, 2023).
[127] Heath Cross, HVR 6:01:42 (May 10, 2023).
[128] Normand Direct, p. 4.
[129] *See generally* Heath Rebuttal, pp. 4–10 (explaining how the securitization financing arrangement described in this Brief does not affect the calculated revenue lag days of 27.02, and as a result, that OAG witness Kollen's recommendation that the revenue lag days be considered 1.46 is incorrect).
[130] Steinkuhl Revised Rebuttal, p. 5.
[131] *Id.* at p. 6.
[132] *See, e.g.*, Kollen Direct, p. 9.

In his Direct Testimony, OAG witness Mr. Kollen recommended that the Company adjust its fuel and limestone balances in rate base to reflect this financing arrangement.[133] The Company agreed to this adjustment in rebuttal testimony, as this adjustment is supported by prior Commission decisions.[134] This adjustment results in a reduction in rate base of $6.459 million, and a reduction in the requested revenue requirement of $0.604 million, which is reflected in the Company's revised revenue requirement supported by Company witness Ms. Lisa Steinkuhl.[135]

3. Operating Income Adjustments

a. Amortization Period and Recovery of Planned Generation Outage Expense as Regulatory Asset

The Company requests to amortize and recover the planned generation maintenance outage expense regulatory asset in this proceeding.[136] The Commission authorized the Company to begin deferring annual expenses for planned outage operations and maintenance (O&M) above or below the amount being recovered in base rates in Case No. 2017-00321.[137] This deferral is based on the annual amount of planned outage O&M incurred compared to the annual amount included in base rates.[138] Because the actual expenses incurred year to date as of June 30, 2022 were not over the annual amount included in base rates, no deferrals were booked as of June 30, 2022.[139] Therefore, the December 31, 2021 balance of $8,309,265 is being proposed for amortization and recovery in this case.[140] The Company proposes amortizing this expense regulatory asset balance over a five-year period.[141]

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[133] *See id.* at pp. 8–11.
[134] *See id.* at p. 6 (citing Case Nos. 2020-00174 and 2021-00214).
[135] Steinkuhl Revised Rebuttal, at pp. 6–7.
[136] Lisa D. Steinkuhl Direct Testimony (Steinkuhl Direct), p. 17 (Dec. 1, 2022).
[137] *Id.*
[138] *Id.*
[139] *Id.*
[140] *Id.* at p. 18.
[141] *Id.* at p. 17.

There is ample justification for amortization and recovery of these costs in the record in this case, including actual monthly outage expense data provided by unit from 2018 through 2021.[142] Further, these expenses were incurred reasonably and prudently by the Company as costs to operate and manage its generation assets through their useful lives. For example, in spring of 2021, the Company performed an eight-week outage at East Bend to perform significant maintenance to the station's turbine, generator, boiler, and FGD.[143] This included a complete rewind of the Generator Stator, significant maintenance of boiler fuel, steam, and water components, main low-pressure turbine blade evaluation, and FGD absorber module inlet nozzle refurbishment.[144] The Company also conducted a similar five-week outage at East Bend in fall of 2022.[145] Scheduled maintenance intervals are based on industry standards, inspections, operating experience, and OEM guidance.[146] The scope of the maintenance performed at East Bend during these planned outages is part of the Company's investment strategy to sustain reliability and long-term operation of generating assets through their useful lives.[147] This maintenance was also performed in accordance with industry best practices, as indicated above.[148]

These kinds of investments and outages are necessary to continue safe and reliable operation of the Company's generating units.[149] Failure to incur these costs and perform this maintenance would negatively impact unit performance metrics and generation reliability factors, making the unit potentially unavailable for the generation needs of the Company's customers.[150]

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[142] *See* AG-DR-01-100b, Attachment 2.
[143] Luke Direct, p. 5; William Luke Rebuttal Testimony (Luke Rebuttal), p. 5 (April 14, 2023).
[144] Luke Direct, p. 5; Luke Rebuttal, pp. 5–6.
[145] Luke Direct, p. 5; Luke Rebuttal, p. 6.
[146] Luke Rebuttal, at p. 7.
[147] *Id.* at p. 6; *see also* AG-01-100(c)–(f) (listing and describing all outages performed).
[148] *Id*. at p. 7.
[149] *Id.*
[150] *Id.* at p. 8.

The risk of forced outages would also increase, and increased forced outage rates would result in increased response costs compared to planned outages:

> [F]orced outages tend to cost more than planned outages because forced outages occur when the unit is running, causing substitute power requirements. Moreover, absent proper planning, performing routine and recommended maintenance and making necessary capital investments and replacement, the risk of forced outages increases, and the likelihood of more significant damage occurs. Forced outages likely increase overall repair costs as compared to performing the maintenance on a planned, more efficient manner.[151]

Proper execution of planned outages also prepares the units for more reliable performance during unplanned, extraordinary weather events such as Winter Storm Elliott, which occurred in December 2022.[152] The Company's planned outage expense was simply a necessary investment in the long-term reliability of its generating assets, and indeed was prudently incurred. The requested amortization and recovery is therefore appropriate.

Further, the regulatory asset balance proposed for recovery is reasonable, as the balance will not necessarily zero out over the amortization period due to its dependence on the type of planned outage work necessary to maintain the unit's reliability.[153] Indeed, "[t]he Company's actual planned outage maintenance expense varies from year [to year] due to the scope and frequency of the actual outage activities."[154] Recently, outage costs are on the rise due to supply chain constraints, and particularly for an asset the age of East Bend, where replacement components and skilled labor qualified for this type of asset are becoming ever scarcer.[155]

The Company's planned outage expense proposed for amortization and recovery in this case should be approved, as this expense was incurred prudently and reasonably and was necessary

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[151] *Id.*
[152] *Id.*
[153] *Id.* at p. 9.
[154] Kollen Direct, p. 18.
[155] Luke Rebuttal, p. 9.

to maintain the reliability and safety of the Company's generating units. However, if the Commission disallows amortization at this time, the Company requests that the Commission approve the balance of the regulatory asset or liability to accrue a carrying cost at the Company's long-term debt rate approved in this proceeding.[156] In this instance, the Company would request that the carrying costs apply to any credit or to any debit balance to maintain the symmetry and ensure that neither customers nor the Company are deprived of the time value of money.[157] Additionally, while the Company believes that a five-year amortization period is appropriate in this case to recover these costs in a manner that reasonably matches the timing of the costs' accrual with the time of their recovery, the Company requests that if the Commission orders the Company to amortize its cost over a different and greater period, that it allow the Company to accrue carrying costs at its long-term debt rate approved in this proceeding.[158]

b. Amortization Period and Recovery of Forced Outage Purchased Power Expense as Regulatory Asset

The Company also requests to amortize and recover the force outage purchased power expense regulatory asset in this proceeding.[159] The Commission authorized the Company to begin deferring annual expenses for replacement power expense not recovered in the FAC above or below the amounts being recovered in base rates in Case No. 2017-00321.[160] This deferral is based on the annual amount of expenses incurred for forced outage replacement power not recovered in the FAC compared to the annual amount included in base rates.[161] Because the actual expenses incurred year to date as of June 30, 2022 were over the annual amount included in base rates, there

[156] Steinkuhl Revised Rebuttal, p. 13.
[157] *Id.*
[158] *Id.*
[159] Steinkuhl Direct, p. 17.
[160] *Id.*
[161] *Id.* at p. 18.

were deferrals booked as of June 30, 2022.[162] Therefore, the June 30, 2022 balance of $1,819,460 is being proposed for amortization and recovery in this case.[163] The Company proposes amortizing this expense regulatory asset balance over a five-year period.[164]

The record is replete with evidence showing that the expense incurred by the Company related to forced outage purchased power has been prudent, reasonable, and necessary. First and foremost, the Company conducts planned and maintenance outages to minimize the number of forced outages on its generating assets.[165] According to PJM Interconnection LLC (PJM) and other market metrics, the Company's generating units are reliable.[166] The Company's planned outages support this reliability. The Company also conducts proactive maintenance outages as needed when station personnel have reason to believe a particular piece of equipment is nearing a failure.[167] These maintenance outages reduce the likelihood of a forced outage occurring in the future.[168] In the event that a forced outage does occur, the Company evaluates the best available options to return generation to customers, which includes determining the scope of a potential repair and how forecast PJM energy prices compare to the incremental expense associated with unit repair.[169] This involves extensive communication between plant and dispatch personnel.[170]

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162 *Id.*
163 *Id.*
164 *Id.* at p. 17.
165 John D. Swez Rebuttal Testimony (Swez Rebuttal), p. 2 (April 14, 2023).
166 *Id.* at p. 3.
167 *Id.* at p. 8.
168 *Id.*
169 *See id.* at p. 2 ("If PJM energy prices are forecast to be equal to or less than the variable and startup cost of the generating unit in question and if the potential for a PJM capacity performance event is low, it may make economic sense to choose a lesser cost, but longer in duration repair alternative, than a more expensive and quicker solution to return the unit to service. Conversely, if PJM energy prices are forecast to be greater than the variable and startup cost of the generating unit in question, or if the potential for a PJM capacity performance event is high, it will likely make economic sense to spend additional costs to return the unit to service quicker. Note that under both scenarios, the risk of a potential change to the forecasted market prices may need to be additionally considered.").
170 *Id.* at p. 3

Currently, replacement power that the Company purchases from the PJM market in the wake of forced outage events is one of the primary costs associated with forced outage events.[171] PJM power prices have shown significant volatility since 2020, as have coal and natural gas markets during mid-2021 through 2022.[172] Because natural gas is frequently the marginal fuel within PJM, it has a strong correlation to PJM power prices.[173] All of these factors have driven the Company's increased replacement power costs due to forced outages since the 2019 Rate Case.[174]

Thus, it is in both the Company's and its customers' best interests to minimize forced outages and avoid the volatility and unpredictability in purchasing power from energy markets to the extent possible. The Company has a financial incentive to increase generating unit availability—and therefore minimize forced outages—through the Profit Sharing Mechanism (PSM), whereby it shares 90 percent of off-system margins with customers and conversely keeps 10 percent of off-system margins.[175] The Company would also bear 10 percent of assessment of any PJM capacity performance penalties assessed in the future, which creates a further incentive to reduce forced outages.[176]

Recent events show that the Company's investments made to mitigate forced outages have done just that. For instance, data related to the Winter Storm Elliott and the related PJM Capacity Performance event that occurred in December of 2022 suggest that the Company will receive net PJM Capacity Performance payments of approximately $1,000,000.[177]

The Company's forced outage purchased power expense proposed for amortization and recovery in this case should be approved, as the evidence summarized above suggests that this

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[171] *Id.* at pp. 4, 5.
[172] *Id.* at p. 6. Coal and natural gas markets have also exhibit higher prices during this timeframe. *Id.*
[173] *Id.* at p. 7.
[174] *Id.* at pp. 5–6.
[175] *Id.* at p. 10.
[176] *Id.*
[177] *Id.* at p. 9.

expense was incurred prudently and reasonably and was necessary to maintain the reliability and safety of the Company's generating units. The Commission has the experience, expertise, and authority to rule on this issue in this proceeding, and need not wait until Case No. 2022-00190 has a final order, [178] as OAG witness Kollen suggests.[179] This argument is also inconsistent with other positions taken by OAG witness Kollen in this case: for instance, Mr. Kollen argues in favor of the Company's recommendation to eliminate volatility in Rider FAC by introducing a twelve-month rolling average calculation, but the Commission is presently addressing the volatility of fuel expense in the same case cited by Mr. Kollen, Case No. 2022-00190.[180]

However, if the Commission disallows amortization at this time, the Company requests that the Commission approve the balance of the regulatory asset or liability to accrue a carrying cost at the Company's long-term debt rate approved in this proceeding.[181] In this instance, the Company would request that the carrying costs apply to any credit or to any debit balance to maintain the symmetry and ensure that neither customers nor the Company are deprived of the time value of money.[182] Additionally, while the Company believes that a five-year amortization period is appropriate in this case to recover these costs in a manner that reasonably matches the timing of the accrual of the costs with the time of their recovery, the Company requests that if the Commission orders the Company to amortize its cost over a different and greater period, that it allow the Company to accrue carrying costs at its long-term debt rate approved in this proceeding.[183]

[178] Steinkuhl Revised Rebuttal, p. 16.
[179] *See* Kollen Direct, p. 23.
[180] *See id.* at pp. 5–6.
[181] Steinkuhl Revised Rebuttal, p. 15.
[182] *Id.*
[183] *Id.*

c. Amortization Period of East Bend Deferred O&M Expense

The Company has included in its base revenue requirement $4.498 million for recovery of the East Bend deferred O&M expense regulatory asset.[184] In Case No. 2014-00201, the Commission previously authorized the Company to defer incremental East Bend O&M expense to a regulatory asset from the date it acquired the remaining ownership of East Bend until the O&M expense was included in and recovered through base rates.[185] In Case No. 2017-00321, the Commission subsequently authorized recovery of the East Bend deferred O&M expense regulatory asset over ten years.[186]

While OAG witness Kollen recommends that the Commission now extend the amortization period and recalculate the levelized recovery to reflect a probable retirement date of mid-year 2041, Mr. Kollen notably recommended a ten-year amortization period for this regulatory asset in Case No. 2017-00321.[187] The Commission's order in that case found that the ten-year amortization period, as proposed by the Company and supported by Mr. Kollen, was "reasonable and should be approved."[188] Mr. Kollen's recommendation here is therefore an untimely request for the Commission to reconsider its final decision in a case from a number of years ago, and in any event, is not supported by substantive evidence. The Commission should uphold its prior decision here.

d. Amortization Period of Coal Ash Asset Retirement Obligations (ARO) included in Environmental Surcharge Mechanism (Rider ESM)

The Company presently recovers the East Bend coal ash ARO regulatory asset through Rider ESM on a levelized basis over ten years.[189] Recovery of this regulatory asset began in 2018

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[184] Kollen Direct, p. 24.
[185] *Id.*
[186] *Id.*
[187] Steinkuhl Revised Rebuttal, p. 17.
[188] *Id.*
[189] Kollen Direct, p. 44.

and is set to complete in 2028.[190] As explained above, the Commission has already addressed this issue, and indeed approved the ten-year amortization period of this regulatory asset in Case No. 2017-00321.[191] Specifically, the Commission found that the Company should "amortize only the actual balance of the East Bend Coal Ash ARO regulatory asset over 10 years and recover additional costs associated with the settlement of the East Bend Coal Ash ARO in the second month after they are incurred."[192] The Company has been employing this methodology since it was authorized to do so by the Commission.[193] Mr. Kollen's recommendation here is also an untimely request for the Commission to reconsider its prior decision. As such, the Commission should uphold its prior decision in this case.

e. 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 has two primary objections to the development of terminal net salvage estimates in this case. First, OAG claims that decommissioning, should be excluded from the depreciation rate and instead be a standalone expense.[194] Second, OAG asserts that the escalation of decommissioning costs to the date of retirement should be reduced to just the test year.[195] Neither of these claims are correct, and OAG provides no evidence to support their merit.

