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 PETITION FOR REHEARING

Comes now Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company), by counsel, pursuant to KRS 278.400 and other applicable law, and does hereby petition the Kentucky Public Service Commission (the Commission) to grant rehearing on certain items contained in the Commission's October 12, 2023 Order (Order), respectfully stating as follows:

I. INTRODUCTION

Duke Energy Kentucky filed its Application for Authority to Adjust Electric Rates, Approval of New Tariffs, Approval of Accounting Practices to Establish Regulatory Assets and Liabilities, and for All Other Required Approvals and Relief on December 1, 2022 (Application), seeking a $68.82 million increase in its electric base rates.[1] In its Order dated October 12, 2023, the Commission granted an electric base rate increase of $47.498 million. While Duke Energy Kentucky appreciates the time and attention the Commission put into reviewing the Company's Application, the Company respectfully suggests that, in several key aspects, the Order is based

[1] While the Application initially sought a $75.177 million increase in electric base rates, the Company later revised this amount to $68.82 million. *See* Lisa D. Steinkuhl Revised Rebuttal Testimony (Steinkuhl Revised Rebuttal), 7 (May 5, 2023).

upon incorrect assumptions, analyses, or understandings and thus arrives at certain conclusions that are inconsistent with the evidence in the record, underlying authorities, or both.[2] It is therefore necessary and appropriate for the Commission to grant rehearing on the issues set forth herein. The Company also respectfully raises certain clarifications or corrections of a more clerical nature to the Order in this case.

II. ARGUMENT

A. Appendix B Rates

At the outset, Duke Energy Kentucky notes that the rates prescribed in Appendix B, which the Commission approved as "fair, just and reasonable rates,"[3] may not reflect the adjustments described by the Commission earlier in its Order. If true, customers will benefit from a reconciliation of Appendix B with the adjustments made by the Commission, as customer rates may be reduced from those currently shown.

Upon review, it appears that the Commission may have applied the approved increase in revenues to the incorrect "current rates" or "current revenues" in Schedule M to the Application in determining the rates and charges shown in Appendix B to the Commission's Order. Specifically, it appears the Commission may have started with the "current revenues" that included the Rider Environmental Surcharge Mechanism (ESM) components originally proposed for roll-in to base rates. While the Company's Application originally 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 in-service capital projects,[4] a witness for the Office of the

[2] KRS 278.400 establishes the standard of review for motions for rehearing and limits rehearing to new evidence not readily discoverable at the time of the original hearings, to correct any material errors or omissions, or to correct findings that are unreasonable or unlawful.

[3] Order, 87.

[4] Amy B. Spiller Direct Testimony, 4 (Dec. 1, 2022); Lane G. Kollen Direct Testimony (Kollen Direct), 41 (Mar. 10, 2023); Duke Energy Kentucky Response to AG-DR-02-040(c).

Attorney General (OAG) recommended denial of this roll-in,[5] and the Company did not oppose this recommendation.[6] The Commission agreed with the OAG and denied the roll-in proposal, reducing the Company's forecasted test year revenue requirement increase by $3.290 million.[7]

However, the rates and charges shown in Appendix B appear to have been calculated using the approved increase applied to the Company's "current revenues" without removal of the proposed (but denied) Rider ESM roll-in. The amount of Rider ESM revenues included in the Company's "current revenues" was $6.638 million.[8] The Company can see that the final rates do not match what the Company would anticipate based on the other decisions in the Order; however, because the Company does not have access to workpapers of the Commission or its Staff, it is unable to confirm if such an error was made. If indeed the aforementioned error was made, the Rider ESM components that the Commission held should not roll into base rates, but rather be left in the Rider ESM, should be removed from the "current revenues" in Schedule M of the Application for purposes of calculating the final rates in Appendix B of the Commission's Order. The rates and charges presented in Appendix B will then be slightly lower than those listed in the current Appendix B, which were already approved as reasonable in the Commission's Order. The Company requests that the Commission review this discrepancy to determine if indeed such an error occurred, and, if necessary, reconcile and revise Appendix B to reflect the revenues, rates, and adjustments prescribed in the body of the Commission's Order.

[5] Kollen Direct, 6.

[6] Duke Energy Kentucky Initial Post-Hearing Brief (Brief), 71 (June 9, 2023); Steinkuhl Revised Rebuttal, 4; Steinkuhl Cross, HVR at 10:06:48 (May 10, 2023).

[7] Order, 10–11.

[8] Duke Energy Kentucky Revised Supplemental Response to STAFF-DR-03-021.

B. On-Site Payment Location

The Commission's requirement that Duke Energy Kentucky "maintain an office that is open five days a week for a total of 40 hours each week in which customers can make payments without having to pay a service fee"[9] would be extremely cost-inefficient and burdensome to implement insofar as it requires such an office in Kentucky.[10] However, the Company is able and willing to provide a number of additional fee-free payment locations with longer operating hours, weekend service, and more convenience throughout its service territory. The Company therefore requests that the Commission reconsider its requirement that a fee-free payment location be at a Company-maintained office in Kentucky.

Specifically, the Company is able and willing to arrange for multiple Kroger grocery stores to accept customer payments free of charge. These Kroger grocery stores will be located throughout the Company's service territory and typically operate ten hours a day, seven days a week (*i.e.*, more than the forty hours, five days a week stated in the Commission's Order). These Kroger payment centers will be able to accept payments, communicate account balances, and provide customers with payment amounts needed to avoid disconnection. For additional inquiries, these payment centers will be able to direct the customer how to contact the Company directly to discuss installment plans or and other account-specific questions. By establishing these additional fee-free payment options, the Company can meet the spirit of the Commission's desire in a very cost-effective manner for customers while still providing superior customer convenience.

