COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)	Case No. 2023-00159

SECTION III

DIRECT TESTIMONY OF
WISEMAN, WEST, FETTER, COBERN, CLARK,
PHILLIPS, BLANKENSHIP, KERNS, VAUGHAN, MCKENZIE,
MESSNER, NIEHAUS, SPAETH, WALSH, COST,
WHITNEY, SCHLESSMAN, AND KAHN
ON BEHALF OF KENTUCKY POWER COMPANY

VOLUME 1 OF 4

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DIRECT TESTIMONY OF

CYNTHIA G. WISEMAN

ON BEHALF OF KENTUCKY POWER COMPANY

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Cynthia G. Wiseman, and I am President and Chief Operating Officer of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Arts degree in Journalism with an emphasis in Public Relations from Marshall University in Huntington, West Virginia in 1989. I have also completed the International Economic Development Council's Economic Development Institute at the University of Oklahoma. Prior to joining American Electric Power Company, Inc. ("AEP"), I spent the majority of my career in public relations and customer outreach. I worked for a large public library system in Charleston, West Virginia for 15 years. I joined Kentucky Power affiliate Appalachian Power Company ("Appalachian Power") in 2008 as a Communications Consultant where I was responsible for overseeing customer communications within Appalachian Power's three-state territory. In 2013, I was promoted to External Affairs Manager/Lobbyist where my duties included building and maintaining relationships while serving as company liaison for local, state, federal government and community officials. I joined Kentucky Power as Managing Director, External Affairs and Customer Services in April 2018 and then my title was changed to Vice President, External Affairs and Customer Service in 2019. In January 2023, I was named Interim President of Kentucky Power. I was promoted to my current position in April 2023.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH KENTUCKY POWER?

A. I am responsible for the safe, reliable, and efficient day-to-day operations of Kentucky Power and am accountable for the Company's financial performance and the quality of the services provided to our customers. Specifically, I am accountable for the Company's distribution, customer service, transmission, and generation functions to provide safe, adequate, and reliable service to Kentucky Power's customers. Additionally, my responsibilities include Kentucky Power's community involvement and economic development activities, as well as ensuring the Company's compliance with federal and state laws and regulations.

Q. ARE YOU ALSO INVOLVED IN OTHER ORGANIZATIONS WITHIN THE COMPANY'S SERVICE TERRITORY?

A. Yes. In addition to my responsibilities with the Company, I am an active member of the eastern Kentucky business and economic development community and am past-Chair of the board of directors for the Ashland Alliance, vice-chair for One East Kentucky, and board member for Leadership Kentucky and Paramount Arts Center. The Ashland Alliance is a chamber of commerce whose mission is to advance the economic development and business prosperity of Boyd and Greenup counties. One

East Kentucky is a regional non-profit organization dedicated to economic development and job creation within eastern Kentucky. Leadership Kentucky is a non-profit educational organization dedicated to identifying and preparing individuals with a broad array of leadership abilities to take an active role in advancing the Commonwealth for the common good. The Paramount Arts Center is a historic theater located in Ashland.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have filed testimony on behalf of Kentucky Power in the Company's last base rate case, Case No. 2020-00174.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is to provide a general overview of Kentucky Power and of the Company's request for a general adjustment of its electric rates. Specifically, I will:

- Provide an overview of Kentucky Power and its operations;
- Discuss Kentucky Power's commitment to its customers and several of the ways the Company is furthering that commitment;
- Describe the current challenges the Company is facing and the need for this case;
- Summarize Kentucky Power's major proposals and requests in this proceeding, including several measures proposed to reduce and offset customer rate impacts; and
- Identify and introduce the Company's witnesses.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring the following exhibit:

- Exhibit CGW-1 – Map of Kentucky Power's Service Territory

IV. OVERVIEW OF KENTUCKY POWER'S OPERATIONS

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY AND ITS OPERATIONS.