The Company's current depreciation rates approved by the Commission in previous depreciation studies include decommissioning costs as part of terminal net salvage that are

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[190] *Id.*
[191] Steinkuhl Revised Rebuttal, p. 18.
[192] *Id.*
[193] *Id.*
[194] Kollen Direct p. 5.
[195] *Id.*

escalated to the date of retirement and were developed in the same manner as in the instant case.[196]

The Commission approved the Company's proposals with regard to terminal net salvage:

> The Commission finds Dukes 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.[197]

It is widely accepted that depreciation should include future decommissioning costs as part of 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.[198] This applies not only to decommissioning costs, but also to the costs of all plant assets.[199] Because net salvage must be based on future costs, decommissioning costs for net salvage must also be estimates of the future cost at the time of decommissioning.[200] 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.[201] In order to recover the service value of the Company's assets, net salvage must be determined at the cost that will be incurred in the future.[202] 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.[203]

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[196] John J. Spanos Rebuttal Testimony (Spanos Rebuttal), p. 5 (April 14, 2023).
[197] *Electronic Application of Duke Energy Kentucky, Inc. for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief*, Case No. 2017-00321, Order, p. 27.
[198] Spanos Rebuttal, p. 6.
[199] *Id.*
[200] *Id.* p.7.
[201] *Id.*
[202] *Id.*
[203] *Id.*

By definition, the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) specifies that cost of removal, as part of net salvage, must be recovered through depreciation expense and is the actual amount paid at the time of the transaction. Because net salvage will occur in the future, it is an estimate of the future cost that must be included in depreciation rates.[204] As Company witness Spanos explains in his rebuttal testimony, USOA specifically defines net salvage as follows:

> 19. Net salvage value means the salvage value of property retired less the <u>cost of removal</u>.

The FERC USOA specifically defines Cost of Removal 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 (emphasis added):

> 9. Cost means the <u>amount of money actually paid</u> 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.[205]

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 (typically referred to as "NARUC") and *Depreciation*

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[204] *Id.* p. 8.
[205] *Id.*

Systems by Wolf and Fitch (Wolf and Fitch).[206] Both texts are clear that net salvage should be included in depreciation as a future cost. NARUC states the following:

> [U]nder 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 difference between the gross salvage that will be realized <u>when the asset is disposed of and the cost of retiring it</u>.[207] (Emphasis added)

NARUC 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 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 received</u>.[208] (Emphasis added)

Similarly, Wolf and Fitch explain that:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.[209]

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

Second, it is 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.[210] 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. OAG's proposal to segregate the

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[206] *Id.*
[207] *Id.* (*citing* NARUC Manual at 18).
[208] *Id.* pp. 8–9 (*citing* NARUC Manual at 18).
[209] *Id.* (*citing* Wolf and Fitch, p. 7).
[210] *Id.* p. 10

decommissioning expense and base it on a calculation performed at a single point in time (in this case, December 31, 2021) would significantly underestimate the full cost of decommissioning at the end of the facility's life. Not only does OAG'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.[211]

Finally, the Company has an additional concern with OAG'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. OAG'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 depreciation expense and cost of removal for all other asset types—distribution and transmission. Given all of these issues and concerns with the OAG'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.

f. Aligning Depreciation Expense with Useful Lives

In this case, the Company is seeking to align depreciation and decommissioning costs with probable generating asset retirement dates.[212] The Commission denied the Company's request to update its depreciation rates in the Company's 2019 Rate Case.[213] Because of that prior decision,

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[211] *Id.*
[212] Spiller Direct, p. 25; Lawler Direct, p. 4; Lisa M. Quilici Direct Testimony (Quilici Direct), p. 3 (Dec. 1, 2022).
[213] Spiller Direct, p. 25; Lawler Direct, p. 4; Quilici Direct, p. 3

the depreciation rates for the Company's East Bend Generating Station and Woodsdale Generating Station do not align with their previously estimated or currently existing useful lives, thereby creating substantial exposure for future customers to assume the costs for assets that are not used to serve them.[214] Adjusting depreciation expense and re-establishing useful lives is common and sound rate-making policy. In recent years, there is 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.[215]

The need to adjust depreciation rates is further evidenced by the fact that East Bend is projected to retire by 2035, earlier than what was contemplated in the 2019 Rate Case.[216] This earlier retirement date is influenced by developments since the 2019 Rate Case, including forecasted market prices, environmental regulations, and subsidies provided to low- and no-carbon emitting resources that have the effect of making fossil fuel generation less economic.[217] As described in further detail below, the Company needs to properly align East Bend's and Woodsdale's depreciation rates with their anticipated service lives to avoid intergenerational subsidies and protect and minimize the amount that future customers would pay for any post-retirement undepreciated plant remaining after the generating assets' retirement, as well as with their replacement resources.[218]

g. East Bend

East Bend is currently projected to retire in 2035, and the Company is seeking to align the depreciation rates and decommissioning expense for this asset with this date.[219] In the 2019 Rate

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[214] Spiller Direct, p. 25.
[215] Spanos Rebuttal, p. 4.
[216] *Id.*
[217] *Id.*
[218] *Id.* at p. 26; Quilici Direct, p. 23.
[219] Spiller Direct, p. 28; Lawler Direct, p. 5; Luke Direct, p. 11.

Case, East Bend had an assumed retirement date of 2041.[220] Due to market pressures that are impacting the service life of the generating unit, it is becoming increasingly more expensive to own, operate, and maintain the asset.[221] As a result, the Company's modeling shows that East Bend will now likely retire in 2035.[222]

Because the Company was not permitted to update depreciation rates to include changes in plant balances between the Company's 2017 and 2019 electric rate cases, there will be a significant net plant balance not yet depreciated and therefore uncollected in rates by 2041.[223] This must be corrected in this proceeding.[224] Additionally, the Company needs to align East Bend's depreciation rates with the projected retirement date of 2035, as this is necessary to minimize future customers' exposure to the unrecovered net book value of the plant at the time of its retirement.[225] Prior to 2015, the most common range of life spans for coal fired generating facilities was between 55 and 65 years. Since 2015, the average age of coal fired generating facilities has been well below 50 years.[226] East Bend will have a life span of 54 years if retired in 2035.

i Drivers of 2035 Retirement and Replacement Resources

There are a number of drivers that are negatively impacting the long-term viability of coal-fired generation and, in turn, that are driving East Bend's anticipated retirement date of 2035.[227]

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[220] Spiller Direct, p. 28.
[221] Spiller Direct, p. 28; Luke Direct, p. 11; Joshua C. Nowak Direct Testimony (Nowak Direct), p. 46 (Dec. 1, 2022).
[222] Spiller Direct, p. 28.
[223] Spiller Direct, p. 29; Lawler Direct, p. 4.
[224] *See* Lawler Direct, p. 5 ("Duke Energy Kentucky has been and must continue to make investments in [East Bend and Woodsdale] to ensure safe, reliable service to its customers. When capital investments are made to assets and their remaining useful life is not extended because of those investments, the depreciation rates must be adjusted to ensure that the total asset value is fully depreciated (less salvage) at the end of the service lives of the assets. Because this did not happen in the Company's 2019 rate case, current depreciation rates do not fully depreciate these assets by the end of their service lives.").
[225] Spiller Direct, p. 28.
[226] Spanos Rebuttal, p. 4.
[227] *Id.*; Luke Direct, p. 11.

Market prices for energy and capital costs are significant drivers in this context,[228] as is the Inflation Reduction Act of 2022 (IRA), which creates significant tax credits for qualified facilities used for generating electricity that have a low- to zero-emission rate for greenhouse gases.[229] Higher coal prices that drive down East Bend's capacity factor will also cause a host of issues that will contribute to East Bend's uneconomic performance by 2035.[230] As tens of thousands of megawatts of coal-fired generation is expected to retire over the next decade, fuel costs, environmental regulations, and the evolution of competing technologies providing lower cost capacity and energy options make early retirement of East Bend in 2035 very likely.[231]

Current modeling also supports this retirement date, as it shows that East Bend is likely to no longer provide economic value to customers by 2035. The Company's 2021 IRP, which contains extensive modeling scenarios related to the Company's generation assets and resources, including East Bend, in particular supports the 2035 retirement date.[232] The 2021 IRP scenarios

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[228] *See id.* at p. 12 ("East Bend's energy is sold through the PJM markets. As more energy providers enter the marketplace with lower energy and operations costs, East Bend is projected to be less competitive and called upon to produce energy less frequently. Likewise, as coal prices increase, plants like East Bend will become more unfavorable in the competitive market. In addition to fuel prices, as stations age, maintenance on those stations increases due to wear and tear on the aging equipment. This maintenance cost also contributes to the unfavorable position of the station in the market. Duke Energy Kentucky will attempt to mitigate this exposure to market purchases and volatility to the greatest extent possible for customers.").

[229] *See id.* at p. 12 ("While these [IRA] incentives are intended to directly support the development and deployment of zero emission resources, they have the indirect effect of impacting the economics of East Bend from a dispatch perspective."); Quilici Direct, pp. 10, 11 ("A clear aim of the Inflation Reduction Act is to support the development and expansion of non-carbon emitting energy sources and to accelerate the nation's energy transition . . . This will contribute to the retirements of carbon emitting power plants, including coal-fired generation. It is reasonable to expect that as a result coal plant retirements over the next decade could accelerate beyond the already planned levels.); Scott Park Direct Testimony (Park Direct), pp. 8–9 (Dec. 1, 2022) ("For example, the recently passed IRA initiative, which, among other things, provides subsidies for low and zero-emitting generating resources has an indirect impact of the viability of coal-fired resources. As these subsidized zero emitting resources come online, power prices will be pushed down and existing higher-cost assets will be less economic.").

[230] *Id.* at p. 8 ("Higher coal prices have and are expected to drive down the capacity factor of the East Bend 2 unit which lessens the value that the station provides to customers. Additionally, with less generation coming from Company resources, the remaining energy will come from greater market purchases. Operating a unit that runs so infrequently makes a unit less reliable to start up successfully which can increase capacity performance risk. Infrequent operations can create other operational issues such as increased cycling and equipment failures as well as staffing the station.").

[231] Quilici Direct, pp. 4, 6, 7, 9. In fact, since 2015, more than 6,000 MW of coal-fired generation has been retired in Kentucky. *Id.* at p. 9. This is the general trend in the United States in recent years. *See* Spanos Rebuttal, p. 4.

[232] Luke Direct, p. 11.

drove the development of portfolio possibilities, with the most likely result being East Bend's retirement in 2035.[233] While a number of changes have happened since submission of the 2021 IRP,[234] the impact of these changes is reasonably contained within the breadth of the scenarios presented in the IRP.[235] These factors are dynamic in nature; although they would impact the IRP analysis in isolation, a holistic evaluation of all factors supports the range of scenarios provided in the 2021 IRP, with 2035 retirement being the most likely.[236] The Company also periodically makes updates to its resource planning assumptions and runs optimized portfolio models to assess its generation options.[237] The Company has also prepared and provided a decommissioning cost estimate study and a depreciation study to support the proposed decommissioning costs and depreciation rates for East Bend, respectively.[238] Together, all recent modeling conducted by the Company supports the 2035 retirement date.

Intervenor witnesses supporting different retirement dates for East Bend, however, neither performed nor provided any studies, modeling, or resources analyses, much less any that support a different retirement date.[239] Sierra Club witness Ms. Sarah Shenstone-Harris performed no modeling of her own to support her suggestion that East Bend should retire by 2030, and instead relied on information provided by the Company and certain public information, despite acknowledging that running independent models is critical when evaluating these issues.[240] Mr. Kollen similarly provided no analysis when recommending that East Bend retire at 2041.[241]

[233] *Id.*
[234] Park Direct, p. 10.
[235] Scott Park Rebuttal Testimony (Park Rebuttal), p. 5 (Apr. 14, 2023).
[236] *Id.*
[237] Park Direct, p. 9.
[238] *See generally* Jeffrey T. Kopp Direct Testimony (Kopp Direct) (Dec. 1, 2022) and Attachment JTK-1; John J. Spanos Direct Testimony (Spanos Direct) (Dec. 1, 2022), Attachment JS-1.
[239] Sarah Shenstone-Harris Direct Testimony (Shenstone-Harris Direct), p. 7 (Mar. 10, 2023); Shenstone-Harris Cross, HVR at 7:30:29 (May 11, 2023).
[240] Shenstone-Harris Direct, p. 7; Shenstone-Harris Cross, HVR at 7:29:08 (May 11, 2023).
[241] *See generally* Kollen Direct, pp. 27–32; Lawler Rebuttal, p. 11.

Instead, he merely states it is not certain that East Bend is, or will be, uneconomic compared to other capacity resources by 2035 and that it is uncertain that the Company will retire the unit by that date.[242] In doing so, he entirely dismisses the Company's extensive IRP data and modeling.[243] The Company's analyses, on the other hand, are comprehensive, forward-looking, and utilize the appropriate data and market indicators to show that East Bend's retirement date is most likely 2035. Furthermore, as discussed in more detail below, the Company's proposal best balances reducing the risk of intergenerational inequity and significant balances due at the time of retirement, with a reasonable impact to customers now. It also provides the current and future Commissions with maximum flexibility to adjust depreciation again if needed, while Mr. Kollen's approach leaves little to no choice but for customers to pay for the retirement of East Bend and new generation at the same time if the plant should retire in 2035 as expected.

Intervenors have also failed to address the infeasibility of their positions as to the retirement date of East Bend. For instance, despite recommending a retirement date of 2030—less than seven years from now[244]—Ms. Shenstone-Harris has acknowledged that a number of barriers to retirement and replacement by 2030 exist, including: lengthy wait periods for PJM interconnection requests,[245] long procedural processes for planning for, filing, and obtaining a Certificate of Public Convenience and Necessity (CPCN) for any replacement resource[246] and constructing replacement resource facilities,[247] and supply chain and inflationary challenges that have made access to construction materials, third-party vendors, and heavy parts and equipment even more challenging in recent years.[248] The passage of SB 4 also requires the Company to now obtain approval from

[242] *See generally* Kollen Direct, pp. 27–32; Lawler Rebuttal, p. 11; Spanos Rebuttal, p. 3.
[243] Lawler Rebuttal, p. 11.
[244] Shenstone-Harris Cross, HVR at 7:36:14 (May 11, 2023).
[245] *Id.* at 7:37:37.
[246] *Id.* at 7:38:11, 7:38:46.
[247] *Id.* at 7:39:04.
[248] Shenstone-Harris Direct, p. 14; Shenstone-Harris Cross, HVR at 7:40:05 (May 11, 2023).

the Commission to retire a generating unit and to demonstrate the retirement and replacement is the most cost-effective alternative for customers.[249] How the Company is supposed to evaluate the best replacement resource(s), obtain a CPCN and interconnection approval, obtain Commission approval to retire the asset, *and* construct replacement resource facilities in the next seven years, given these looming challenges, is unclear, and Ms. Shenstone-Harris provides no further insight. A projected retirement date of 2035, however, which is fully supported by the Company's modeling and analyses in this case, provides the Company with adequate time to undertake these actions.