Even if it was possible to modify the Erlanger location to become a walk-in payment processing center—which, for the reasons explained below, it is not—the Company's proposal

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[9] Order, 44.

[10] The Company currently accepts Kentucky customers' payments in its Cincinnati, Ohio office location, where it is also able to provide customer service to those customers, such as negotiating payment plans, etc. Colley Cross, HVR at 7:13:15 (May 10, 2023).

above would provide more locations, longer hours, and the convenience of being co-located with a major grocery and pharmacy in commercial areas, as opposed to being located in a business park like the Erlanger facility. Insofar as the Commission noted that the Company could meet its originally stated requirement by "making arrangements to accept customer payments at its Erlanger facility,"[11] the possibility of doing so was not explored in the record. If it had been, the Company would have demonstrated that adding the necessary infrastructure to the Erlanger facility would be impracticable—if not impossible—and at a significant cost not contemplated or accounted for in the test year of this case.

The Erlanger facility is not currently capable of providing walk-in customer service of this kind and it could not easily, efficiently, or practically be converted to do so, as it is currently being used to its capacity for electric and natural gas utility operations. The facility does not have the room to renovate the existing facility or the excess property to expand the facility to safely accommodate a full walk-in payment processing center. The personnel onsite at the Erlanger facility are engaged in the utility's electric and natural gas delivery functions and are not trained to accept or process customer payments. While some of these employees have administrative responsibilities, the job responsibilities for these employees are to support the Company's electric and natural gas delivery operations. Although these personnel are available to assist customers wishing to review the Company's filings and tariffs,[12] which are made available near the facility entrance, and these employees are capable of responding to specific account inquiries by putting the customer in contact with Company customer service representatives via telephone, this is far from being capable of accepting and processing payments onsite. It would be impractical to wholly renovate and change the purpose of the Erlanger facility and transplant existing customer service

[11] Order, 44.
[12] Spiller Examination, HVR at 1:10:46 (May 9, 2023).

representatives and a supervisor from the Company's Cincinnati Headquarters to Erlanger. Installing payment processing equipment, hiring onsite security, establishing a secure cash handling system, and renovating the facility to provide safety for both employees and customers would be a significant and unreasonable cost and would require the Company to displace existing personnel supporting the electric and/or natural gas delivery functions to accommodate such a change. This is not the best use of Company resources and costs to customers. Further, none of these costs were included in the test period of this case, as this service was neither provided in the past nor forecasted to be incurred during the test year.

Because the Erlanger facility is not capable of accommodating a full-service walk-in customer service office, the Company would have to lease a new facility to properly protect employees and the public. The facility would come with significant start-up costs as well as ongoing operational costs that are not reflected in the test year of this case. The Company estimates the leasing, capital improvements, safety upgrades, staffing, training, and security would result in initial start-up costs of at least $4.3 million in the first year, with an estimated $6.7 million in costs over a five-year timeframe. This would result in a significant expense to the Company that was neither proposed, budgeted, nor forecasted as part of this case.

Not only would it be impractical to create a Company-maintained Kentucky office to accept fee-free payments, but there is also no need to do so. Presently, customers have access to a variety of bill payment options, including the option to pay a bill "by mail, online, automatic bank draft, or at one of the over 50 locations that make up Duke Kentucky's pay agent network."[13] Many of these options require no additional fees. In fact, as the Commission acknowledges, the Company currently offers at least "one fee free in person payment location in Northern Kentucky for

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[13] Order, 43.

customers to remit payment,"[14] and the Company has not received "any negative feedback"[15] related to its bill payment offerings. Indeed, customers are using these other payment alternatives. The pay agent network processes only 1.5 percent of total customer payments on average each month. With the addition of multiple Kentucky Kroger locations, this already adequate service would be further improved. The Company therefore urges the Commission to reconsider this portion of its Order to permit the Company to offer additional fee-free payment locations at Kentucky Kroger locations as described above.

While the Company appreciates that the Commission has identified an additional fee-free payment avenue that could potentially be provided to customers, immediately constructing or converting a new facility to accept in-person fee-free payments from customers is not an appropriate or cost-effective approach at this time. Instead, the Company respectfully poses a workable alternative. The Company requests that the Commission reconsider its requirement that the Company establish a local Kentucky Company office for fee-free payment location and instead find that the establishment of additional fee-free payment locations at Kroger stores satisfies the Commission's concern.

In the alternative, the Company requests that the Commission convert the requirement in its Order that the Company staff a Kentucky location that can accept fee-free walk-in bill payments from customers to a requirement that the Company study the potential impacts to customers of such a proposal. Notably, the Company presented a similar study to the Commission on or about April 28, 2009 after the Company determined that closing its walk-in payment centers was prudent given declining usage of this payment alternative by customers in the preceding years, and the availability and customers' usage of alternative payment options. The Company submits that a

[14] *Id.*
[15] *Id.*

similar analysis would be beneficial for the Company, its customers, and the Commission in this instance before undertaking the significant expense to comply with the Commission's current directive and implement a walk-in center that is unlikely to be used by customers. The Company would commit to performing such a study twenty-four months following implementation of the proposal to add additional fee-free payment options through Kroger and would provide the results to the Commission as the Commission finds necessary. This alternative proposal will help ensure that the establishment and staffing and of an onsite fee-free payment location is truly a necessary, prudent, and reasonable investment. The Company looks forward to working with the Commission further on viable and achievable solutions for customer payment methods.