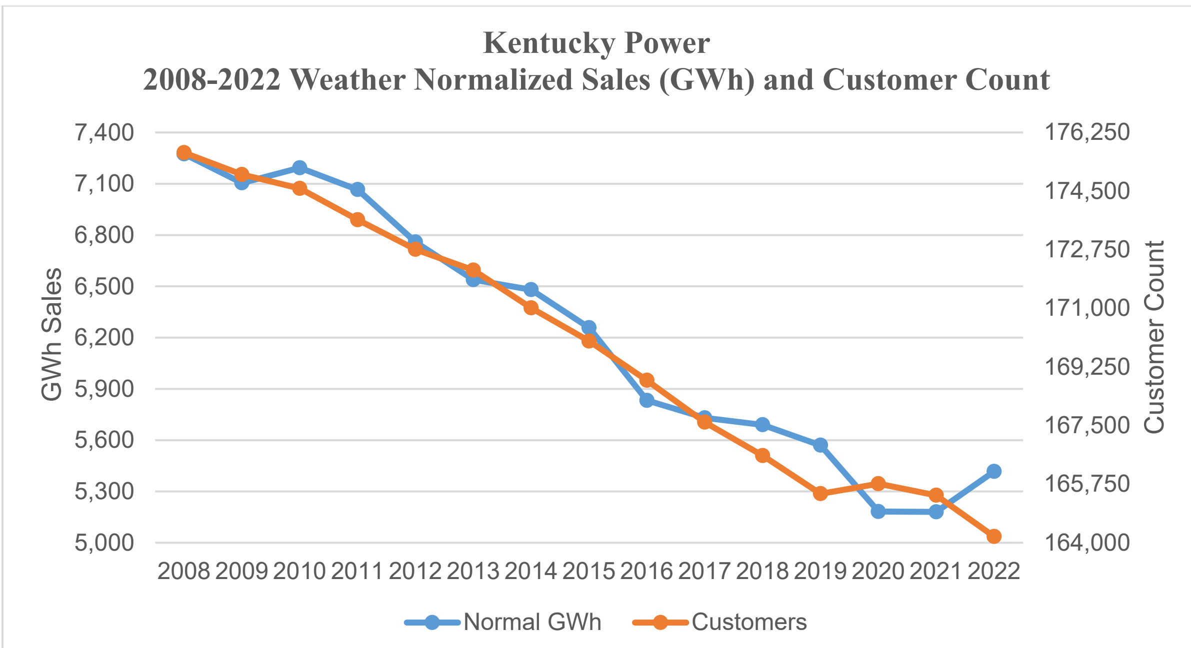
A. Kentucky Power is a wholly-owned subsidiary of AEP and is engaged in the generation, purchase, transmission, and distribution of electric power to retail customers in 20 eastern Kentucky counties. Kentucky Power also sells electric power at wholesale rates to the City of Olive Hill and the City of Vanceburg. The Company is headquartered in Ashland, Kentucky and maintains distribution operations centers in Hazard, Pikeville, and Ashland. The Company's distribution operations centers serve as a base of operations for staff in each of the Company's three districts. Exhibit CGW-1 is a map detailing the Company's service territory. Kentucky Power's service territory includes some of the most geographically challenging and economically challenged territory in the Commonwealth. Company Witnesses Phillips and Clark, respectively, detail these challenges.

Q. HAVE EASTERN KENTUCKY'S ECONOMIC CHALLENGES IMPACTED KENTUCKY POWER'S CUSTOMER COUNT AND LOAD?

A. Yes, significantly. Between March 2020 and March 2023 alone, the Company's total customer count declined by over 2,700 customers (roughly 1%), to 163,400 retail customers, and its weather normalized sales fell 127.7 gigawatt-hours (GWh) (2.3%).

Since 2019, a significant portion of the decline in sales was due to the closure of three large business customers, AK Steel, AirGas, and Our Lady of Bellefonte Hospital. The loss of those customers also represents a loss of jobs in the area, which may have precipitated other customers relocating outside of the Company's service territory to find job opportunities. These declines unfortunately follow a now long-term trend in the area and include a dramatic loss of coal mining jobs that began in the early 2000s.[1]

Figure CGW-1



As Figure CGW-1 reflects, over the period between 2008 and 2022, the Company's customer count fell by 11,482 customers, or 6.5%, and its weather-normalized retail sales fell by approximately 1,857 GWh, or 25.5%.

[1] See, for example, Appalachian Regional Commission, "Coal Production and Employment in Appalachia" (Sept. 2022), *available at* https://www.arc.gov/ wp-content/uploads/2022/09/2022-09-Coal-Production-and-Employment-in-Appalachia.pdf.

Q. PLEASE DESCRIBE KENTUCKY POWER'S WORKFORCE.

A. Kentucky Power directly employs approximately 282 people. The Company pays competitive wages and benefits, enabling it to attract and retain the skilled workers required to provide safe, adequate, and efficient service to our customers. To support the eastern Kentucky economy and offset, to some extent, the loss of jobs caused by other business closures, the Company continuously looks for opportunities to add staff in our service territory when the cost is justified by the service and customer benefits provided.