Regardless of the retirement date, the Company continues to evaluate the best replacement solutions for customers.[250] Maintaining safe, reliable, reasonable, and adequate service to customers has been and remains the priority.[251] The Company's most recent IRP described a "firm dispatchable resource" (FDR) as meeting that need for replacing East Bend, and Duke Energy Kentucky is committed to achieving that goal in the most efficient manner.[252] As such, the Company will continue to monitor the market, available technologies, and any opportunities to satisfy its need to replace retired generating assets in the coming years,[253] and will take a measured approach to transitioning these assets in a way that makes sense for and benefits customers.[254] The Company will bring those solutions to the Commission in due time for its approval, well in advance of any actual retirements, to ensure there is a seamless transition for customers.[255] The Company and the Commission can and will address replacement resource options in due course.

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[249] Lawler Rebuttal, pp. 3–9.
[250] Luke Direct, p. 13.
[251] *Id.*
[252] *Id.* at pp. 13–14; Park Direct, p. 8.
[253] Luke Direct, p. 14.
[254] Park Direct, p. 7.
[255] Luke Direct, p. 14.

At this time, however, addressing the disparity between East Bend's current depreciable life and its 2035 retirement is imperative.[256] If the Commission does not align depreciation rates with East Bend's substantiated and now probable end of useful life in 2035, the remaining net book value (NBV) of the plant at the end of 2035 would be substantially larger than it should otherwise be, making it impossible for the Company to credibly advance a request for retirement, and substantially increasing the costs for future customers who must pay for both an asset that is not providing actual service and its replacement.[257]

ii Effect on Credit Ratings

The Company's credit ratings are an important factor affecting the long-term viability of coal-fired generation assets like East Bend. The record in this case shows that credit rating agencies have concerns that Duke Energy Kentucky is poorly positioned for the inevitable carbon transition in the United States.[258] Both Standard & Poor's (S&P) and Moody's Investors Services (Moody's) have pointed to the Company's reliance on coal generation as a credit risk compared to other vertically-integrated utilities as it relates to a carbon transition risk profile.[259] S&P identifies exposure to coal generation as a key risk for Duke Energy Kentucky.[260] Moody's similarly finds that the Company has a higher carbon transition risk profile, observing that "Duke [Energy] Kentucky is poorly positioned for the carbon transition within the US regulated utility sector as its primary generating asset is a coal plant."[261]

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256 *Id.*
257 Lawler Rebuttal, pp. 8–9.
258 Bauer Direct, pp. 12–13; *see also* Quilici Direct, pp. 12–13.
259 Nowak Direct, p. 45.
260 *Id.* Specifically, S&P notes: "Environmental factors are a negative consideration in our credit rating analysis of Duke Energy Kentucky Inc. The company is more exposed compared to peers given its heavy reliance on coal-fired generation. Approximately 56% of the company's total electric generation fleet capacity of roughly 1,076 MW is coal-based, which exposes it to the potential for changing environmental regulations that might require significant capital investments. This exposure is somewhat mitigated by the parent's strategy to reach net-zero emissions by 2050." *Id.* (citing S&P Global Ratings, "Duke Energy Kentucky Inc.," June 16, 2022, at 7).
261 *Id.* (citing Moody's Investors Service, "Duke Energy Kentucky Inc.," January 19, 2022, at 4).

In recent years, the Company's reliance on coal-fired and high carbon emitting generation has indeed become problematic for investors, and a lack of clear strategy related to the carbon transition will continue to limit Duke Energy Kentucky's access to credit or make it more expensive to access credit at the customer's expense.[262] Retirement of East Bend in 2035 will address these rating agencies' concerns and help to restore the Company's access to the debt capital markets.[263] The significance of the Company's access to debt capital markets is described in further detail below.

iii Customer Benefits and Ratemaking Principles

The Company is continually monitoring the timing of the retirement and replacement of East Bend.[264] Aligning the depreciable life of the unit with its anticipated service life of 2035 now makes sense for customers over the long-term, as it reduces the costs for future customers when replacement generation goes into service and appropriately aligns the costs with the customers who are benefiting from the asset.[265] As the retirement date approaches, additional adjustments to depreciation expense may be required, as the Company is not actually proposing to retire East Bend in this proceeding.[266] That said, aligning the depreciation rate of East Bend with its expected retirement in 2035 will help minimize any intergenerational cross-subsidization of customer rates.[267]

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[262] *See* Bauer Direct, p. 13 ("In 2021, Duke Energy Kentucky ceased all marketing efforts to place $50 million of unsecured debentures with private placement investors after days of management presentations. The decision to cancel the transaction was due to feedback and aggressive demands from both existing growing number of asset managers have enacted new policies to limit exposure to utilities that have high levels of coal-fired/high carbon emitting generation. Without a clear and publicly communicated transition path away from coal generation to a cleaner fuel source, some investors simply would not entertain an order of any size and at any price.").
[263] *Id.*
[264] Park Direct, p. 11.
[265] *Id.*
[266] Lawler Rebuttal, p. 8; Shenstone-Harris Cross, HVR at 7:40:40 (May 11, 2023).
[267] Park Direct, p. 11.

Aligning depreciation expense with the useful life of East Bend provides a better ratemaking result for the Company's customers than—as Mr. Kollen suggests[268]—maintaining a longer life solely for depreciation purposes.[269] If the Commission does not adopt the Company's proposal, a minimum of approximately $134 million of prudently-incurred investments in the plant used to serve current customers will remain unrecovered as of 2035, and will thereafter have to be recovered from future customers after the plant is no longer in service.[270] This value only considers the investments the Company has made as of December 31, 2021 and does not even take into account any future capital investments that the Company will need to make at the plant to keep it running safely and reliably until retired.[271] Disregarding the plant's shortened useful life will create incremental expense, and an intergenerational equity issue, for future customers.[272]

Intergenerational equity in utility ratemaking is the principle that rates should cover the costs of providing service for the time period rates will be in effect.[273] The Commission has recognized the importance of the intergenerational equity principle in ratemaking in various proceedings.[274] Modifying an asset's depreciation schedule to match updates to its anticipated useful life supports this principle, as customers who benefit from the investment are those that actually pay for the investment.[275] If the Commission denies the Company's proposal to align East Bend's depreciation with its service life, future customers will be responsible for more than $134 million of costs incurred to serve a prior generation of customers while also being responsible for the costs of replacing that generation to provide current reasonable, adequate, and efficient

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[268] *See generally* Kollen Direct, pp. 27–32; *see also* Spanos Rebuttal, p. 3.
[269] Quilici Direct, p. 5.
[270] Lawler Rebuttal, p. 13
[271] Lawler Rebuttal, p. 13.
[272] Quilici Direct, p. 23.
[273] *Id.* at p. 24.
[274] *Id.* at pp. 24–25.
[275] *Id.* at p. 24.

service.[276] Aligning the depreciation of East Bend with its useful life is therefore to the benefit of customers.

Conversely, customers will be harmed if the Commission waits to take action in this case. Both the Company and the Commission should not wait until the Company files a CPCN for any future replacement resources to address East Bend's retirement date, as OAG witness Kollen otherwise suggests.[277] By that time, it may be too late for the Commission to take meaningful action to mitigate costs for customers regarding the remaining undepreciated NBV of the unit.[278] The Company believes that it is in the best interests of customers to spread the recovery of the net plant associated with East Bend over its useful life, as supported by extensive Company modeling and analyses, versus the "wait and see" approach advised by Mr. Kollen.[279] Data and analyses simply show that the unit is likely going to retire by 2035.[280] If the Commission only approves depreciation rates to align with a 2041 retirement date, the remaining NBV of the East Bend generation asset will be approximately $134 million at the end of 2035, before adding any new needed capital for maintenance between now and then.[281] Current customers would not be paying for their cost of service in using the asset. Rather, this balance will be borne by future customers and will serve as an impediment to the prudent retirement of the asset.[282] The recommendation that the Company should do nothing now and wait until it files a CPCN at some undefined point in the future violates ratemaking tenets, while the Company's proposal aligns with and supports those same principles.

[276] Lawler Rebuttal, p. 13.
[277] Kollen Direct, pp. 31–32; Lawler Rebuttal, pp. 12–13.
[278] *Id.*
[279] *Id.*
[280] *Id.*
[281] *Id.* at p. 13.
[282] *Id.*

iv Recent Kentucky Legislation Compels Alignment of Depreciation Expense.

In late March of 2023, SB 4 became law. The purpose of SB 4 was to create new sections of Chapter 278 of the Kentucky Revised Statutes to "prohibit the Kentucky Public Service Commission from approving a request by a utility to retire a coal-fired electric generator unless the utility demonstrates the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of the customers electric rate"[283] In its final form, SB 4: 1) grants the Commission authority to approve or deny the retirement of any electric generating unit owned by a utility; 2) requires a utility to file an application with the Commission requesting authorization before it can retire any electric generating unit; 3) creates a rebuttable presumption against retirement of a fossil fuel-fired generating unit; and 4) prohibits the Commission from approving the retirement, authorizing a surcharge for decommissioning of a unit, or taking any action that authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption against retirement is rebutted.[284]

In order to rebut the presumption against retiring an electric generating unit, a utility must demonstrate that: 1) it will replace the generation with capacity that is dispatchable, maintains or improves reliability, and maintains reserve margins; 2) unit retirement will not harm rate payers by causing them to pay incremental costs that could be avoided by not retiring a unit; and 3) the retirement decision was not due to federal incentives or benefits.[285] A major fallacy in the justification behind SB 4 is that it fails to consider the economics of a generating unit in the energy markets and incorrectly presumes that preventing an asset from retiring will nonetheless result in

[283] *See* Senate Bill 4, available *at:* https://apps.legislature.ky.gov/record/23rs/sb4.html.
[284] Lawler Rebuttal, pp. 4–5.
[285] *Id.*

the unit continuing to operate and serve load. Such is not the case. The capacity factors for East Bend are currently around 50 percent.[286] The unit's dispatchability is wholly dependent upon power prices and whether or not East Bend's dispatch costs are competitive.

The Company's ability to retire East Bend in compliance with the newly enacted SB 4 standard necessitates the Commission adjusting depreciation rates to align with the asset's estimated life span, as may change from time-to-time.[287] The remaining NBV of the asset factors into the calculation of net incremental costs that must be included in the asset retirement and replacement decision analysis. By not aligning the book life of the unit with its currently modeled and most likely retirement date, risks significant undepreciated plant remaining in rate base that future customers must now absorb, along with the replacement generation. This produces a more abrupt and significant increase in rates.[288] Failing to properly align depreciation expense artificially inflates those net incremental costs that must be considered in the SB 4 analysis, making the retirement and replacement hurdle more difficult to overcome. This creates a spiral whereby the Company has no alternative but to invest in an uneconomic unit to keep it capable of operation, which increases its dispatch costs, making it even more uneconomic and resulting in greater exposure for customers to the energy markets. If the Company is unable to cost-justify retirement and replacement because the remaining NBV of the asset is too high, the Company would have no choice but to continue investing in this asset and buying power in the market.

The Company is merely seeking to align its depreciation rates with the probable life of the assets so to mitigate the potential for the creation of stranded costs for customers and to have the opportunity to retire assets in the future with the least impact to customers.

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[286] Park Rebuttal, p. 26.
[287] Lawler Rebuttal, pp. 7–8.
[288] Park Rebuttal, p. 20.

h. Woodsdale

In contrast to East Bend, Woodsdale is currently projected to retire in 2040, and the Company is therefore seeking to align the depreciation rates and decommissioning expense for this asset with this date. In the 2019 Rate Case, the retirement date of Woodsdale was assumed to be 2032,[289] but the Company was disallowed from updating its depreciation rates for Woodsdale at that time.[290] Based upon expected service lives for simple CTs like Woodsdale and the performance of the units, their regular maintenance, and the fact that they are used for peaking service, the Company is now proposing to extend the useful life of this generating asset until 2040.[291] As such, the Company is also seeking to align depreciation and decommissioning expense for this asset with this new retirement date.[292] This mitigates, in part, the depreciation expense impact of aligning East Bend's depreciation life with its service life.[293] Extending Woodsdale's service life also provides greater flexibility to the Company's resource planning and mitigates impacts to customers who would otherwise experience costs of replacing two assets at approximately the same time.[294]

As with East Bend, the Company will evaluate the best replacement solutions for customers upon Woodsdale's retirement, and will continue to keep its responsibility to provide and maintain safe, reliable, reasonable, and adequate service to customers at the forefront of this analysis.[295] At

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[289] Luke Direct, p. 13.
[290] Spiller Direct, p. 29.
[291] *Id.*; Luke Direct, p. 13.
[292] Spiller Direct, p. 29.
[293] *See id.*; Lawler Direct, pp. 5–6 ("[East Bend's earlier projected retirement date of 2035] is driving approximately $11 million of the total $35 million increase in depreciation expense. Partially mitigating this increase is the fact that the estimated retirement date of Woodsdale is now projected to be 2040, eight years later than its originally planned retirement date. Included in the $35 million increase in depreciation expense is an approximately $7 million decrease associated with this extension of useful life."); Luke Direct, p. 13 ("This has the added benefit of offsetting some of the incremental depreciation expense associated with aligning East Bend's depreciable life to its expected service life . . . .").
[294] *Id.*
[295] *See Id.* at pp. 13–14.

this time, though, it is critical that Woodsdale's service life be aligned with its depreciation rate.[296] Notably, neither Ms. Shenstone-Harris nor Mr. Kollen oppose the Company's proposal to align Woodsdale's depreciation expense with the later retirement date of 2040.[297] However, neither Ms. Shenstone-Harris nor Mr. Kollen propose any recommendations as to how the Company would replace two major generating stations within a twelve month period, nor do they consider the economic impact to customers of such a scenario.[298]

i. Amortization of Rate Case Expense

In this case, the Company included an original estimate of rate case expense of $1.136 million and tendered regular updates as to its actual rate case expense through the course of this proceeding. As of May 31, 2023, the total amount of estimated rate case expense is $1.002 million.[299] The Company requests a five-year amortization period of this expense.[300] Additionally, the Company is seeking to recover the unamortized balance of rate case expense from the 2019 Rate Case, approximately $0.068 million.[301] The Company opposes any recommendation to amortize this balance over a new five-year period,[302] as the Company's proposal to recover the unamortized balance in this case is consistent with its past requests.

j. Property Tax Expense

Subject to adjustments related to the property taxes associated with four capital projects that are currently in the Company's Environmental Surcharge Mechanism (ESM), the Company

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[296] *Id.* at p. 14.
[297] Lawler Rebuttal, p. 11. Ironically, while Mr. Kollen recommends that the Commission reject the Company's proposal to adjust depreciation expense to align with a 2035 retirement date for East Bend, he does not object to the Company's proposal to adjust the expense to align with a later retirement date for Woodsdale of 2040. *Id.* at p. 12. This position is confusing and inconsistent with both depreciation principles and ratemaking principles in general.
[298] Park Rebuttal, p. 23.
[299] Staff-DR-01-014 5th Supplemental Attachment 1.
[300] Steinkuhl Direct, p. 19.
[301] Application, p. 6, Schedule F-6.
[302] Randy A. Futral Direct Testimony (Futral Direct), p. 14 (Mar. 10, 2023).

has submitted an estimated $18.139 million in property tax expense in the test year in this proceeding.[303] The Company accounts for property tax based on Kentucky's property tax year cycle, which is based on calendar year data.[304] Kentucky property tax for a given calendar year is related to the Company's financial statements from the prior calendar year.[305] The Kentucky Department of Revenue (DOR) issues tax year assessments in the same calendar year, but tax bills are issued and paid in the following calendar year.[306]

The only witness that contests the Company's property tax expense included in the test year is OAG witness Mr. Randy Futral. Mr. Futral recommends that the Commission reduce the Company's projected property tax expense to reflect the Company's 2022 actual expense escalated through the end of the test year for increases in electric net plant and using the Company's 2.0 percent per year property tax rate increase.[307] But Mr. Futral makes flawed assumptions in analyzing the Company's property tax expense data and, in turn, in making his recommendation noted above.