C. Waiver of 807 KAR 5:006, Section 7(1)(a)(3) (Section 7) for Time of Use with Critical Peak Pricing (Rate RS-TOU-CPP)

While the Commission approved the Company's proposal to implement its new time-based, dynamic Rate RS-TOU-CPP,[16] the Commission's denial of the Company's request for a Section 7 waiver for customers taking service under Rate RS-TOU-CPP is at odds with the technical design of the rate that allows the Company to offer Rate RS-TOU-CPP to customers in a cost-effective manner.[17] The Company is not able to implement the rate as it is currently approved (*i.e.*, with the accompanying waiver denied) without significant billing system reprogramming that will take months and involve significant expense. It is not as simple as inserting the meter readings through the Company's billing system. Rather, significant redesign and reprogramming must occur. As such, the Company is in the unfortunate situation where it must either not implement the rate as ordered (*i.e.*, absent the meter readings) or not implement the rate at all.

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[16] *Id.* at 49.
[17] *Id.* at 89. Note that per Attachment A to this Petition for Rehearing, the Company requests a clarification that the Commission in fact denied the Company's request for a waiver under 807 KAR 5:006, Section 7(1)(a)(3).

The Commission did not provide any reasoning for denying this waiver, as the body of the Commission's Order simply notes that the Company requested a waiver,[18] and then in Order Point 27 states that the waiver is denied.[19] A waiver of Section 7 as applied to Rate RS-TOU-CPP would allow the Company to omit the present and last preceding meter readings from the bills of customers taking service under Rate RS-TOU-CPP. Such a waiver is necessary for the Company to implement Rate RS-TOU-CPP effectively.

As described by Company witness Bruce Sailers, the technical requirements of the Company's billing system, along with the inapplicability of scalar meter reading information to interval-billed time-of-use rate customers, counsels in favor of a Section 7 waiver:

> The Company will need a waiver of rule 807 KAR 5:006 Section 7(a)(3) regarding the manner in which usage is displayed on a customer's bill under the proposed RS-TOU-CPP as it relates to providing the beginning and ending meter reading for this new interval-billed rate. . . . The inclusion of meter readings was more meaningful under traditional rate structures; however, with interval usage data comes more dynamic pricing structures; *the beginning and ending meter readings are no longer relevant to the customer bills* under interval-billed structures. The customer bills will continue to provide information regarding usage that occurred during relevant bill periods. Furthermore, as a result of the Company's deployment of its new Advanced Metering Infrastructure (AMI), customers have even greater access to actual usage information in near real-time via the Company's website. Therefore, even though the Company is proposing not to include this information on the bill going forward, customers who desire that information will have the mean[s] [*sic*] to access it themselves upon demand. *The Commission previously granted similar treatment for interval-billed rates as part of the Company's last electric rate case proceeding*.[20]

Absent reasoning from the Commission in its Order, the Company cannot discern why such a waiver was not approved in this case.

[18] *Id.* at 49.
[19] *Id.* at 89.
[20] Bruce L. Sailers Direct Testimony (Sailers Direct), 18 (Dec. 1, 2023) (emphasis added).

Further, as noted by Company witness Mr. Sailers above, the Commission previously approved a similar Section 7 waiver request in the Company's last electric base rate case (the 2019 Rate Case):

> Duke [Energy] Kentucky requests a deviation from 807 KAR 5:006, Section 7(1)(a)3 to allow it to not include beginning and ending meter readings for certain interval-billed rates. Duke [Energy] Kentucky argues that beginning and ending meter readings are not relevant to customer bills under dynamic pricing structures. Duke [Energy] Kentucky states that customers served under such schedules have access to actual usage information in near real-time via Duke [Energy] Kentucky's website. The deviation would apply to the following rate schedules: Rate DP, Service at Primary Distribution Voltage, Rate DS, Service at Distribution Voltage, Rate DT, Time-of-Day Rate for Service at Distribution Voltage, Rate TT, Time-of-Day Service at Transmission Voltage, and Rate EH, Optional Rate for Electric Space Heating, as well as any future proposed rates that utilize AMI usage data for billing purposes.
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> The Commission finds the request for deviation from 807 KAR 5:006, Section 7(1)(a)3 to be reasonable, in part, and that it should be approved for the specific rate schedules listed in Duke [Energy] Kentucky's application; however, the Commission will not approve the deviation request for any future proposed rates that utilize AMI usage data for billing purposes. Duke [Energy] Kentucky will need to request a separate deviation from 807 KAR 5:006, Section 7(1)(a)3 for any future proposed rates that utilize AMI usage for billing purposes.[21]

Thus, the Company's proposal for a Section 7 waiver for a similar dynamic pricing structure was deemed "reasonable" by the Commission just a handful of years ago, and per the Commission's mandate in the 2019 Rate Case, cited above, the Company requested a separate Section 7 deviation for its proposal in this case. The Company therefore renews its request for a Section 7 waiver as part of this Petition for Rehearing, and requests that the Commission reconsider granting this waiver.

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[21] *In the Matter of 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 at 60–61 (Apr. 27, 2020) (internal citations omitted).

However, in the event that the Commission does not reverse its decision and grant the requested Section 7 waiver, the Company requests that the Commission simply deny the Company's request to implement this rate in total. In such case, the Company will examine other residential time-of-use rates that can be implemented in a cost-effective manner and bring them to the Commission for consideration in the future, keeping in mind the Commission's desire to have meter readings present on customer bills.