Kentucky Power's employment impact also extends beyond its direct employees. Overall, the Company also utilizes hundreds of full-time equivalent contractors daily, who perform vegetation management and construction work in eastern Kentucky. The use of independent contractors allows Kentucky Power to cost-effectively complete work when needed to provide safe and reliable service to its customers.

V. KENTUCKY POWER'S COMMITMENT TO CUSTOMERS

Q. PLEASE DESCRIBE KENTUCKY POWER'S CUSTOMER PHILOSOPHY.

A. Our commitment to our customers is the guiding principle of everything that we do, not only in the preparation of this rate case, but in all our activities, from our reliability improvement and vegetation management programs; to storm restoration; from community and economic development activities; to customer experience and assistance initiatives and programs.

Q. DO KENTUCKY POWER AND ITS EMPLOYEES ALSO SUPPORT THE COMMUNITIES AND INSTITUTIONS IN THE COMPANY'S SERVICE TERRITORY?

A. Absolutely. The Company and its employees are active and productive members of the communities we serve. During 2022, the Company contributed to charitable, educational, and civic organizations serving Kentucky Power's service territory. Kentucky Power employees participate in numerous community causes, including those that promote economic development, civic pride, and customer safety.

The focus of Kentucky Power's and the American Electric Power Foundation's charitable contributions in Kentucky Power's service area has been in the areas of housing and hunger. We recognize that we truly can do more together, and we are actively seeking partners with like goals. Each year, Kentucky Power partners with Facing Hunger and God's Pantry Food banks to raise money and collect food through an event called Power Up the Pantry. Likewise, Kentucky Power has partnered with organizations like Christian Appalachian Project and the Housing Development Alliance to improve housing in eastern Kentucky. Of the American Electric Power Foundation grants, one of the more notable recent ones was a $100,000 contribution in 2021 to the Housing Development Alliance for a redevelopment project in Hazard to build a new all-electric neighborhood that provided 15 new homes where a dilapidated strip mall stood previously. Company Witness Cobern offers additional details about that project. In the last few years, the AEP Foundation has also contributed nearly $200,000 to the Christian Appalachian Project, allowing weatherization and repair of homes.

Another example of a Foundation contribution occurred after the devastating flooding in eastern Kentucky. Recognizing that need caused by the flooding, the American Electric Power Foundation contributed $100,000, split equally among Save the Children, Foundation for Appalachian Kentucky, the American Red Cross, and the Team Kentucky fund.

Kentucky Power, AEP, and the AEP Foundation will continue to support programs that help communities ensure that residents have safe places to call home and access to nutritious food.

Q. WHAT IS THE AMERICAN ELECTRIC POWER FOUNDATION?

A. The American Electric Power Foundation supports the communities served by AEP operating companies like Kentucky Power and provides a permanent, ongoing resource for charitable initiatives involving higher dollar values and multi-year commitments in the communities Kentucky Power serves.

Kentucky Power's, AEP's, and the Foundation's charitable contributions are funded by the Company's shareholders; none are recovered through customer rates. Company Witness Cobern also discusses the Company's community outreach, customer communication, and philanthropic efforts.

Q. PLEASE BRIEFLY DESCRIBE THE IMPORTANCE OF ECONOMIC DEVELOPMENT TO THE COMPANY AND ITS CUSTOMERS.

A. Economic development and business retention are important priorities to both Kentucky Power and its customers. As noted above and discussed further in Company Witness Clark's testimony, the entire eastern Kentucky region, including the Company's service territory, is struggling economically. There is a critical need for the Company to assist with efforts to maintain existing customers and further develop the region's economy.

First and foremost, economic development is essential to ensure that the citizens in the communities Kentucky Power serves are meaningfully employed, have opportunities to create and expand businesses and industries in eastern Kentucky, and enjoy the benefits associated with an increased tax base in their communities. Moreover, the addition or expansion of business and industry results in increased load, which benefits all customers by spreading Kentucky Power's fixed costs of providing electric service and lowering customer rates.