The Kentucky DOR utilizes the unit value method to calculate the assessed value of the Company's property.[308] The unit value method includes analyzing both the Company's costs and net operating income.[309] Historically, however, the Company testified that the Kentucky DOR has relied entirely (100 percent) on the income component of the overall unit value analysis.[310] Therefore, any property tax estimate that relies solely on the cost component of the unit value method could not possibly calculate an accurate estimate of property tax in any year.[311]

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[303] John R. Panizza Revised Rebuttal Testimony (Panizza Revised Rebuttal), p. 6 (May 5, 2023).
[304] *Id.* at p. 2; Futral Cross, HVR at 9:00:55 (May 11, 2023).
[305] Panizza Revised Rebuttal, p. 2.
[306] *Id.*
[307] Futral Direct, p. 19.
[308] Panizza Revised Rebuttal, p. 5.
[309] *Id.*
[310] *Id.*
[311] *Id.*

Despite this, Mr. Futral's property effective tax rate (ETR) does not have a component to account for changes in operating income.[312] Mr. Futral notes that this is because the Company's "operating income was projected to decrease from 2021 actual amounts significantly before new rates from this case would go into effect,"[313] and that it was therefore not appropriate to reflect reductions in projected operating income.[314] However, Mr. Futral's analysis of property tax expense and net operating income uses data from Schedule I to the Application,[315] and this data pertains only to the projected base year and the forecasted test year.[316] Both the projected base year (the twelve month period ending February 28, 2023) and the forecasted test year (the twelve month period ending June 30, 2024) are *not* calendar years.[317] As such, Schedule I to the Application does not present the Company's net operating income in terms of calendar year data, which sharply contrasts with DOR's method of calculating property taxes based on calendar year data.[318] Rather, the Company's electric department net utility operating income for 2021 was $59.813 million,[319] while the Company's 2022 FERC Form 1 indicates that this value *increased* in 2022 to $61,216,563.[320] Mr. Futral's assumption that the Company's operating income was not projected to increase is therefore inherently flawed, as is his decision to omit an operating income component from his ETR is flawed. Mr. Futral's method for calculating property tax expense is thus in direct conflict with the method by which DOR actually calculates property taxes.

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[312] Duke Energy Kentucky Question No. 36 to OAG, p. 1.
[313] *Id.*
[314] *Id.*
[315] Futral Cross, HVR at 9:01:51 (May 11, 2023); Duke Energy Kentucky Question No. 36 to OAG, p. 1.
[316] Futral Cross, HVR at 9:04:06 (May 11, 2023).
[317] *Id.* at 9:04:02, 9:04:57.
[318] *Id.* at 9:00:55 (May 11, 2023).
[319] *Id.*
[320] *See* DEK Exhibit 5 (FERC Form 1); Futral Cross, HVR at 9:22:09 (May 11, 2023).

In contrast, the Company incorporated potential increases in net operating income in its escalation of ETR, which, as noted above, is in line with DOR precedent.[321] The Company's property tax calculation has properly accounted for the fact that the test year is not a calendar year. In this case, each tax year must be independently analyzed and allocated to the test period.[322] Because the test period in this case is the twelve months ending June 30, 2024, the test period covers six months each of Kentucky property tax years 2023 and 2024.[323] As such, the Company utilized available and projected data for calendar years 2023 and 2024, calculated the property tax expense for each year, and then allocated fifty percent of each year's expense to the test period.[324]

The Commission should therefore reject Mr. Futral's arguments related to property tax expense and accept the Company's proposed property tax expense included in the test period. The Company has used the correct operating income data inputs and the correct time periods to calculate property tax expense. Mr. Futral, on the other hand, initiated his calculation starts with an incorrect starting point, includes activity that may not occur during the test period, and fails to incorporate potential changes in net operating income in his escalation of ETR.

4. Rate of Return

a. Return on Equity (ROE)

In this case, the Company is requesting an authorized ROE of 10.35 percent,[325] 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."[326] As Company witness Mr. Chris Bauer explains:

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[321] Panizza Revised Rebuttal, p. 5.
[322] Panizza Revised Rebuttal, pp. 3–4.
[323] *Id.*; Lawler Direct, p. 3.
[324] Panizza Revised Rebuttal, pp. 3–4.
[325] Nowak Direct, p. 9 (Dec. 1, 2022).
[326] *Id.*

> 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.[327]

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.[328] In their reviews of Duke Energy Kentucky's credit ratings, rating agencies have consistently noted specific credit challenges facing the Company, including credit metrics below standard thresholds, the Company's relatively small size when compared to other vertically-integrated utilities, and an elevated risk associated with transitioning away from carbon generation.[329] Given these challenges, and as discussed in further detail below, the Company's ROE should be authorized at 10.35 percent.

i ROE Models and Risk Factors

Duke Energy Kentucky utilized four different ROE modeling methodologies to determine its requested ROE of 10.35 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 the Expected Earnings analysis.[330] Use of these methodologies in combination is critical to determining a fair and reasonable ROE, as strict adherence to any single approach, or the specific results of any single approach, can lead to flawed conclusions.[331] No model can exactly pinpoint the true cost of equity, but each is designed to provide a unique estimate of the return

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[327] Bauer Direct, p. 9.
[328] *Id.* at p. 3.
[329] *See id.* at pp. 11–12.
[330] Nowak Direct, pp. 3–4.
[331] *See id.* at p. 29.

required to attract equity investment.[332] The Company's requested ROE is therefore based on the range of results produced by the four methodologies indicated above.[333] 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.[334] The Company's ROE analyses conducted here, as well as their underlying data, have been characterized as generally reasonable and reliable by Intervenor witnesses in this proceeding.[335]

By contrast, other ROEs proposed in this case are not supported by the array of methods described above. For instance, OAG witness Richard Baudino's recommended ROE of 9.55 percent relies primarily on the DCF method and inappropriately excludes the result of the forward-looking CAPM analysis of 12.48 percent, which was notably higher than the ROE requested by the Company in this case.[336] Relying almost solely on the constant growth DCF method is a flawed way of approaching ROE analysis, as this method requires several assumptions to hold true, including: (1) a constant growth rate for earnings and dividends, (2) a stable dividend payout ratio, and (3) a constant price-to-earnings ratio.[337] Yet the price-to-earnings ratio for utilities over the last ten years has not remained constant, as Mr. Baudino himself admitted.[338] Walmart witness Steve Chriss additionally relied solely on past authorized ROEs in the country, and omitted any DCF, CAPM, Risk Premium, or Expected Earnings analyses. He also failed to perform any

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[332] *Id.* at p. 5.
[333] *Id.*
[334] *Id.* at pp. 5–6.
[335] *See* Baudino Cross, HVR at 9:50:43 (admitting that Company witness Nowak's approach to the DCF model is generally reasonable); *id.* at 9:48:53 (agreeing that Value Line data, which was used by Mr. Nowak in developing his ROE recommendation, is reliable); Richard A. Baudino Direct Testimony (Baudino Direct), p. 35 (Mar. 10, 2023) (noting that "Witness Nowak's approach to the DCF is generally reasonable").
[336] *Id.* at p. 30 ("Regarding the CAPM results, the forward-looking CAPM ROE of 12.48% is implausibly high and represents an extreme outlier. . . . Thus, I do not recommend that the Commission consider this result.").
[337] Baudino Cross, HVR at 9:39:51 (May 11, 2023).
[338] *Id.* at 9:40:26.

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.[339] Failure to conduct additional (or any) analyses using different methodologies by these witnesses results in exclusion of the full range of appropriate ROEs and, in turn, imprecise ROE recommendations.

The witnesses proposing and supporting a different ROE in this case also failed to fully consider and analyze changing capital market conditions and risk factors that influence the Company's ROE. Walmart witness Chriss admittedly provided no analysis of how capital market conditions have evolved when discussing historic authorized ROEs for other utilities since 2019;[340] these conditions include COVID-19 and its significant effects on the economy since 2020;[341] increasing interest rates;[342] peak inflation rates that the country has not experienced since the 1980s;[343] and tightened monetary policy by the Federal Reserve such that the Fed Funds rate is above 5% for the first time since 2007.[344] OAG witness Baudino similarly omitted from his testimony any discussion of the various risk factors of the Company, including business risk, regulatory risk, and investment risk, although he acknowledged that market credit ratings agencies and investors alike consider these risks when evaluating a utility's credit ratings.[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.

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[339] Chriss Cross, HVR at 4:43:41 (May 11, 2023).
[340] *Id.* at 4:42:30.
[341] *Id.* at 4:42:45.
[342] *Id.* at 4:42:56.
[343] *Id.* at 4:43:05.
[344] *Id.* at 4:43:27.
[345] Baudino Cross, HVR at 9:37:32.

ii Proxy Group and Authorized ROEs

To conduct the ROE analyses described above, Company witness Mr. Joshua 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.[346] 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.[347] Mr. Nowak used various screening criteria to arrive at a proxy group that investors would view as comparable to Duke Energy Kentucky.[348]

That the Company is a vertically-integrated electric utility is important for selecting the appropriate proxy group and comparing recently authorized ROEs for various other utilities. While OAG witness Mr. Baudino utilized a group of vertically-integrated electric utilities in his proxy group for his DCF analysis,[349] he relies on Edison Electric Institute (EEI) data that includes *non*-vertically-integrated electric utilities in comparing the Company's requested ROE to recently authorized ROEs for other utilities.[350] This data includes other utilities and cases, including transmission-only cases and limited-issue riders.[351] Mr. Baudino agrees that vertically-integrated electric utilities are a better proxy for the Company than these other utilities included in his cited ROE data.[352] When analyzing the data cited by Mr. Baudino, but only including authorized ROEs for vertically-integrated electric utilities, the average authorized ROE is 9.87 percent,[353] higher than both values cited by Mr. Baudino for the third and fourth quarters of 2022.[354]

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[346] Nowak Direct, p. 25.
[347] *Id.*
[348] *Id.* at pp. 26, 28.
[349] Baudino Direct, p. 15.
[350] Baudino Cross, HVR at 9:32:53 (May 11, 2023).
[351] *Id.*
[352] *Id.* at 9:32:35.
[353] *Id.* at 9:34:13.
[354] Baudino Direct, p. 42

Walmart witness Chriss's analysis of recently authorized ROEs since 2019 also includes decisions under considerably different capital market conditions that have little bearing on the returns required by investors in the current capital market. As discussed above, Mr. Chriss failed to fully consider and analyze changing capital market conditions that influence the Company's ROE. Authorized ROEs from 2020 and 2021, after the decline in interest rates in 2020 and 2021 driven by the Federal Reserve's unprecedented actions to respond to the COVID-19 pandemic, are not a reasonable comparison for evaluating the cost of equity in the current capital market environment.[355] While Mr. Chriss's analysis includes more recent decisions from 2023, and appropriately includes only vertically-integrated electric utilities, his testimony omitted two recently authorized ROEs for comparable proxy companies to Duke Energy Kentucky. Although Mr. Chriss's data indicates that the average ROE authorized for vertically-integrated utilities as of March 7, 2023 was 9.68%,[356] two additional and relevant ROEs have been authorized since that date: on March 24, 2023, Upper Peninsula Power Co. was authorized an ROE at 9.90 percent, while on April 27, 2023, Liberty Utilities was authorized an ROE of 10.00 percent.[357] These two ROEs notably increase the average of the data analyzed by Mr. Chriss, and are closer to the Company's requested ROE in this case. This additional context confirms the fairness and reasonableness of the Company's proposed ROE.

When the analysis of past authorized ROEs is limited to decisions for comparable companies (*i.e.*, vertically-integrated electric utilities), in capital market conditions that are similar to the current environment (*i.e.,* recent cases in 2023) the average authorized ROE demonstrates the reasonableness of the Company's requested ROE. With the additional context of Company

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[355] Joshua C. Nowak Rebuttal Testimony (Nowak Rebuttal), p. 6 (Apr. 14, 2023).
[356] *See* Steve W. Chriss Direct Testimony (Chriss Direct), pp. 17–20 (Mar. 10, 2023); Chriss Cross, HVR at 4:44:37 (May 11, 2023).
[357] *Id.* at 4:45:02.

witness Mr. Nowak's multi-method approach to his ROE analysis—which neither Intervenor witness performed—the Company's requested ROE is supported by a well-rounded analysis and the appropriate forward-looking risk and other market information.

b. Capital Structure

Duke Energy Kentucky's capital structure proposed for approval in this case is comprised of 47.855 percent debt and 52.145 percent equity, after making adjustments for purchase accounting and other items and updates to reflect the Company's average equity ratio over the forecast period.[358] 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.[359] Approval of this capital structure will help the Company maintain its credit quality to meet its ongoing business and service objectives.[360]

This level is also consistent with the Company's target credit ratings.[361] At the outset of this proceeding, the Company had BBB+ and Baa1 credit ratings from S&P and Moody's, respectively, with "Stable" outlooks for each credit agency.[362] The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years).[363] A "Stable" outlook at S&P and Moody's is an indication that the credit ratings are not likely to change in the immediate term.[364] That said, a change in outlook could occur if the Company experiences a change in its business, regulatory, or financial risk.[365]

[358] Bauer Direct, p. 14; Christopher R. Bauer Rebuttal Testimony (Bauer Rebuttal), p. 2 (Apr. 14,2023).
[359] Bauer Direct, p. 14.
[360] *Id.*
[361] *Id.*
[362] *Id.* at p. 6.
[363] *Id.* at p. 7.
[364] *Id.*
[365] *Id.*

Despite the Company's "Stable" outlook at the start of this proceeding, on April 24, 2023, Moody's issued a press release wherein it revised its outlook for the Company from "Stable" to "Negative."[366] While a credit opinion expanding on this revised outlook is forthcoming, Moody's indicated that the revised outlook was due to sustained credit metrics below the target level and the anticipation that they would remain below that level if an "unfavorable" result occurred in this proceeding.[367] This revised outlook demonstrates the importance of the Company's capital structure as a component of its overall credit quality. Equity capital is subordinate to debt capital, thereby providing a cushion and safer returns for debt investors.[368] The Company therefore seeks to maintain a level of equity in the capital structure (52.145 percent) that ensures high credit quality, while minimizing its overall cost of capital.[369] This is particularly important in light of Moody's revised outlook.