D. Planned Outage Operations and Maintenance (O&M) and Forced Outage Purchased Power Deferral Discontinuance

Duke Energy Kentucky's previously authorized deferral for forced and planned outage expenses above and below base rates is reasonable and appropriately benefits customers by smoothing out year-to-year volatility in outage expenses, avoiding rate shock that would occur if the Company timed its rate case increases with incurrence of significant outages, and allowing the Company some measure of mitigating volatility in its income statement year-to-year due to significant outage expenses. The financial health of the Company is vital to ensuring reasonable customer rates and the Company therefore requests that the Commission reconsider its denial of these deferrals going forward.[22]

In Case No. 2017-00321, the Commission previously authorized the Company to begin deferring annual expenses for (1) planned outage O&M and (2) replacement power expense not recovered in the Fuel Adjustment Clause (FAC), each above or below the amount being recovered in base rates.[23] This deferral is based on the annual amounts of expenses incurred compared to the annual amount included in base rates.[24] The Company supported this request in Case No. 2017-

[22] Order, 18, 88.
[23] Lisa D. Steinkuhl Direct Testimony, 17 (Dec. 1, 2022).
[24] *Id.*

00321 through its witnesses, including David Doss, who explained the need for this mechanism as follows:

> The Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the costs.
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> The costs for which the Company is seeking to create the regulatory deferrals represent incremental costs or savings compared to normalized or expected levels, and as such they effectively constitute extraordinary non-recurring expenses (or savings) which could not have reasonably been anticipated or included in the utility's planning. The actual costs of these items are unable to be planned or anticipated.
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> The Company's forecasted test year budget for outage maintenance expense and replacement power costs for the Company's East Bend coal-fired Generating Station (East Bend), and Woodsdale Combustion Turbines (Woodsdale) have been adjusted to reflect a representative (*i.e.,* average) level of expense. Outage maintenance expense has been normalized based upon four years of actual maintenance expense and two years of projected maintenance expenses. Replacement power costs reflect the forecasted amounts from the GenTrader production cost model for the test period. Permitting the Company to defer for future recovery any incremental amount over or under what is established in base rates for these two expenses will ensure that customers are not over paying and the Company is not under recovering for actual costs incurred in serving customers.
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> Creating these two deferral mechanisms will insulate customers from rate shock that could happen if the Company were to file a base rate case with a test year reflecting actual costs of a significant planned maintenance outage or a year where replacement power expenses were substantial. The deferral mechanisms balance the need for protecting customers from over paying for these costs when the utility's actual costs incurred are below the levels used to establish base rates, and conversely mitigate the utility's risk to financial stability and performance during years where the Company's actual costs incurred are higher than those used to establish base rates.
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> Because Duke Energy Kentucky is relatively small, the swings from year to year in the costs of planned outages and replacement power for forced outages causes volatility in the Company's earnings. The proposed deferral mechanisms are designed so that, over time, the balance should approach $0, but will prevent these

> two volatile cost items from having a significant influence on the Company's earnings.[25]

The reasoning to continue this deferral holds true today. Indeed, its importance is even greater today, as the Company is continually facing increased cost pressure to maintain its fossil-fired generating assets as they age and approach the end of their designed or economic useful life. Maintaining this deferral will continue to insulate customers from rate volatility due to planned outages, which could otherwise drive the need for base rate increases. Duke Energy Kentucky continues to be a small utility and the swings from year to year in the costs of planned outages and replacement power causes volatility.

In its Order, the Commission found that these deferrals are "no longer necessary, given that Duke [Energy] Kentucky expects the expenses to be in line with the base rate amounts."[26] While the Commission is correct that over time and on average, these outage expenses should align to the amounts included in base rates, nonetheless, these expenses are volatile year to year. Thus, while there are years in which these expenses are greater than base rate amounts, there are also years in which these expenses are less. An aging coal-fired generation plant like the Company's East Bend Generating Station (East Bend)—which will increasingly require additional O&M and purchased power replacement as it ages into retirement—compounds this issue.[27] The deferral mitigates the impact of this year-to-year volatility for both the Company and its customers, as it allows the Company to effectively average out these expenses over a period of time in its income

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[25] *In the Matter of the 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. 2017-000321, Direct Testimony of David Doss at 4–6 (Sept. 1, 2017).
[26] Order, 18.
[27] *See, e.g.*, William Luke Rebuttal Testimony, 3 (Apr. 5, 2023) ("East Bend would be a 60-year-old asset in 2041, requiring increasing major maintenance and operating costs to remain operational and dispatchable as a result of aging equipment and infrastructure.").

statement, resulting in more predictable, stable expenses on the Company's financial statements. The strong financial health of the Company is vital to keeping rates reasonable for customers.

Moreover, the Commission's denial of this ongoing deferral is at odds with the Commission's stated desire for the Company to operate the unit as long as it is economically viable to do so. To accomplish this goal, the Company must continue to invest in the units and continue conducting needed and timely maintenance. The deferral mechanism thus directly benefits customers, as it allows the Company to manage these expenses on its balance sheet by keeping an average amount in base rates, without having to time its rate increases to recover those more significant costs when they are incurred, which could create even greater volatility to customers through more frequent rate increase requests.

It is worth considering the incentives on both sides of this equation. Removal of this deferral has the potential to drive future rate cases. Barring a deferral, the Company will need to time more of its investments to high-cost outage years, which will drive the need for the Company to recover those large costs quickly. This, in turn, could drive the Company to have to file rate cases more often, resulting in more frequent rate increases for customers. On the other hand, if costs decline below what is in base rates in a given year, the absence of a deferral means that the cost level in rates would not be smoothed out to pass lower costs on to customers.