Kentucky Power has had some recent successes working with specific commercial and industrial customers, such as Big Sandy Community and Technical College, to develop economic incentives to assist those customers and retain significant businesses and sources of employment in eastern Kentucky. In addition to these successes, as Company Witness Clark details, Kentucky Power has supported successful economic development projects through its Kentucky Power Economic Growth Grants ("K-PEGG") Program and other initiatives that have resulted in the location of new customers and creation of jobs in the Company's service territory. It is important to build upon this momentum and continue to support economic development efforts for the benefit of Kentucky Power's customers and the region as a whole. To that end, as Company Witness Clark explains, the Company seeks approval in this case to continue its K-PEGG Program through Tariff K.E.D.S. at current funding levels.

VI. CURRENT CHALLENGES FACING THE COMPANY, AND THE NEED FOR THIS CASE

Q. PLEASE DESCRIBE THE CHALLENGES THAT KENTUCKY POWER FACES IN MEETING ITS CUSTOMERS' NEEDS.

A. A major challenge that Kentucky Power faces is how to meet the needs of, and provide solutions for, customers while continuing to provide affordable and reliable electric service at a time when the costs of providing reliable electric service are rising and the number of customers over which the Company's fixed costs of service are spread are decreasing. Securitization provides the Company with a meaningful mechanism to address these challenges.

Moreover, customer needs and expectations are also changing and increasing. Today's modern digital age means residential customers are using more electronic devices and appliances than ever before, and industrial customers are relying more heavily on electronic controls and computers to manage their production facilities and processes. The many electronic devices and equipment used by our customers today are less tolerant of even minor service interruptions. This requires increasing diligence with respect to service reliability.

As discussed in more detail by Company Witness Phillips, the Company faces continued reliability challenges in the form of service interruptions due to vegetation outside the rights-of-way. These interruptions have increased over the last several years because of heavy rainfalls, plant disease, and insect infestation, including by the destructive emerald ash borer. Company Witnesses Phillips and Blankenship also detail that the Company has experienced an increase in the number and severity of storms, which have resulted in an increase to Customer Minutes of Interruption. Although the Company has reasonably invested in maintaining and improving its facilities to ensure reliable service and high-quality power, these changing needs and expectations require continual additional investment to serve our customers.

We know our customers want affordable service and our communities look to Kentucky Power to offer reasonable rates to attract and retain businesses. Kentucky Power is committed to effectively managing its business to meet customers' needs. Further, to meet customer needs and expectations, Kentucky Power requires support from its customers and regulators to help ensure its ability to provide reasonably priced, reliable electric distribution services. The ability to recover costs of capital investments and significant expenses in a timely manner remains critically important to the financial health of the Company and its ability to meet these service obligations.

Q. WHAT FACTORS WERE CONSIDERED WHEN DETERMINING THE TIMING OF FILING THIS CASE?

A. The Company has refrained from filing a base rate adjustment application for three years. However, the Company could not have delayed filing this case any longer for two reasons. First, pursuant to the Commission's Order in the Company's last base rate proceeding (Case No. 2020-00174), the Company is required to file a general base rate adjustment application for rates effective January 1, 2024.[2] Second, as I described

[2] Order at 32, *In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief*, Case No. 2020-00174 (Ky. P.S.C. January 13, 2021).

above, Kentucky Power's service territory continues to undergo historic changes in terms of economic decline and customer and load loss. These significant declines result in equally significant lost revenues for the Company. It is critical to Kentucky Power's financial integrity to act now to address those changes.

Q. WHAT IS THE COMPANY'S CURRENTLY AUTHORIZED RETURN ON EQUITY?

A. Kentucky Power's Commission-authorized return on equity ("ROE") is 9.3%, as approved by the January 13, 2021 Order in Case No. 2020-00174.[3]

Q. HAS KENTUCKY POWER EARNED ITS AUTHORIZED ROE SINCE ITS LAST RATE CASE?

A. No, it has not. Nor was the Company able to earn previously authorized ROEs, as discussed by Company Witness Mattison in Case No. 2020-00174.[4] Figure CGW-2 below compares Kentucky Power's quarterly earned ROE to its authorized ROE from Q1 2018 through Q1 2023. As shown, the Company has been unable for more than five years to earn its authorized ROE, and the most recent annual trend demonstrates an alarming reality that must be addressed for the Company to continue providing adequate and reliable service to customers.