The revised Moody's outlook also demonstrates the importance of setting a utility's capital structure going forward, as rating agencies like Moody's analyze a number of forward-looking indicators to determine a company's credit rating outlook in the near future. For instance, Moody's noted that it considered the possibility of an unfavorable future outcome in this case in revising the Company's outlook to "Negative."[370]

Thus, OAG witness Baudino's claims that the Company's requested equity ratio, as part of its overall capital structure, is excessive because it is higher than its recent historical common equity ratios is confusing,[371] particularly when viewed in light of the fact that witness Baudino has admitted that the Commission in this proceeding is being asked to authorize the Company's capital

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[366] *See* Nowak Direct, HVR 3:39:25 (May 10, 2023); Bauer Direct, HVR at 4:15:08 (May 10, 2023).
[367] Nowak Cross, HVR at 3:52:33, 3:53:05 (May 10, 2023).
[368] Bauer Direct, p. 9.
[369] *Id.*
[370] Nowak Cross, HVR at 3:52:33, 3:53:05 (May 10, 2023).
[371] *See* Baudino Direct, pp. 3–4.

structure *going forward*.[372] This claim also does not align with basic ratemaking and capital market principles, as a utility that could only obtain the historical equity ratio to which it is currently managing could never improve its equity ratio, even in a negative-outlook environment. Witness Baudino's lower equity ratio recommendation is also based on the fact that the Company was able to maintain its credit ratings at this lower ratio.[373] But the Company's rating indeed declined from A- to BBB+ from 2020 through 2021, and its outlook has been revised by Moody's from "Stable" to "Negative," facts which witness Baudino acknowledges.[374] The Company is therefore working to improve its equity ratio—and overall capital structure—and should be permitted to do so because its historical capitalization is no longer sufficient to maintain its credit ratings, and that is the exact scenario the Company is currently facing.

Walmart witness Chriss's capital structure recommendation also suffers from a number of shortcomings. In providing information in his direct testimony related to average authorized equity ratios awarded to vertically-integrated electric utilities in 2022, Mr. Chriss included authorized equity ratios from Arkansas, Indiana, and Michigan.[375] This is erroneous, as these states include sources of non-investor supplied capital, such as deferred taxes, in authorized utility capital structures,[376] while Kentucky and this Commission do not.[377] As such, the Company did not include these items in its requested capital structure in this case.[378] Excluding the Arkansas, Indiana, and Michigan cases from Mr. Chriss's data puts the average authorize equity ratio for similar utilities in 2022 at 52.13 percent, incredibly close to the Company's requested equity ratio of 52.145 percent. As of 2023, there has also been a "noticeable shift upward" in authorized equity

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[372] Baudino Cross, HVR at 9:53:27 (May 11, 2023).
[373] Baudino Direct, p. 32.
[374] Baudino Cross, HVR at 9:56:23 (May 11, 2023).
[375] *See* Chriss Direct, Exhibit SWC-3, pp. 3–4; Chriss Cross, HVR at 4:46:28 (May 11, 2023).
[376] Nowak Rebuttal, p. 30; Chriss Cross, HVR at 4:47:47 (May 11, 2023).
[377] *Id.* at 4:47:58.
[378] *Id.* (noting that it "does not appear" that the Company included these items in its requested capital structure).

ratios, as the reported average authorized equity ratio for similar utilities for 2023 is 52.31 percent, higher than the Company's proposal in this case.[379] For additional context, Mr. Nowak performed an analysis of the actual common equity ratios employed by the operating companies held by a peer group of vertically-integrated electric utilities, and by that comparison, the Company's requested equity ratio is somewhat below the peer group average actual equity ratio of 53.06 percent.[380]

The Company's proposed equity ratio is therefore in line with recently authorized equity ratios for similarly-situated utilities. As such, the Company's proposed capital structure of 52.145 percent equity and 47.855 debt is fair, reasonable, and based on forward-looking and objective market data, and should be approved by this Commission.

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.[381] The demand allocation methods are: (1) the Average of the Twelve Coincident Peaks (12 CP) method; (2) the Average and Excess (A&E) method; and (3) the Production Stacking method.[382] The Company recommends using the 12 CP method because it is generally accepted in the utility industry, was approved by the Commission in the Company's last rate case, and recognizes that the Company's current generating facilities are in place precisely to meet the monthly maximum peak loads of customers.[383] Kroger witness

[379] *See* Chriss Direct, Exhibit SWC-3, p. 5; Chriss Cross, HVR at 4:49:48, 4:50:15 (May 11, 2023).
[380] Nowak Direct, pp. 48–49.
[381] James E. Ziolkowski Direct Testimony (Ziolkowski Direct), p. 5 (Dec. 1, 2022).
[382] *Id.*
[383] *Id.* at pp. 6–7.

Mr. Justin Bieber agrees that the 12 CP method is reasonable to use in this case.[384] Additionally, Walmart witness Chriss does not oppose use of the 12 CP methodology.[385] As such, the CCOSS using the 12 CP method should be used as the basis for rate design in this proceeding.

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 7.526 percent overall return on rate base being requested in this case.[386] Thus, developing rates that generate the amount of 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.[387]

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.[388] The first step involves eliminating 5 percent of the subsidized revenues between customer classes based on present revenues.[389] The second step then allocates the rate increase to customer classes based on electric original cost depreciated (OCD) rate base.[390] While rate subsidies will persist after this allocation method,[391] this method gradually moves each rate class towards its cost of service while mitigating rate shocks customers may otherwise experience from sudden increases in their electric bills.

[384] Justin D. Bieber Direct Testimony (Bieber Direct), p. 8 (Mar. 10, 2023).
[385] Chriss Direct, p. 15.
[386] Ziolkowski Direct, p. 28; Bieber Direct, p. 11.
[387] Ziolkowski Direct, p. 28; Bieber Direct, p. 11.
[388] Ziolkowski Direct, p. 28; Bieber Direct, p. 11.
[389] Ziolkowski Direct, pp. 28–29; Bieber Direct, p. 11.
[390] Ziolkowski Direct, pp. 29; Bieber Direct, p. 11.
[391] *Id.* at p. 12.

Walmart does not oppose the Company's revenue allocation proposal so long as the Commission authorizes the Company its full proposed revenue requirement increase.[392] 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.[393] In that event, Walmart recommends that the Commission increase the percentage of the proposed revenue-neutral adjustment approximately 5 percent such that classes are moved closer to their costs of service.[394] Because the Company's revenue apportionment is aligned with its CCOSS results and the regulatory principles of gradualism and rate shock mitigation, the Company urges the Commission to approve its requested CCOSS.

6. Proposed Rate Design

a. Proposed Increase in Rate RS – Residential Service (Rate RS) Customer Charge

The Company is proposing no changes to customer charges except for a proposed small increase in the Rate RS customer charge of $0.40.[395] This increase is modest and will allow the Company to continue to provide safe, reliable electric service to residential customers in alignment with their costs of service. This increase is unopposed by all Intervenors in this proceeding.[396]

b. Experimental Residential Service – Time of Use with Critical Peak Pricing (Rate RS-TOU-CPP)

The Company is proposing to implement a new rate, Rate RS-TOU-CPP. Rate RS-TOU-CPP is an optional, time-based, dynamic rate for customers who currently take service on Rate

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[392] Chriss Direct, p. 19.
[393] *Id.*
[394] *Id.*
[395] Bruce L. Sailers Direct Testimony, p. 9 (Dec. 1, 2022).
[396] *See generally* Kollen Direct, Futral Direct, Baudino Direct, Shenstone-Harris Direct, Bieber Direct, Chriss Direct, and Patricia D. Kravtin Direct Testimony (Kravtin Direct) (Mar. 10, 2023) (noting no recommendations related to the Rate RS customer charge).

RS.[397] Rate RS-TOU-CPP is a time-of-use (TOU) rate structure that may include daily Super Off-Peak (*i.e.*, Discount), Off-Peak, On-Peak, and, potentially, Critical Peak periods.[398] This dynamic structure recognizes significant load periods through Critical Peak Pricing (CPP) and the declaration of Critical Peak Days (CPDs), which are limited to ten CPDs annually absent a system emergency to prompt an additional CPD.[399] CPD notices will be provided to customers via email or text message providing customers the opportunity to lower their consumption and reduce their bills.[400]

This proposed structure will facilitate the continuing customer adoption of technology such as EVs and internet-enabled smart thermostats.[401] This proposed rate provides customers the opportunity to lower their electric bill through adjustments to electric consumption behaviors, as the TOU structure provides a shorter on-peak period that facilitates greater customer response opportunities.[402] Customers who shift load to the year-round 1 a.m. to 6 a.m. Discount period—for instance, customers with EVs—will realize monthly bill savings.[403] These price signals will encourage customers to shift load to off-peak periods, resulting in lower peak demand and alleviating the strain on the electric system that occurs during the highest demand periods.[404]

Sierra Club recommends that the Company modify its Rate RS-TOU-CPP to "strengthen the on-peak to off-peak differential."[405] While Sierra Club witness Shenstone-Harris argues that the rate differential between on-peak and off-peak hours is not large enough to incentivize

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[397] Sailers Direct, p. 15.
[398] *Id.*
[399] *Id.*
[400] *Id.*
[401] *Id.*
[402] *Id.* at pp. 15–16.
[403] *Id.* at p. 16.
[404] *Id.*
[405] Shenstone-Harris Direct, p. 58 (Mar. 10, 2023).

customers to adopt the rate,[406] she has not quantified how large the differential should be to properly incentivize customers.[407] When citing "EV tariffs and enrollment levels in multiple other jurisdictions" that she has reviewed, Ms. Shenstone-Harris does not provide any empirical evidence that a higher differential has succeeded for those utilities in those jurisdictions in creating significantly higher enrollment rates.[408]

Additionally, Ms. Shenstone-Harris's limited analysis related to Rate RS-TOU-CPP is tied to dollar savings specific to EVs,[409] but Rate RS-TOU-CPP is not EV-specific or tied to EV adoption or usage; it is a whole account rate.[410] Further, analysis of the proposed rate under a dollar-savings threshold fails to acknowledge that the on-peak rate is 50 percent higher than the off-peak rate, *and* that the super off-peak rate is 20 percent lower than the off-peak rate.[411] Indeed, what Ms. Shenstone-Harris considers to be an insignificant dollar differential is likely actually a function of the relatively low pricing of the proposed rate. As such, customers will benefit from the proposed rate both in terms of savings and a relatively low rate to begin with. The Commission should therefore approve this new rate as an innovative, beneficial offering that is sufficient to incentivize an array of the Company's customers to shift their load to off-peak times.

c. Distribution Pole Attachments (Rate DPA) Pole Attachment Charges

In this case, the Company is proposing to update its pole attachment charges under Rate DPA using the most recent FERC Form 1 data that was available when the Company filed its

[406] *Id.* at pp. 55–56; Shenstone-Harris Cross, HVR at 7:56:43 (May 11, 2023).
[407] *Id.* at 7:58:18; Bruce L. Sailers Rebuttal Testimony (Sailers Rebuttal), p. 4 (Apr. 14, 2023) ("Absent a specific metric or recommendation for the Company to evaluate, there is no apparent justification for altering the charges proposed by the Company.").
[408] Shenstone-Harris Cross, HVR at 8:00:47 (May 11, 2023).
[409] *Id.* at 7:56:10, 7:59:13.
[410] *Id.* at 7:58:27; Sailers Rebuttal, p. 4.
[411] Shenstone-Harris Cross, HVR at 7:59:22 (May 11, 2023).

Application in this proceeding.[412] Specifically, the Company proposes increasing its pole attachment charges from $8.59 to $9.99 per foot for a two-user pole, and from $7.26 to $8.61 per foot for a three-user pole.[413] The Company revised this per foot charge using the Commission-designated calculation process set forth by order in Administrative Case No. 251.[414] The Company also proposed other changes related to Rate DPA in Case No. 2022-00105 that have been approved by the Commission in that proceeding.[415] Those approved changes do not affect the total revenue requirement in this case.[416]

The pole attachment charges proposed in this case have been calculated using the number of non-unitized poles that the Company had at the end of 2021.[417] While the number of non-unitized poles as of year-end 2021 that were subsequently unitized during 2022 was not known to the Company when this case was first filed, the Company has since updated its calculation to reflect this known value along with the corresponding investment.[418] This updated value resulted in the same $9.99 per foot for a two-user pole and a one-cent increase in the per foot charge for a three-user pole ($8.62).[419] Because these values are nearly (if not completely) identical to the Company's originally-proposed charges, the Company recommends that the Commission approve the updated charges as filed in the Application.[420]

KBCA opposes the Company's proposed increase in pole attachment charges and instead recommends a reduced pole attachment rate of $9.62 for two-user poles and $7.96 for three-user poles. However, KBCA witness Ms. Patricia Kravtin's proposed calculations of $9.62 for two-

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412 Sailers Direct, p. 28.
413 *Id.* at Attachment BLS-1, p. 31.
414 *Id.* at p. 29.
415 Sailers Rebuttal, pp. 13–14; *see also id.* at Attachment BLS-Rebuttal-1.
416 *Id.* at p. 15.
417 *Id.* at p. 13.
418 *Id.*
419 *Id.* at pp 13–14.
420 *Id.*

user poles and $7.96 for three-user poles differ from the Company's proposed charges because Ms. Kravtin's analysis contains calculation errors.[421] First, Ms. Kravtin recommends the addition of 2,464 poles to the calculation,[422] but these poles are not unitized and do not represent only 35-, 40-, and 45-foot poles.[423] Of the non-unitized poles as of the end of 2021, the correct number of poles for these heights that were not unitized but were unitized during the year 2022 are 71, not 2,464.[424] Ms. Kravtin also adds additional poles to the 35-, 40-, and 45-foot pole counts, but neglects to add the corresponding investment associated with those poles of $15,727.20, $15,325.25, and $74,647.88, respectively.[425] The Company's analysis does not contain these errors, and its pole attachment charges have therefore been calculated correctly.

Ms. Kravtin also proposes unauthorized changes to the Commission-approved calculation methodology for pole attachment rates outlined in Administrative Case No. 251,[426] despite her acknowledgement that Administrative Case No. 251 governs the methodology utilities must use in calculating their pole attachment rates.[427] Specifically, Ms. Kravtin recommends that the Commission either eliminate the difference in the charges between two- and three-user poles or include 50-foot poles in the attachment charge calculation. Administrative Case No. 251 "allow[s] deviations from the mathematical elements found reasonable herein only when a major discrepancy exists between the contested element and the average characteristics of the utility, and the burden of proof should be upon the party asserting the need for such deviation."[428] While Administrative Case No. 251 does not define "major discrepancy," Ms. Kravtin has not

[421] Kravtin Direct, p. 7.
[422] *Id.* at p. 8.
[423] Sailers Rebuttal, p. 14.
[424] *Id.*
[425] *Id.*
[426] *Id.* at p. 16. The Company is also not aware of any other cases impacting the charge calculation methodology laid out in Administrative Case No. 251. *Id.*
[427] Kravtin Cross, HVR at 9:41:21 (May 11, 2023).
[428] Sailers Rebuttal, pp. 12–13.

demonstrated that the current calculation results in a poor estimate for pole attachment rates.[429] Simply stating that the Company now uses more 50-foot poles does not demonstrate that a major discrepancy exists.[430] To include 50-foot poles in the calculation, the Company would need to perform a study to calculate the usable space assumption for 50-foot poles, as these assumptions are not contained in Administrative Case No. 251.[431] Such a study is unnecessary and inappropriate at this time, as Ms. Kravtin has not demonstrated that a major discrepancy exists here.