The Company makes every effort to contain costs recovered from its customers, and this deferral is a mechanism that allows the Company to recover its outage costs while smoothing out the rate impacts experienced by customers. It allows the Commission to ensure that the customers are paying no more and no less than the actual costs incurred by the Company over time while also allowing the Company to maintain strong financial health, which affects financing costs that ultimately impact customer rates.

The Company's aging generation fleet is likely to become more expensive overall as it experiences more planned outages (as maintenance becomes increasingly necessary to maintain the units) and forced outages (as more equipment fails and requires replacement until retirement), and the deferral would allow the Company to mitigate the impact that customers experience from these outages year to year by offsetting higher cost outage years with lower cost years. Duke Energy Kentucky therefore requests that the Commission grant rehearing on this point and allow the Company to continue the deferral mechanism for both planned outage O&M expense and forced outage purchased power expense.

E. East Bend Retirement Date

Duke Energy Kentucky maintains that the record supports a probable retirement date for East Bend of 2035, not 2041, and the depreciation rates and expense for this asset should be aligned with this date. The Commission's finding otherwise is not in line with the record, clear indications of future environmental regulation that will require earlier retirement, and the operational ramifications the Company explained in the record regarding the projected retirement dates of East Bend and Woodsdale occurring within one year of each other. While the Company's Initial Post-Hearing Brief (Initial Brief) addresses the volume of record evidence suggesting that the most likely retirement date for East Bend is 2035,[28] additional points related to East Bend's future economic retirement are worth addressing in light of the Commission's Order.

The Commission found that the depreciation rate for East Bend should reflect a retirement date of 2041 so as to "balance[] the risk of retirement before the unit is fully depreciated while encouraging Duke [Energy] Kentucky to operate East Bend as long as it is economically viable."[29] While the Company is concerned that this statement fails to capture the nuances of this highly

[28] *See* Brief, 34–45.
[29] Order, 14.

contested issue, this also does not justify ignoring the onset of carbon regulation that will make operation of East Bend beyond 2035 unlikely, at least not at existing capacity factors. The Company's 2021 Integrated Resource Plan (IRP) provided a complete range of analyses that support an earlier retirement date for East Bend than its current depreciation rate reflects. As noted in prior briefing, while the Company could not have predicted the specific environmental regulations that would be implemented in the future, its 2021 IRP in fact accounted for a range of environmental regulation scenarios that would impact the long-term economic viability of East Bend as a generating unit.[30] It is unclear how the Company's 2021 IRP "is not a reasonable planning document"[31] for East Bend's retirement date, as the 2021 IRP addresses that exact subject in great detail—the future economic viability and projected retirements of fossil fuel-fired generating resources. The Company's 2021 IRP is nothing if not complete and reasonable, as are its carbon regulation analyses.

In fact, the Company's 2021 IRP accounted for regulations like the Clean Air Act's Section 111(d) rules (111(d) Rules), even though the 111(d) Rules were first proposed by the United States Environmental Protection Agency (EPA) during the hearing in this proceeding.[32] Because the proposed 111(d) Rules were only first introduced during the hearing, it was inappropriate to address them in specific detail as part of the hearing, and certainly as part of the Company's 2021 IRP. However, with the opportunity for all parties and the Commission to now digest the 111(d) Rules, several months after they were first proposed, it has become clear that these regulations

[30] *See* Scott Park Rebuttal Testimony, 12 (Apr. 14, 2023); Duke Energy Kentucky Post-Hearing Reply Brief, 3 (June 19, 2023).
[31] Order at 14.
[32] *See* SC Exhibit 7 (Fact Sheet, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, Proposed Rule); SC Exhibit 8 (New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule).

alone, if implemented, will require the Company to retire East Bend much earlier than 2041. With a carbon regulation scenario quickly materializing in the near future, "economic retirement of East Bend follows within a few years."[33]

Additionally, it should be noted that the Commission's Order accepted the Company's revised projection for the useful and economic life of its Woodsdale units, extending their depreciable life to 2040.[34] If the Company's projections were reasonable for its natural gas units, they should be reasonable for its coal-fired assets. Moreover, the Commission's Order fails to consider or discuss the risk of timing the depreciation and potential retirement of both of these assets within twelve months of one another. Such a drastic change to the Company's portfolio creates a proverbial reliability and rate shock cliff for customers where the Company's entire fleet is effectively retiring all at once and customers would be facing increased costs for replacing all of these assets together. The Company's proposed depreciable life for East Bend to retire in 2035 provides a much smoother transition for its fleet that is beneficial to customers, mitigates rate shock, and allows the Company to plan for the resource adequacy of its system over time rather than all at once.

Thus, amending the depreciable life of East Bend is reasonable and necessary, and the Commission's suggestion otherwise "in light of the rate increase to customers resulting from such a decision" ignores a number of important concepts, not the least of which is the increasing likelihood that environmental regulations will require an earlier retirement of the unit and delaying action will only increase the retirement cost to customers. Further, the utility is entitled to recover its costs of providing safe, reliable, reasonable, and adequate service to customers, which certainly includes costs related to a utility's generating units. Aligning the depreciable life of the unit with

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[33] SC Exhibit 1 (Duke Energy Kentucky 2021 IRP), 42–43.
[34] Order, 13.

its anticipated service life of 2035 actually benefits customers over the long term, as it reduces the costs for future customers when replacement generation goes into service and appropriately aligns those costs with the customers who are benefiting from the asset. This inequity will only now be exacerbated with the Commission's findings regarding terminal net salvage, as discussed below. The Commission's Order fails to acknowledge these important policies, and the Company requests rehearing on East Bend's projected retirement date in light of upcoming carbon regulation that makes earlier retirement likely.