As such, the Commission should approve the Company's proposed pole attachment rates for Rate DPA. These updated rates are supported by the Company's FERC Form 1 data and recent data available to the Company related to non-unitized pole counts, and follows the governing procedures outlined in Administrative Case No. 251.

d. Time-of-Day Rate for Service at Distribution Voltage (Rate DT)

The Company is proposing updates to the structure of one of its commercial rates, Rate DT, in recognition of potential future customer technology adoption regarding EV off-peak charging behavior.[432] The Company proposes to create a separate demand charge for recovery of the CCOSS's distribution demand revenue component while reducing the other charges commensurately.[433] The proposed distribution demand charge targets the recovery of distribution demand costs to serve, while distribution demand costs to serve are accordingly removed from the other rate components.[434]

[429] *Id.* at p. 13.
[430] *Id.*
[431] *Id.* at pp. 16–17; Kravtin Cross, HVR at 6:45:03 (May 11, 2023) (agreeing that Administrative Case No. 251 does not discuss usable space assumptions for 50-foot poles).
[432] Sailers Direct, p. 10.
[433] *Id.*
[434] *Id.*

Use of non-coincident demand charges, as is proposed under Rate DT in this case, is common among utilities and are an appropriate charge for non-residential customer rates, such as those taking service under Rate DT.[435] In fact, non-coincident demand charges reflect a customer's maximum use of the distribution system and is a commonly used and reasonable methodology to spread the collection of the distribution demand revenue requirement among the customers in a non-residential class.[436] Non-coincident demand charges thus fairly reflect use of a distribution system and, in this case, will not result in EV customers paying more than their fair share of costs for off-peak charging, especially where "on-peak" hours at the distribution feeder and/or substation are not coincident with the overall system.[437] These charges also appropriately reflect cost-causation per the Company's CCOSS.[438] Sierra Club witness Shenstone-Harris's arguments to the contrary are therefore meritless.[439]

Ms. Shenstone-Harris's testimony on this subject also falls short because it singles out EV charging load,[440] despite the fact that Rate DT is a whole-account, non-EV-specific rate.[441] Ms. Shenstone-Harris's bill impacts review fails to account for this basic principle inherent in Rate DT's updated design.[442] Most Rate DT customers have existing non-EV load and have maximum demand during the on-peak period.[443] Under the current rate design, EV load can be added off-peak with no additional demand charge bill impact until the customer's off-peak demand exceeds the customer's current maximum demand.[444] As a result, the proposed distribution demand charge

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[435] Sailers Rebuttal, p. 6.
[436] *Id.* at pp. 6–7.
[437] *Id.*
[438] *Id.* at p. 6.
[439] Shenstone-Harris Direct, p. 9.
[440] Sailers Rebuttal, p. 7; Shenstone-Harris Cross, HVR at 7:56:20 (May 11, 2023).
[441] Sailers Rebuttal, p. 7.
[442] *See* Shenstone-Harris Direct, pp. 63–65.
[443] Sailers Rebuttal, p. 7.
[444] *Id.*

is a more reasonable and equitable charge for the collection of the distribution demand revenue requirement among class customers.[445]

Further, Ms. Shenstone-Harris does not fully consider or acknowledge what the Company's tariff offers for customers increasing load at their facilities, such as customers evaluating adoption of an electric vehicle fleet. If the customer is willing to participate in hourly pricing, the Company offers Experimental Real Time Pricing Program (Rate RTP), as filed in this case. Rate RTP would allow a customer to establish a customer baseline load and any incremental load would be priced as a function of PJM's Locational Marginal Price (LMP), with the primary focus being that there are no demand charges associated with incremental load added above the customer's baseline load.

Additionally, while Ms. Shenstone-Harris is correct that EV direct current fast-charging (DCFC) customers may take service on Rate DT,[446] her concerns related to DCFC customers and demand charges do not reflect the fact that DCFC customers are still incentivized to take service on Rate DT to achieve bill savings. DCFC stations are low load factor, so demand charges can certainly be a customer concern.[447] While the Company may consider and discuss rate design alternatives for these types of customers in the future, DCFC station customers remain encouraged, through the Rate DT design proposed, to charge off-peak for significant bill savings.[448] Rate DT is therefore not a barrier to transportation electrification or fleet electrification, contrary to Ms. Shenstone-Harris's claims otherwise.

Finally, it is worth noting that Walmart, an Intervenor in this proceeding and a customer that takes electric service on Rate DT,[449] does not oppose the Rate DT updates proposed in this

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[445] *Id.*
[446] Shenstone-Harris Direct, p. 59.
[447] Indeed, the Commission has a pending proceeding reviewing this issue. Sailers Direct, p. 8.
[448] *Id.*
[449] Chriss Direct, p. 3.

case.[450] In fact, Walmart witness Mr. Chriss states that "[t]he Company's [Rate DT] proposal aligns the distribution rate with how distribution costs are incurred and transparently presents them in the tariff."[451] The Commission should therefore approve the Company's proposed modifications to Rate DT in this proceeding.

e. Load Management Rider (Rider LM)

The Company is also proposing updates to the structure of Rider LM in recognition of potential future customer technology adoption regarding EV charging.[452] Specifically, the Company proposes to add a provision to Rider LM to limit the avoidance of demand charges for off-peak demand by changing the determination of billing demand from only the on-peak period to the higher of the on-peak period demand or 50 percent of the off-peak period demand.[453] This change will apply to Service at Primary Distribution Voltage (Rate DP) and Service at Secondary Distribution Voltage (Rate DS), as those customers taking service on either rate elect to participate in Rider LM.[454] The Company has determined that Rate DP Rider LM participants will experience no revenue impacts from this change, while Rate DS Rider LM participants will experience only immaterial revenue impacts.[455]

Despite the fact that one of the aims of the proposed change to Rider LM is increased future adoption by customers of EVs and the need to charge those EVs, Rider LM is not an EV-specific rate; it is a whole account rate that addresses a customer's entire load.[456] Yet Sierra Club witness Shenstone-Harris focuses her testimony on Rider LM on EV charging independent of all other

[450] *Id.* at p. 5.
[451] *Id.* at p. 20.
[452] Sailers Direct, p. 9.
[453] *Id.* at p. 25.
[454] *Id.*
[455] *Id.* at p. 26.
[456] Sailers Rebuttal, p. 3.

customer load.[457] Ms. Shenstone-Harris's review of Rider LM is also specifically limited to Rider LM participants that are also commercial customers with an EV fleet.[458] She simply does not provide a whole account analysis that accounts for all types of Rider LM participants, as would be appropriate in this case to evaluate the package of impacts that Rider LM will have on participants.[459] If Ms. Shenstone-Harris had performed such analysis, she would have concluded that participation in the proposed Rider LM lowers the customer's bill as compared to Rate DS or Rate DP without Rider LM participation.[460] But she performed and provided no such analyses.[461]

The Company, on the other hand, has.[462] The Company counted the number of bills over a twelve-month period where the customer's on-peak demand was greater than 50 percent of the customer's off-peak demand.[463] Ninety-four percent of Rate DS customer bills had on-peak demand greater than 50 percent of off-peak demand.[464] This suggests that that most customers could add off-peak demand under the Company's proposed change to Rider LM without impact to the customer's demand charges.[465]

Focusing again on EV charging specifically, Ms. Shenstone-Harris also states that including off-peak hours in Rider LM will result in customers paying too much for charging during off-peak hours.[466] This fails to acknowledge that without the changes the Company is proposing in this proceeding to Rider LM, the interaction of Rider LM with Rate DS and Rate DP allows customers to potentially add unlimited off-peak charging load with no impact to the customer's

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[457] *Id.* at pp. 8–9; Shenstone-Harris Direct, p. 66; Shenstone-Harris Cross, HVR at 8:02:36 (May 11, 2023).
[458] Shenstone-Harris Direct, p. 67; Shenstone-Harris Cross, HVR at 8:02:43 (May 11, 2023).
[459] *Id.* at 8:03:23.
[460] Sailers Rebuttal, p. 10; Shenstone-Harris Cross, HVR at 8:04:07 (May 11, 2023).
[461] *Id.*
[462] Sailers Rebuttal, p. 11.
[463] *Id.*
[464] *Id.*
[465] *Id.*
[466] Shenstone-Harris Direct, p. 66.

demand charges.[467] This is potentially inconsistent with principles of cost-causation on distribution substations and feeders that may not peak during typical system peak times. The Company has simply added a provision to Rider LM to limit the increase in off-peak load that is not subject to a demand charge.[468] Through Rider LM, Rate DS and Rate DP customers can increase their off-peak demand to an amount double their on-peak demand before realizing any impact to their demand charge bill component.[469]

The Commission should therefore approve the Company's proposed modification to Rider LM. The Company has provided full analyses that support this change and has demonstrated that current Rate DS and Rate DP customers that also participate in Rider LM will experience little, if any, revenue impacts. Ms. Shenstone-Harris's testimony does nothing to dispute this.

7. Rider ESM Cost Recovery in Base Rates

In its Application, the Company proposed to transfer the recovery of the return on rate base and the related depreciation and property tax expenses from Rider ESM revenues to base revenues for four capital projects.[470] This proposal would increase base revenues by $3.290 million.[471] OAG witness Kollen recommends denial of the Company's request to transfer recovery to base revenues, and the Company does not oppose this recommendation.[472] Mr. Kollen notes that this will reduce the Company's requested base rate increase, but that this reduction is offset by the continued recovery of these costs through the Rider ESM revenue requirement.[473]

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[467] Sailers Rebuttal, p. 9.
[468] *Id.* at p. 10.
[469] *Id.*
[470] Spiller Direct, p. 4; Kollen Direct, p. 41; Duke Energy Kentucky Response to AG-DR-02-040(c).
[471] Steinkuhl Revised Rebuttal, p. 5. This value has been revised several times due to certain calculation errors, but the Company confirms that the base revenue increase associated with this recovery would be $3.290 million. *See* Steinkuhl Cross, HVR at 10:10:04 (May 10, 2023).
[472] Steinkuhl Revised Rebuttal, p. 4; Steinkuhl Cross, HVR at 10:06:48 (May 10, 2023).
[473] Kollen Direct, p. 6.

C. Other Proposed Tariff Changes

1. Clean Energy Connection (CEC) Proposal

Duke Energy Kentucky requests approval of its new CEC program structure and tariff, a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy facilities.[474] The CEC program would allow Duke Energy Kentucky to satisfy increasing customer demand for renewable energy and will enable the Company to provide affordable clean energy to all its customers who want to source their electricity needs from renewable resources.[475] This proposal represents the next evolution of Duke Energy Kentucky's commitment to increasing renewable generation and providing innovative pricing solutions for its customers.[476] The program is structured to maximize the benefits to the entire Duke Energy Kentucky system and to share those benefits with non-participating customers.[477] All solar projects that will come online after approval of the CEC program will require the Company to file an appropriate application in a CPCN proceeding before construction can begin.[478]

The proposed CEC program is well-defined and will present renewable energy opportunities to all of the Company's customers. The Company has sufficiently defined the

[474] *See* Halstead Direct, p. 2.
[475] *Id.*
[476] *Id.*
[477] *Id.*
[478] *Id.* at p. 3.

subscription charge[479] and bill crediting methodology[480] for the CEC program, and has also justified its proposal of the CEC program as a single tariff concept.[481]

OAG recommends denial of the CEC program at this time on the basis that the Company should refile its CEC program when the Company files a CPCN for a solar facility.[482] However, there is no need for the Company to wait to file for approval of the CEC program as part of a CPCN proceeding, and doing so may in fact impede the value that the program offers to customers:

> The Company requested the CEC framework in this case so it can use that tariff as an opportunity to attract interest and engage with customers. Having a tariff and a structure approved now provides certainty to customers who are interested in this type of offering. Having a tariff offering allows the Company to engage directly with customers regarding their renewable strategies with a tool that can assist their desire to have real renewable power satisfying their load requirements.[483]

In addition, the CEC program provides an important tool for keeping and attracting new businesses to Kentucky. Many companies have sustainability goals and approving the CEC program now provides these companies with adequate assurance that they can meet these goals by staying, expanding, or moving to Kentucky.[484]

Additionally, the program will be open to all metered customers, not a select subset of customers.[485] This includes reserved capacity for low-income residential consumers such that even

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[479] Paul L. Halstead Rebuttal Testimony (Halstead Rebuttal), p. 3 (Apr. 14, 2023) ("I stated in my [direct] testimony [that] the subscription charge would be the [net present value of 105 percent of the CEC Program cost less 75 percent of the capital deferral and capacity benefits associated with the underlying assets.").

[480] *Id.* at p. 3 ("Regarding the program's credit, the Company proposes that the bill credit will be sufficient to, and capped at, the amount to generate the forecasted participant payback with all excess provide to non-participating customers. [These calculations, including the subscription charge, provide the framework to ensure non-participating customers are not harmed as well as provide sufficient information for customers interested in renewables to make an informed participation decision. When the CPCN is filed the calculations noted above will be updated to reflect the actual cost.").

[481] *Id.* at p. 4 ("The Company has proposed a single tariff concept in this application. With the exception of the low-income carve-out which is included in the single tariff all customer classes are treated equally and charged the same subscription cost and will receive the same bill credit value. Therefore, one tariff is sufficient.").

[482] Kollen Direct, p. 66.

[483] Halstead Rebuttal, pp, 4–5.

[484] *Id.*

[485] Chriss Direct, p. 23.

customers on government assistance or experiencing financial hardship may source their energy needs from renewable resources.[486] This supports the Company's obligation to provide safe, reliable electric service to its customers in a non-discriminatory manner.

Witness Chriss, presenting testimony on behalf of Walmart—a large commercial customer—suggests that the Commission approve the CEC proposal at this time for a number of reasons.[487] In concluding that the program meets all of the parameters set by Walmart when examining utility programs for renewable energy, Witness Chriss states the following:

> As I described earlier in my testimony, Walmart does not enter into premium structures or programs that only result in additional costs to our facilities. Rather, Walmart seeks renewable energy resources that deliver industry-leading cost, including renewable and project specific attributes such as [renewable energy credits], within structures where the value proposition allows the customer to receive any potential benefits brought about by taking on the risk of being served by that resource instead of, or in addition to, the otherwise applicable resource portfolio. Additionally, Walmart does not enter into programs with terms in excess of 15 years. [The Company's] proposed CEC Program meets all of these parameters.[488]

Walmart's interests in CEC are reflective of the views of many of the Company's other customers.[489] This program provides a reasonable strategy to meet these customers where they are, and potentially attract more similarly-situated customers interested in renewable energy opportunities.[490] Indeed, a similar CEC program has shown success in a Company affiliate's service territory.[491] The Company therefore urges the Commission to approve this program.

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[486] *Id.* at p. 24; Halstead Direct, p. 7.
[487] Chriss Direct, p. 25.
[488] *Id.* at p. 26.
[489] Halstead Rebuttal, p. 2.
[490] *Id.*
[491] This Company affiliate is Duke Energy Florida, LLC (Duke Energy Florida), which has its own CEC program in place. *See* Halstead Direct, p. 3; Halstead Rebuttal, pp. 5–6.

2. Local Government Fee Tariff Modifications

Duke Energy Kentucky has proposed updates to its Local Government Fee Tariff to clarify its use and application compared to the Incremental Local Investment Charge Rider (Rider ILIC), a new rider the Company is proposing in this case.[492] The Local Government Fee addresses a cost or fee that a locality may assess directly on the Company—for example, a franchise fee.[493] Rider ILIC, however, is proposed to address a material cost or investment that the locality imposes on the Company through requirements embedded in a franchise or ordinance.[494] Clarifying language to this effect has been added to the Local Government Fee Tariff. Rider ILIC is discussed in further detail below.

3. EV Rates Proposals

As part of a package of EV programs and associated tariffs proposed in this proceeding, the Company is proposing the Electric Vehicle Site Make Ready Credit (MRC) program and the Electric Vehicle Service Equipment (EVSE) Program.[495] Significant state-wide financial benefits are possible from increased EV adoption.[496] Further, savings to all customers—not just EV users[497]—are anticipated to result from increasing EV adoption due to incremental net revenue received by selling electricity to charge EVs in excess of any increases in costs of service related to the additional load.[498] To unlock this potential, the Company's proposals in this case focus on simplifying EV adoption for Kentucky customers.[499] These two proposals are described in further detail below.

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[492] Sailers Direct, p. 29.
[493] *Id.*
[494] *Id.*
[495] Gordon Direct, p. 3.
[496] *Id.* at p. 4
[497] Gordon Cross, HVR at 9:13:07 (May 10, 2023).
[498] Gordon Direct, p. 4.
[499] *Id.* at p. 5.

a. MRC Program

The proposed MRC program will be available on a voluntary basis to residential and non-residential customers at their premises or places of business that require improvements (*i.e.*, make ready infrastructure) to prepare for installation of a Level 2 or higher EV charger.[500] The credit associated with the program is designed to defray customer installation costs associated with EV chargers to encourage mutually beneficial EV adoption.[501] While a program of this type is not mandated in Kentucky, the Company maintains that there are a number of compelling reasons to deploy a program that simplifies EV adoption for customers who are otherwise prevented from doing so due to lack of capital or discomfort with complicated electrical installations.[502] This includes low-income customers.[503]

As designed, the program was also conceived to benefit all ratepayers, not just those that adopt EVs, and the Company therefore has proposed recovering program costs from all customers.[504] Any concerns related to cost recovery from non-program participants are defrayed by the cost offset of future EV charging revenues that will eventually result in downward rate pressures that will benefit *all* ratepayers. It is also implausible to recover costs only from program participants while maintaining the benefits of the program, of which there are many.[505] Recovery of program costs from all customers is therefore appropriate given the proposed program's structure.[506]

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[500] *Id.* at p. 6.
[501] *Id.*
[502] Cormack C. Gordon Rebuttal Testimony (Gordon Rebuttal), p. 5 (Apr. 14, 2023).
[503] *Id.* at p. 9.
[504] Gordon Direct, p. 3; Gordon Rebuttal, p. 8.
[505] *Id.*
[506] OAG witness Kollen's recommendation regarding cost recovery from program participants only is therefore unsupported. *See* Kollen Direct, pp. 59–60.

The Company has also proposed approval to defer the costs of the MRC program for future recovery.[507] The costs for which the Company is seeking to create this regulatory deferral constitute an expense in relation to an industry-sponsored initiative in support of a statutory directive to expand the electrification of vehicles across the country.[508] No party to this case has provided any compelling or substantive rationale for denying the Company this deferral authority.[509] This Commission should therefore authorize the Company to defer these costs for future recovery.

In fact, several Intervenor witnesses to this proceeding have indicated that they support approval of or do not oppose the MRC program.[510] While Walmart witness Chriss indicated in this proceeding that there were concerns related to adequate consumers data protections in the proposed tariff language,[511] the Company provided extensive information in rebuttal testimony indicating that appropriate consumer data protections would be contained in the program terms and conditions.[512] The Company also follows standard operating procedures, which include the Company's commitment to not release data without appropriate customer consent.[513] Nonetheless, Company witness Gordon also provided assurances that the Company would evaluate whether additional revisions to the program terms and conditions were appropriate.[514] Walmart's concerns therefore should be resolved.

[507] Lawler Rebuttal, p. 29.
[508] *Id.* at p. 30.
[509] *Id.* at p. 29; *see also* Kollen Direct, p. 60.
[510] *See* Chriss Direct, p. 26 ("Walmart generally supports the approval of the Company's make ready program and Rate MRC."); Kollen Direct, p. 7 (indicating that he does "not oppose" the MRC program).
[511] Chriss Direct, p. 27.
[512] *See* Gordon Rebuttal, pp. 3–4.
[513] Gordon Cross, HVR at 9:15:46 (May 10, 2023).
[514] *Id.* at 9:19:17.

Finally, the Company notes that it designed the MRC program to work in tandem with its proposed EVSE program,[515] discussed in further detail below. The Company designed complementary programs that work together but are distinct from one another.[516] Contrary to OAG's assertions, there is no compelling evidence in this case that shows that combination of the MRC program with the EVSE program will result in the same customer benefits.[517] Administration of the programs would also be compromised, as adding a make ready component to the EVSE program would significantly complicate program delivery by requiring the Company to participate in the market in ways that limit customer choice.[518] Most notably, the MRC residential Customer Option, Non-Residential and Homebuilder options could not exist as designed, thus limiting MRC customer autonomy when participating.[519]

As such, the Company maintains its proposal of the MRC program as a standalone program to benefit all customers. The EVSE program retains its own beneficial characteristics and, in conjunction with the MRC program, will provide a broad array of benefits to EV and non-EV customers alike.

b. EVSE Program

The EVSE program will also be available on a voluntary basis and will provide both residential and non-residential customers with the ability to choose a Level 2 or higher EVSE to have installed at their home or business.[520] While Duke Energy Kentucky will install and own the charging equipment, customers will operate it on a day-to-day basis according to their own unique needs.[521] Once installed, the customer will pay a flat rate each month for that charger for the term

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[515] Gordon Rebuttal, p. 7.
[516] *Id.*
[517] *Id.*; *see also* Kollen Direct, p. 60.
[518] Gordon Rebuttal, p. 7.
[519] *Id.*
[520] *Id.* at p. 3.
[521] *Id.*

of the contract with the Company. Included in the monthly rate amount is the charger and related installation, maintenance, and warranty work. Participating customers will be responsible for any energy use, which will be billed at standard, approved rates, as well as any make ready work that may be necessary prior to installation.[522]

As noted above, the EVSE program complements the MRC program and will provide benefits to the Company's entire customer base. There is no compelling reason to combine the EVSE and MRC programs, as the benefits provided to customers may be lost and costs increased as a result.[523] Additionally, no Intervenor in this proceeding conceptually opposes approval of this program.[524] The Company therefore requests that the Commission approve the proposed EVSE program.

D. Other Issues

1. Comprehensive Hedging Program

As part of this proceeding, Duke Energy Kentucky is proposing to implement a comprehensive hedging strategy. This comprehensive hedging proposal is proposed for the Company's electric generation portfolio to mitigate market volatility for customers in the Fuel-Adjustment Clause (FAC), optimize the market dispatch of the Company's fossil-fueled generation in PJM, and in the procurement of replacement power.[525] The Company is proposing this proactive program change because spot market power prices have been volatile since the Company joined PJM markets in 2012,[526] and locking in price certainty for customers helps reduce customer exposure to FAC volatility.[527]

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[522] *Id.* at pp. 3–4.
[523] *See* Gordon Rebuttal, p. 7.
[524] *See* Kollen Direct, pp. 7, 60 (noting that he does not oppose approval of the EVSE program, and indeed supports it if combined with the MRC program).
[525] McClay Direct, pp. 2–3 (Dec. 1, 2022)
[526] *See id.* at p. 18.
[527] *Id.* at pp. 18–19; McClay Cross, HVR at 8:08:32 (May 9, 2023).

The Company has provided a detailed and informative description of the comprehensive hedging proposal. Using the PJM AD Hub financial forward power markets that have available financial products to hedge exposures for monthly, weekly, and daily terms, the Company proposes to expand customer exposure price risk mitigation to include scheduled outages and derates, forced generation outages and derates, and time periods where market prices are lower than operating the Company's owned generation assets.[528] Using the financial markets when generation costs exceed market prices reduces customer costs, locking in economic price certainty, while forward financial hedging reduces customer exposure to daily spot market volatility during forced and scheduled outage and derate periods.[529] The Company proposes a hedge horizon of a rolling one-year time period.[530] Based on the type of exposure being mitigated, financial power hedges can be executed over time to lock in power prices and minimize exposure to the volatile spot market price movements for scheduled and forced outages.[531] The Company's proposal is therefore comprehensive, and the Company has provided the scope of the hedging proposal, hedge methodology, hedging horizon limit, and hedge products that would be used to mitigate volatility and provide price certainty to protect customers.[532]

Proactive financial and economic hedging also benefits customers. During forced and scheduled outage or derate periods Duke Energy Kentucky has proprietary specific knowledge and can protect the customers from future market volatility. From time to time, economic financial hedges can lower costs for customers by leveraging market prices when Duke Energy Kentucky's expected dispatch costs exceed market prices.[533] Indeed, hedging activities may result in net fuel

[528] McClay Direct, p. 17.
[529] *Id.*
[530] *Id.*
[531] *Id.*
[532] James J. McClay Rebuttal Testimony (McClay Rebuttal), pp. 2–3.
[533] McClay Direct, p. 18.

cost savings.[534] Furthermore, a balanced and comprehensive fuel price risk management approach results in greater fuel cost certainty to customers' benefit.[535]

The Company's proposed hedging plan also aligns with the Commission's order from Case No. Case 2021-00086. There, the Commission ordered the Company to evaluate whether there is a need for a back-up power supply plan and to provide a long-term cost-effectiveness analysis of its back-up power supply plans.[536] Since its first back-up power supply plan was filed with the Commission, the Company has continued to evaluate various hedging strategies and determine how best to balance cost and customers' exposure to market price risk.[537] The Company has provided this information and evaluation as part of the record in this case.[538] The Company has also properly proposed this program for approval in this case. Because the goal of the hedging program is to manage the market price impact for purchased power and mitigate volatility in customers cost, power hedging and economic power purchases have a direct impact on how much customers pay for power usage.[539] The Company therefore believes that this program should be a part of this rate case proceeding, as waiting for a separate case only serves to lengthen customers' exposure to volatility in the energy markets.[540]

The Commission may thus consider and approve the proposed program in this case, and the Company urges it to do so. Commencing a proactive comprehensive power financial hedging program and enabling economic purchases when the market price is less than the cost of generating power provides immediate benefits to customers given the number of risk factors that can impact

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[534] *Id.* at p. 20; *see also* McClay Rebuttal, pp. 3–4.
[535] McClay Direct, p. 20.
[536] Kollen Direct, p. 67.
[537] McClay Rebuttal, p. 4.
[538] *See generally* McClay Direct; McClay Rebuttal; McClay Examination, HVR at 8:10:11, 8:11:20 (May 9, 2023)
[539] *Id.* at p. 5.
[540] *Id.*

prices and trends.[541] A comprehensive hedge program that includes flexibility to hedge forced and scheduled outage and derate periods provides price certainty and limits customer exposure to spot price volatility. In addition, the ability to purchase more economical financial power resulting in lower customer costs is prudent and in customers' best interest.[542]

2. Rider FAC Modifications

Duke Energy Kentucky has proposed modifications to its Rider FAC to reduce monthly volatility on customer bills. Volatility in retail rates can be a common source of customer complaints,[543] so the Company's proposed updates to Rider FAC will likely improve customer satisfaction and reduce customer complaints related to volatility in electric rates.[544]

In accordance with 807 KAR 5:056, the Company currently recovers its actual fuel costs attributable to serving its retail load through a combination of amounts recovered in base rates and Rider FAC.[545] As the mechanism operates now, the Company calculates the cost of fuel burned in its generating facilities and any energy purchased in the market attributable to its retail load.[546] The total cost of burning fuel and purchasing energy for its retail load in that month is divided by the actual kilowatt-hour (kWh) sales during that same month.[547] The result is a rate that is compared to the fuel and purchased power rate included in base rates.[548] The difference in the two rates is then recovered via Rider FAC and billed to customers in the upcoming month.[549] Due to monthly fluctuations in billed sales and changes in actual fuel and purchased power costs, Rider FAC contains a true-up provision whereby the rate is adjusted to ensure that the Company recovers

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[541] *Id.* at p. 6.
[542] *Id.*
[543] Lawler Direct, p. 14.
[544] *Id.* at p. 17.
[545] *Id.* at p. 11.
[546] *Id.*
[547] *Id.*
[548] *Id.*
[549] *Id.*

no more and no less than its actual cost of providing electric generation service to its retail customers.[550]

However, the current Rider FAC mechanism—whereby the rate is calculated on a monthly basis—frequently results in significant variances on customer bills from month to month.[551] This is due to a combination of the Company's limited generation portfolio (namely, East Bend and Woodsdale) and the need to supplement with energy purchased on the PJM market, which can be quite volatile.[552] Because the calculated Rider FAC rate is currently billed in the following month and seasonal changes in demand vary retail load significantly from month to month, the current month-to-month calculation and billing mechanism can produce a significant over- or under-recovery of the FAC that, in turn, influences the Rider FAC calculation in future months.[553] This volatility can be extremely frustrating for customers.[554]

As such, the Company is proposing to change its calculation of the Rider FAC rate to a rolling twelve-month average basis.[555] This minor change will reduce month-to-month bill changes for customers by providing a steadier, more modest increase in their monthly bills due to fuel and purchased power costs.[556] With this proposed calculation methodology, customers will benefit from avoiding what can be unpleasant surprises on their monthly bills.[557] Further, the Commission's authority to examine the Company's fuel procurement and FAC rate calculations will be unaffected.[558] Notably, OAG witness Kollen recommends that the Commission approve

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[550] *Id.* at p. 12.
[551] *Id.*
[552] *Id.* at pp. 13–14.
[553] Lawler Direct, p. 14.
[554] *Id.*
[555] *Id.*
[556] *Id.* at p. 16; *see also id.* at p. 15 (depicting the proposed calculation change versus the monthly calculation basis for Rider FAC for 2021 and 2022 data, and showing that the proposed change will significantly smooth out the monthly Rider FAC rate).
[557] *Id.* at p. 16.
[558] *Id.*

these changes to Rider FAC, noting that this proposal "affects only the timing of the FAC recoveries; it does not affect the amounts eligible for FAC recovery."[559]

The Company therefore requests that the Commission approve these proposed updates to Rider FAC. Customers will benefit from reduced volatility on their monthly bills, and the Company will benefit only in terms of increased customer satisfaction with Company operations and billings.[560]