F. Terminal Net Salvage Adjustment

Using KRS 278.264(2), as recently modified by Kentucky Senate Bill 4 (SB 4), the Commission ordered removal of terminal net salvage (*i.e.*, decommissioning costs) from the Company's depreciation rates for its generating assets.[35] The Commission's Order on this point is misaligned with the statute, the laws governing utilities' right to recovery of reasonable costs, and public policy, and Duke Energy Kentucky seeks rehearing on this issue for the following reasons.

First, the Commission's brief ruling on this point potentially creates millions of dollars in stranded costs, which inappropriately deprives the Company of a reasonable opportunity to recover costs that it has properly incurred in providing safe, reliable electric service to local Kentuckians. Removing these costs from depreciation rates means that at the time of retirement, customers will bear the entire burden of decommissioning the units all at once, rather than over the useful life of the asset, as has been the case for decades of utility ratemaking. East Bend is the last steam production asset remaining on the Company's books and once retired, any remaining undepreciated plant on the books are considered stranded costs, as there are no more assets in the group of accounts to allocate these costs. Assuming both the Commission's removal of

[35] *Id.* at 14–15, 87.

approximately $6 million of annual net salvage from depreciation expense and the Company's 2035 estimated retirement timeline for East Bend, the Commission's Order pushes approximately $72 million in costs to future ratepayers.

The Commission has previously approved decommissioning costs in the Company's depreciation rates,[36] properly finding that decommissioning costs are an inherent component of a generating asset's depreciation. Upon the inevitable retirement of virtually any generating asset (whether or not fossil-fueled like East Bend), the Company will have no choice but to incur costs to safely decommission that plant in compliance with Kentucky law. Removing decommissioning costs from rates during the life of the facilities not only potentially increases the total costs of retirement, but also creates generational inequity, as the customers who received the benefit of the plant's operations will not contribute to its ultimate retirement. This approach also disadvantages the Company, as it effectively restructures the value of the Company's generating assets that will continue to serve customers through their useful lives. In turn, refusing the Company the right to recover these costs in its depreciation rates creates anticompetitive precedent, and the Company strongly urges the Commission to reconsider the ramifications of its ruling.

Further, the Commission's use of SB 4 to remove decommissioning costs from all generating asset depreciation rates conflicts with SB 4 on its face, as SB 4 applies to "fossil fuel-fired combustion or steam generating sources" only.[37] Despite this, the Commission removed decommissioning costs from the depreciation rates of all of the Company's generating units—

[36] John J. Spanos Rebuttal Testimony, 5 (Apr. 14, 2023); *In the Matter of the 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 at 27 (Apr. 13, 2018).
[37] KRS 278.262(a).

including its solar energy generation facilities.[38] These renewable energy facilities are, by definition, *not* "fossil fuel-fired combustion or steam generating sources."[39] Thus, even if the Commission's interpretation of KRS 278.264(2) were correct, it does not apply to the Company's renewable generating facilities, and the Commission should, at a minimum, reverse its ruling with respect to the Company's solar generation assets, which would increase the Commission approved revenue requirement by $0.141 million.

Additionally, the Commission's ruling results in inconsistent depreciation accounting between its generating assets and its distribution and transmission assets. The depreciation rates of those distribution and transmission assets still include, and properly so, an amount for terminal net salvage. Sound ratemaking principles would not support this inconsistency in depreciation rate computations for distribution and transmission assets versus generating assets.

Finally, since the Commission has previously approved decommissioning costs in the Company's depreciation rates and the Company accrued it through Accumulated Depreciation, there will be a certain balance in Accumulated Depreciation that won't be representative of the total estimated decommissioning costs at the end of the life of the assets. When the actual decommissioning begins, the Company must continue recording the actual decommissioning costs to Accumulated Depreciation as required by the Federal Energy Regulatory Commission. Because the Accumulated Depreciation balance won't be sufficient to cover total actual decommissioning costs, the accumulated depreciation balance will ultimately become a debit balance that needs to be recovered from customers at that time. This demonstrates further why a stranded asset will exist as a result of this ruling. The Commission's Order provides no guidance on this point, and

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[38] Order, 14 (stating that "the Commission cannot allow recovery of costs for the retirement of the electric generating units" without recognizing that this does not apply to the Company's renewable generating units).
[39] KRS 278.262(a).

generally fails to address or provide solutions to the Company on how they plan for a known stranded asset. Thus, the Commission's Order on this point has far-reaching implications for the Company's future accounting practices and all Kentucky. Disallowing decommissioning costs for all generating assets regardless of their generating resource is at odds with both the explicit mandates of SB 4 and competitive ratemaking policy at large.

G. Rate Case Expense Disallowances

As the Commission notes, the Company included estimated total rate case expense of $1.136 million in its Application, which was very close to the final expense update of $1.002 million (which included actual and pending expenses (final costs)) the Company submitted at the time its Initial brief was filed.[40] At the time that briefing closed, the Company had to make a determination as to what costs would be requested for recovery, including costs that were being incurred but had not yet been invoiced or processed. As a result, the Company had to estimate the pending costs. In its Order, the Commission denied recovery of certain final costs that were estimated.[41] The Company maintains that the use of estimated rate case expense in certain limited circumstances—particularly for legal fees incurred during the hearing and shortly thereafter for legal briefing—was necessary. Indeed, it was the only means possible in determining rate case expenses for these costs given the timing of the work being performed and the timing of when the costs had to be submitted to the Commission for consideration in the Company's Initial Brief. As such, the Company requests rehearing on this issue as it pertains to the Company's estimated rate case expenses.

[40] Order, 18–19.
[41] The Company is not seeking rehearing on rate case disallowances deemed unreasonable by the Commission related to additional publication requirements and certain consultant fees.