3. Rider ILIC

The Company is proposing a new surcharge mechanism, Rider ILIC, and a related process to ensure appropriate cost recovery for incremental system investments required pursuant to a local ordinance or franchise.[561] The need for Rider ILIC has been brought on by recent developments in and requests and directives from municipalities and local authorities within the Company's service territory.[562] In recent years, localities in the Company's service territory have begun to request or require, by local regulation, certain actions by the Company that fall outside of the Company's regular system-wide construction plans.[563] Indeed, localities have become "emboldened in what they are requesting of utilities,"[564] and are beginning to request—or, in some cases, require—that the Company undertake "extraordinary measures" within their jurisdictional borders.[565] This includes undergrounding all electric facilities within a municipality's borders within three-years, a measure which is indeed extraordinary and inconsistent with the Company's standard service.[566] Under Rider ILIC, the Company is proposing a process such that when the Company becomes

[559] Kollen Direct, pp. 5–6.
[560] Lawler Direct, p. 17.
[561] Spiller Direct, pp. 27, 31.
[562] Lawler Direct, p. 21.
[563] *Id.*
[564] Spiller Examination, HVR at 1:03:09 (May 9, 2023).
[565] *Id.* at 1:02:00.
[566] *Id.*

obligated, at the direction of a locality, to make an investment or incur a specific cost that is outside of the Company's normal operations or planning, the Commission will determine whether such a charge will be included on all customer bills or only on the bills of those customers within the boundaries of the locality imposing the costs.[567]

Such a rider is necessary given the increasing frequency with which localities are imposing extreme requirements on the Company outside of the Company's normal operations and service.[568] Rider ILIC will ensure timely and appropriate cost recovery from the appropriate customer group and will be subject to Commission oversight to the same extent the Commission presently exercises jurisdiction over the Company's rates and services.[569] Rider ILIC rates would require Commission approval, similar to pipeline replacement mechanisms and amendments to environmental surcharge mechanisms that operate before the Commission today.[570] This regulatory mechanism is therefore familiar and subject to appropriate Commission regulation; this mechanism does not constitute "self-regulation" of any sort.[571]

Additionally, the Company will continue, as it has done in the past, to negotiate with localities imposing costs that would be subject to Rider ILIC.[572] The Company retains its obligation to prudently incur costs regardless of whether Rider ILIC is approved and implemented, and the Company therefore retains its incentive to negotiate with localities to the benefit of the utility customers it serves. As such, the Company will continue to discuss the impact of a proposed action with those localities—whether by local ordinance, franchise, or a similar mechanism—and whether that action is practical and feasible.[573]

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[567] Spiller Direct, p. 31.
[568] Spiller Examination, HVR at 1:02:00, 1:03:09 (May 9, 2023).
[569] *Id.* at 1:04:25 (May 9, 2023); Lawler Direct, p. 21; Lawler Rebuttal, pp. 25–26.
[570] *Id.*
[571] *Id.*
[572] *See* Spiller Examination, HVR at 1:03:34 (May 9, 2023).
[573] *See id.*

Duke Energy Kentucky therefore requests that the Commission approve the Rider ILIC tracker mechanism, recognizing that the Commission retains its oversight over the costs actually charged to customers under the Rider in the future, if any.

4. Late Payment Charges

Duke Energy Kentucky has proposed a late payment charge to customers of 2.3 percent of the net monthly bill, a considerable decrease from the Company's current late payment charge of 5 percent of the net monthly bill.[574] Notably, this proposed percentage charge is charged on a late payment only once, so customers will not be charged a compounding 2.3 percent on their total arrears.[575] This reduced percentage more closely reflects the Company's current average of incremental costs related to late paying customers,[576] and results from three incremental cost drivers: carrying costs of unpaid bills, outbound customer delinquency communications, and customer service costs (for example, inbound calls for installment plans).[577] The Company provided formal cost support for this proposed charge as part of its Application.[578]

This charge is proposed as a percentage of a customer's net monthly bill (versus a fixed charge that does not vary with the size of the customer's bill) for several reasons. A late payment charge that varies with the size of a customer's bill more closely reflects the incremental benefit to the customer that does not pay its bill on time and more fairly allocates late payment charges among customers with varying usages.[579] In this instance, if a fixed charge were imposed, late-paying customers with lower usages (*i.e.*, smaller bills) may effectively subsidize late-paying customers with higher usages (*i.e.*, larger bills), as each customer set would pay the same late

[574] Colley Direct, p. 14.
[575] Colley Examination, HVR at 7:38:36 (May 10, 2023).
[576] Colley Direct, p. 14.
[577] *Id.*
[578] *See id.* at JSC-1, p. 1.
[579] *See* Colley Examination, HVR at 7:45:00 (May 10, 2023).

charge, but the customers with higher usages would receive more incremental value in using more service per month.[580] This concept is supported by the cost drivers shown in the formal cost support provided as part of the Application, as carrying charges vary with the size of the bill,[581] and customer service costs can reasonably vary based on the size of the bill,[582] and these two cost drivers collectively account for nearly 95 percent of the incremental costs to the Company related to late paying customers.[583] Additionally, this percentage-based charging method is generally consistent with the practices of Duke Energy Kentucky affiliates and other utility tariffs across the industry.[584]

The proposed late payment charge of 2.3 percent of the net monthly bill is therefore well-supported, and is indeed over 50 percent less than the Company's current late payment charge. As such, the Company requests that the Commission approve the proposed late payment charge.

5. Customer Service and Payment Locations

Duke Energy Kentucky offers a variety of options for customers to pay their utility bills.[585] In additional to online, automatic bank draft, and mobile application payment options, the Company offers over fifty in-person payment locations in its service territory via its Pay Agent Network.[586] These locations offer a variety of payment options (*e.g.*, cash, check, credit card, debit card) and remit customer payments directly to Duke Energy Kentucky.[587]

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[580] *See id.*
[581] *See id.* at 7:39:38
[582] *See* Colley Redirect, HVR at 7:53:17 (May 10, 2023) (noting that customer service costs may vary with the size of the customer's bill).
[583] *See* Colley Direct at JSC-1, p. 1 (indicating that the average monthly carrying cost per late paying account is $0.85, that the average monthly customer service call cost per late paying account is $1.43, and that the total average monthly cost per late paying account is $2.42).
[584] *See* Colley Examination, HVR at 7:47:36 (May 10, 2023).
[585] *See* Spiller Direct, pp. 18–19 (summarizing bill payment options for Duke Energy Kentucky customers).
[586] *Id.* at p. 19.
[587] Colley Cross, HVR at 7:12:13 (May 10, 2023).

While most of these locations may charge a processing fee for certain payment types, these processing fees are charged directly by the third-party processor and are never remitted to the Company, and therefore are never passed on to customers via rates or any other mechanism.[588] Additionally, there is at least one location in the Company's service territory that accepts bill payments without any additional processing or other add-on fees.[589] Customers can locate in-person payment locations by using the payment location search function on the Company's website, and can additionally locate fee-free in-person payment options using a filtering functionality within the website search function.[590]

The Company continues to keep its customers' needs at the forefront of its business and therefore regularly engages in intra-Company discussions related to its fee-free payment location options and its overall customer service offerings.[591] Notably, the Company's President has not received any negative feedback related to the Company's fee-free in-person payment offerings.[592] Per Commission regulations, the Company also maintains an in-person facility in Erlanger, Kentucky where customers can review the Company's current tariffs and proposed tariffs in this case, as well as its system maps and records.[593] While customers have remote access to a number of customer service opportunities,[594] Company representatives at the Erlanger facility may also be able to assist customers looking for in-person customer service as needed.[595]

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[588] *Id.* at 7:23:14.
[589] *See id.* at 7:17:21 (noting that while at the time of the Hearing, there was one fee-free in-person payment option in the Company's service territory, the list of fee-free in-person payments options is dynamic and may evolve over time depending on various venders' arrangements with the Company).
[590] *Id.* at 7:16:18 (May 10, 2023).
[591] *Id.* at 7:21:19.
[592] Spiller Examination, HVR at 6:14:22 (May 11, 2023).
[593] Spiller Examination, HVR at 1:10:46 (May 9, 2023).
[594] *See* Spiller Direct, p. 13 (describing a variety of customer service channels available to Company customers).
[595] Colley Cross, HVR at 7:13:15 (May 10, 2023).

Customers may therefore currently avail themselves of a number of different customer service and payment options, including in-person options. In addition, the Company continues to evaluate the most effective ways to provide its customers with safe and reliable electric service, as well as efficient customer and payment services, and will continue to do so in the future.

6. Kroger's Proposed Multi-Site Aggregation Commercial Rate

Kroger's proposed Multi-Site Aggregation Commercial Rate is ill-conceived, as it would shift (*i.e.*, increase) demand charges from larger multi-site customers to comparatively smaller customers with single sites and would be administratively infeasible for the Company to implement. As such, Duke Energy Kentucky opposes this proposed rate and requests that the Commission deny Kroger's recommendation.

Kroger witness Mr. Bieber describes the concept of a multi-site aggregation program:

> A multi-site commercial rate aggregation program would allow eligible customers with multiple service locations to aggregate their demands for purposes of production and transmission billing. For a multi-site aggregation program, the billing demand is measured as the highest hourly demand occurring simultaneously across each of a customer's participating locations, thereby measuring billing demand for the totality of the customer's participating sites as if it were a single load for billing purposes. This is described as conjunctive demand billing and should only apply to a customer's generation and transmission service. The distribution portion of the bill should be calculated using demand billing determinants established separately at each location.[596]

As proposed, such a program would only be available to utility customers with multiple service locations, which Kroger witness Bieber agrees are typically a utility's larger customers.[597]

This proposed program benefits larger customers to the detriment of smaller customers. If multi-site customers are allowed to aggregate their maximum kilowatt (KW) demand, the conjunctive billing demands of those customers would generally be less than the sum of each

[596] Bieber Direct, pp. 14–15.
[597] Bieber Cross, HVR at 3:12:10 (May 10, 2023).

individual site's demands.[598] Multi-site customers would therefore generally have lower billing demands.[599] All other things remaining equal, these lower billing demands necessarily would result in a higher dollar-per-KW charge for customers with single sites.[600] As a result, this program would inappropriately and unfairly favor a utility's larger customers. It may also constitute discrimination in that a group of customers under the same ownership is treated differently than all others.[601] Kroger witness Bieber notably agreed with this line of reasoning at Hearing.[602] While Mr. Bieber does not necessarily propose that the Company be required to implement a multi-site aggregation program after this case, his recommendation that the Company be required to study the potential benefits of such a program is unnecessary and infeasible in light of the analysis provided above.

That said, there are additional administrative burdens that study and implementation of such a program could impose on the Company that Mr. Bieber failed to evaluate. Mr. Bieber is generally unfamiliar with the Company's billing system, and has not performed any analysis to determine what changes would be required to the Company's billing system to study and potentially implement the proposed rate—much less whether those changes are even feasible.[603] The Company should not be required to undertake any study or analysis related to a multi-site aggregation program that Kroger's own witness did not undertake himself, particularly in light of the discrimination issue inherent in the proposed program as discussed above.

Finally, Kroger's proposed program fails to consider existing energy efficiency programs available to the Company's commercial customers. These programs, which the Company already has in place, serve to help commercial customers reduce their peak demands, which reduces those

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598 *Id.* at 3:12:44.
599 *Id.* at 3:13:02.
600 *Id.* at 3:13:16.
601 *See* Bieber Examination, HVR at 3:28:10 (May, 10, 2023).
602 *See* Bieber Cross, HVR at 3:12:44 (May 10, 2023).
603 *Id.* at 3:14:57.

customers' bills in a manner similar to the proposed multi-site aggregation program.[604] Commercial customers may also take advantage of the Company's non-residential TOU, which Kroger witness Bieber admits allow non-residential customers to reduce their electric bills by shifting demand from on-peak to off-peak periods.[605] These mechanisms have the same effect on commercial customers' bills as the program Kroger is proposing.

Thus, Duke Energy Kentucky opposes Kroger's recommendation that the Company be required to study the potential benefits of such a program as part of its next rate case. The inherent discriminatory nature of the proposed program, coupled with the lack of clarity regarding the feasibility of even studying such a program—much less implementing it—counsel against approval of this recommendation. Existing programs made available to customers like Kroger are sufficient to allow those customers to reduce their demand charges and utility bills.

7. Generation Asset True-Up Mechanism (Rider GTM) Proposal

In its Application, the Company proposed Rider GTM, a placeholder rider intended to reconcile final recovery of any undepreciated plant related to the Company's generation portfolio (including East Bend and Woodsdale) that may remain at the time of retirement.[606] As explained in further detail above, the Company is proposing approval of updates to its depreciation rates to align the depreciable lives of its generation assets with their service lives. Rider GTM would recover that undepreciated plant related to these assets that was not able to be recovered due to the timing of the Company's incremental investments and base rate cases.[607]

[604] *Id.* at 3:15:45.
[605] *Id.* at 3:16:14.
[606] Spiller Direct, p. 27.
[607] *Id.* at p. 29.

In March 2023, after the Company filed its Application that proposed Rider GTM as a placeholder mechanism, Kentucky Senate Bill 4 was enacted.[608] SB 4 established a three-part test that the Commission must evaluate and determine is satisfied before authorizing either the retirement of a fossil-fuel-fired generating unit, a decommissioning surcharge, or recovery of retirement costs.[609] The Company has determined that Rider GTM is likely subject to the mandates of SB 4. Because the Company's Application did not and could not have addressed the three-part test outlined in SB 4 as it relates to the Company's generating assets, the Company has determined that Rider GTM cannot be approved as part of this case.[610] The Company confirmed this view in rebuttal testimony,[611] and reiterates it here.

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 $68.82 million using a valuation based upon rate base and an ROE of 10.35 percent;

B. The Company's rate base shall be approved as filed except for the adjustments agreed to by Duke Energy Kentucky in rebuttal testimony;

C. The Company is authorized to amortize and recover its planned generation maintenance outage expense, forced outage purchased power expense, each over a five-year period;

D. The Company shall continue amortizing the East Bend deferred O&M expense in base rates and the East Bend coal ash ARO regulatory asset through Rider ESM over the ten-year

608 Lawler Rebuttal, p. 3.
609 *Id.* at p. 6.
610 *Id.*
611 *See Id.*

period approved by the Commission in Case No. 2017-00321;

E. The Company's depreciation rates, which include appropriate decommissioning expense as part of those rates, for East Bend and Woodsdale shall be approved as provided for in the Application, and said depreciation rates shall be aligned with projected retirement dates of 2035 for East Bend and 2040 for Woodsdale;

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 2019 Rate Case as provided for in the Application;

G. The Company is authorized to implement and manage its proposed capital structure as revised by the Company in rebuttal testimony, including an authorized equity ratio of 52.145 percent;

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

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

J. The Company's proposed Rate RS-TOU-CPP and Rider ILIC shall be approved as provided for in the Application;

K. The Company's updates and modifications to its Rate DT, Rate DPA, Local Government Fee Tariff, Rider LM, and Rider FAC shall be approved as provided for in the Application;

L. The Company's proposed CEC program, MRC program, and EVSE program shall be approved as provided for in the Application;

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

N. The Company's reduced late payment customer charge shall be approved as provided for in the Application;

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

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

This 9th day of June 2023.

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document in paper medium; that the electronic filing was transmitted to the Commission on June 9, 2023; 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.[612]

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