By the very nature of a rate case procedural schedule, the Company has no choice but to use estimates for certain rate case expenses. In this case, the record closed at the time post-hearing briefing was filed, only a few weeks after the hearing. At that time, the Company did not have all of its actual final expenses for outside legal and consultant expenses, as the work on the case was not yet complete.[42] To ensure accurate estimates, the Company requested from outside legal and consultants their remaining expenses which had been incurred but not invoiced, as well as reasonably expected expenses to complete post hearing activities. The majority of these estimates that were denied by the Commission ($160,000) were for the costs of outside counsel to assist with the production of post-hearing data requests, preparation and filing of post-hearing briefs, and review of intervenor briefs. In addition to these considerations, the actual amounts invoiced to the Company after this final expense update was made and submitted in its Initial Brief were within a reasonable margin of the estimated expenses.

The Company acknowledges that a true-up of estimated expenses to actuals can be appropriate for rate case expense and is open to that possibility in future cases, but it is not equitable to limit recovery in this case to actual expenses when the record closes while expenses are still being incurred but not yet known. Thus, although the Company disagrees with the entire disallowance ordered by the Commission, the Company seeks rehearing on the limited matter of allowing the $160,000 of estimated outside counsel fees, which results in a revenue requirement increase of $32,000, as well as clarification from the Commission as to the appropriate use of estimated expenses as part of future cases proceeding before the Commission.

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[42] The Company initially provided estimates as part of the Application in Schedules D-2.17 and F-6. Staff then requested "[a]n itemized estimate of the total cost to be incurred for this case," and in response to this request, the Company provided the estimates in question on June 2, 2023 as part of its Fifth Supplemental Response to STAFF-DR-01-014, Attachment 1.

H. Items for Correction or Clarification

1. Requested Clerical Corrections to Order

The Company has also identified several errors in the Commission's Order that largely appear to be clerical but would benefit from correction in order to establish a clear and accurate final order. A summary of these items is included as Attachment A to this Petition for Rehearing. The Company asks that the Commission implement these corrections.

2. Rate RS-TOU-CPP Deferral

While the body of the Commission's Order indicates that with respect to Rate RS-TOU-CPP, the Company "requested a deferral for lost revenue for recovery in its next electric rate case,"[43] the remainder of the Order is silent as to the Commission's ruling on this deferral. Duke Energy Kentucky therefore requests that the Commission make a ruling on this point and approve the requested deferral, as it will allow the Company to offer this dynamic rate structure to customers while limiting the Company's exposure to any lost revenues that may result from customers' transition from Rate RS to the new Rate RS-TOU-CPP.[44] If however, the Commission denies the Company's request to grant a Section 7 waiver, as discussed above, and denies Rate RS-TOU-CPP on rehearing, the Company withdraws this deferral request as moot.

3. Total Capitalization

The Commission's Order states the following: "Duke [Energy] Kentucky proposes a total capitalization for the forecasted test period of $1,842.376 million, which reflects financing activities through June 2024. The Commission accepts Duke [Energy] Kentucky's proposed capitalization amount."[45] This number was the total capitalization, including investment tax credits

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[43] Order, 49.
[44] Sailers Direct, 17. The Company additionally proposed initially limiting Rate RS-TOU-CPP to 1,000 participants, which will also help the Company mitigate lost revenues while implementing this experimental rate structure.
[45] Order, 25.

(ITCs), on the as-filed Schedule J-1 to the Application. However, the Company changed its request in rebuttal testimony to a total capitalization for the forecasted test period of $1,825.184 million not including ITCs, and $1,828.423 million including ITCs.[46] Additionally, the Order states elsewhere that the accepted total capitalization amount is $1,825.184 million (the value the Company provided in rebuttal testimony, not including ITCs),[47] so confirmation on this point is appropriate.

4. Revision of Certain Rates and Charges

Notwithstanding Section II.A above, there are several rates and charges in the Order's Appendix B that are listed as the Company's as-filed charges in the Application that have not been adjusted to reflect the revenue requirement the Commission approved in its Order in this proceeding. The Company requests that the Commission review these rates, as described below in more detail, and provide appropriate revisions as necessary to the current Appendix B charges.[48] In order to aid the Commission's review, the Company outlines below how such adjustment might be completed:

a. Rate RS-TOU-CPP

Rate RS-TOU-CPP is designed to be revenue neutral to Rate RS – Residential Service on a class basis, meaning that if all residential customers who are taking service on Rate RS would instead take service on Rate RS-TOU-CPP, the revenues collected by the Company would be the same. Given that revenues for Rate RS were decreased in the Order as compared to the Company's Application, Rate RS-TOU-CPP charges should also be revised. The Company filed Attachment BLS-5 to the Direct Testimony of Mr. Sailers. This attachment presents the calculation

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[46] Christopher R. Bauer Rebuttal Testimony, 2, Attachment CRB-1, 1 (Apr. 14, 2023).
[47] Order, 33–34.
[48] If the Commission grants rehearing on this issue and the Commission so desires and deems it appropriate, the Company is willing to discuss the calculation of these revisions as part of an in-person or virtual technical conference where all parties could participate.

methodology used by the Company in Company's application to calculate Rate RS-TOU-CPP charges. As appropriate, the Commission could use the same methodology with revised inputs to calculate revised Rate RS-TOU-CPP charges.

b. Rate RTP – Experimental Real Time Pricing Program and Rider GSS – Generation Support Service

For Rate RTP and Rider GSS, a worksheet is present in Schedule M to the Application (tab "RTP WORKSHEET"). The referenced charges are calculated from cost-of-service study (COSS) values. If the Commission elects not to perform a revised COSS for rate calculations, these rates could be adjusted by a corresponding percentage decrease applied to these charges. If adjusting these charges will decrease revenues associated with Rate RTP or Rider GSS customers, that would also lead to adjustments in the base rate charges to recapture the total approved revenue requirements.

c. The distribution demand charge for Rate DT – Time-of-Day Rate for Service at Distribution Voltage

As described in the Direct Testimony of Mr. Sailers, the Rate DT distribution demand charge is targeted to collect the distribution demand component of Rate DT revenues as determined in the Company's COSS.[49] While the Order's Appendix B Rate DT charges altogether may collect the appropriate revenues from Rate DT customers in total for that rate, the distribution demand charge of $6.23 shown on Appendix B is unchanged from the Company's Application and likely collects more than the distribution demand component under the Commission's Order. This should be revised with a corresponding change in the other charges in Rate DT, ensuring that all the final charges for Rate DT produce the appropriate revenue collection.

[49] Sailers Direct, 10.

d. The lighting equipment found in the tables of Rate LED – LED Outdoor Lighting Electric Service

Attachment BLS-2 and Confidential Attachment BLS-3 to Mr. Sailers' Direct Testimony present the calculations for the Rate LED equipment. Given revised components to the Company's weighted average cost of capital, the Levelized Fixed Charge Rates (LFCR) in Attachment BLS-2 should correspondingly change. These revised LFCR values should be used for input into the equipment charge calculations in Confidential Attachment BLS-3.

III. CONCLUSION

WHEREFORE, on the basis of the foregoing, Duke Energy Kentucky respectfully requests that the Commission grant the relief requested herein.

This 1st day of November, 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 November 1, 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.[50]

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

ATTACHMENT A

The Company requests that the Commission make the corrections identified in Table 1 below to its Order to preserve the record in this case.

Table 1. Requested Corrections to Order

Order		**Corrections to Order**	
<u>Statement</u>	***<u>Citation</u>***	***<u>Requested Correction</u>*** *<u>Underlined</u> = Addition* *~~Strikethrough~~ = Deletion*	***<u>Citation</u>***
"The average monthly residential electric bill increase based on the proposed electric base rates would be approximately 20.6 percent or approximately $19 for a residential customer using 1,000 kWh of electricity."	Order at 2.	"The average monthly residential electric bill increase based on the proposed electric base rates would be approximately ~~20.6~~<u>21.4</u> percent or approximately $~~19~~<u>25</u> for a residential customer using 1,000 kWh of electricity."	Application at 5.
"The decrease in depreciation expense results in a revenue requirement decrease of $5.226 million."	Order at 13–14.	"The decrease in depreciation expense results in a revenue requirement decrease of $~~5.226~~<u>10.452</u> million."	Order at Appendix A.
"The net effect of the adjustment of the East Bend retirement date and removal of decommissioning costs on Duke Kentucky's depreciation rates is $15.848 million."	Order at 15.	"The net effect of the adjustment of the East Bend retirement date and removal of decommissioning costs on Duke Kentucky's ~~depreciation rates~~<u> revenue requirement</u> is $~~15.848~~<u>15.847</u> million."	Order at Appendix A.
"The net revenue requirement impact of these adjustments is a decrease of $2.072 million."	Order at 18.	"The net revenue requirement impact of ~~these adjustments~~<u>this adjustment</u> is a decrease of $~~2.072~~<u>0.043</u> million."	Order at Appendix A.
"Lastly, Duke Kentucky's witnesses and consultants were generally unable to explain Duke Kentucky's	Order at 20, n.89.	"Lastly, Duke Kentucky's witnesses and consultants were generally unable to explain Duke Kentucky's accounts receivable	Order at 6.

accounts receivable treatment and expenses were incurred to provide testimony on this topic. *See* Hearing Video Transcript (HVT) of the March 10, 2023 Hearing at 16:25:33–17:03:55."		treatment and expenses were incurred to provide testimony on this topic. *See* Hearing Video Transcript (HVT) of the ~~March~~May 10, 2023 Hearing at 16:25:33–17:03:55."	
"As discussed above, the Commission has determined that Duke Kentucky's net investment rate based is $1,115.444 million, as shown below: [citing "Reverse Roll-in of Costs Currently Recovered Through ESM" as (53.795 million) and Adjusted Rate Base as $1,115.444 million]."	Order at 25.	"As discussed above, the Commission has determined that Duke Kentucky's net investment rate base~~d~~ is $~~1,115.444~~1,116.509 million, as shown below: [citing "Reverse Roll-in of Costs Currently Recovered Through ESM" as ($~~53.795~~52,730 million) and Adjusted Rate Base as $~~1,115.444~~ 1,116.509 million]."	Staff-DR-03-021 Revised Supplemental Attachment.[1]
"Duke Kentucky's request for a waiver from 807 KAR 5:006 Section 7(a)(3) is denied."	Order at 89.	"Duke Kentucky's request for a waiver from 807 KAR 5:006 Section 7(1)(a)(3) is denied."	KAR 5:006 Section 7(1)(a)(3); Order at 49.
"Reduce Return on Equity from 10.35% to 9.55%"	Order at Appendix A.	"Reduce Return on Equity from 10.35% to 9.~~5~~75%"	Order at 41.

[1] The cited ($53.795 million) was originally cited in AG-DR-02-040 Attachment 3 but was subsequently corrected by the Company in Staff-DR-03-021 Supplemental Attachment. This adjustment affects the Adjusted Rate Base, as noted above.