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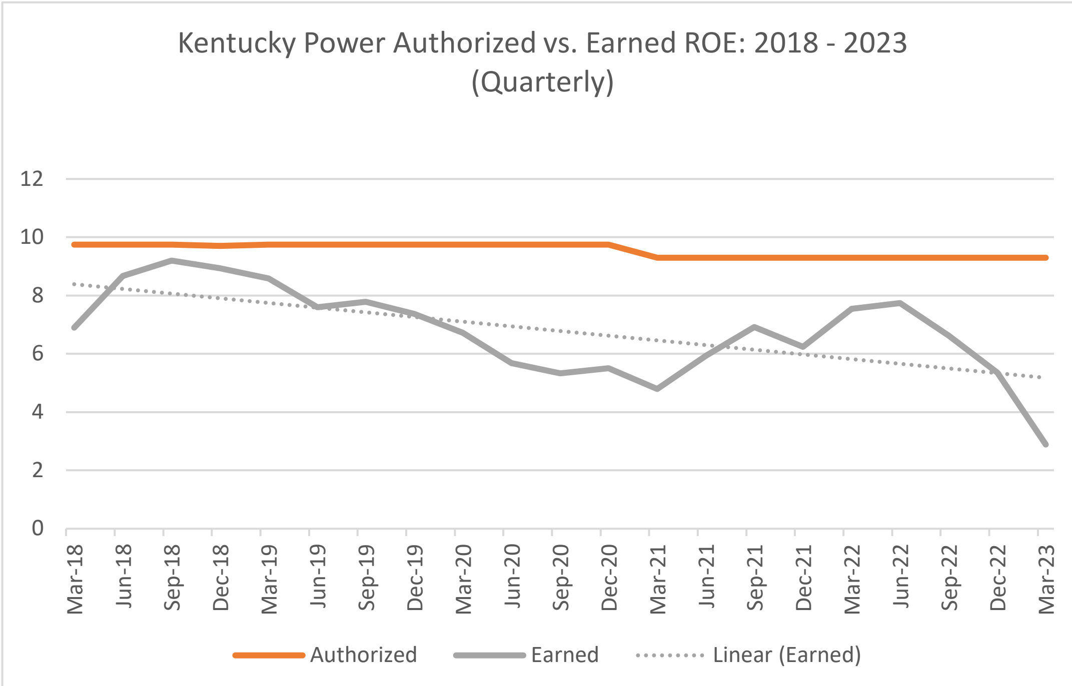
[3] *Id.*

[4] Direct Testimony of D. Brett Mattison at 14-15, *In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief*, Case No. 2020-00174 (June 29, 2020).

Figure CGW-2



Q. WHAT IS KENTUCKY POWER'S TEST YEAR-END EARNED ROE?

A. The Company's earned ROE for the 12-months ending March 31, 2023 was 2.9%. This is far below the range of ROEs found to be reasonable by the Commission in Case No. 2020-00174, or otherwise.

Q. WHAT ARE THE PRIMARY FACTORS THAT HAVE DRIVEN THE SIGNIFICANT DECLINE IN KENTUCKY POWER'S EARNED ROE BETWEEN MARCH 31, 2020 AND MARCH 31, 2023?

A. The main items driving the Company's low test-year ending earned ROE include increases in rate base since the Company's last base rate case, increases in depreciation expense from capital investment, increases in interest expense, purchased power expenses not recoverable through Tariff F.A.C., and other cost changes. Kentucky

Power's income would have needed to be $59 million higher in the test year for the Company to earn its current authorized ROE.

Q. ARE THERE OTHER FACTORS THAT HAVE AFFECTED THE COMPANY'S ROE?

A. Yes. Mild winter temperatures in early 2023 also contributed to lower-than-normal operating revenues. As the Commission is aware, Kentucky Power is a winter-peaking utility and typically realizes higher revenues during the cold winter months. More mild temperatures throughout 2023 could continue to put pressure on the Company's earnings.

In addition, the Company's current credit rating at Moody's is Baa3 (the lowest investment-grade rating). The Company also recently had its credit rating downgraded by Standard & Poor's ("S&P") from BBB+ to BBB, (the second lowest investment-grade rating). Credit ratings also can impact the Company's earned ROE. Company Witness Fetter discusses the Company's credit rating, including the recent downgrade by S&P, and the potential impacts on the Company's earned ROE in his testimony.

Q. PLEASE EXPLAIN WHY ALLOWING KENTUCKY POWER THE OPPORTUNITY TO EARN A REASONABLE RETURN AND THE COMPANY'S FINANCIAL PERFORMANCE ARE IMPORTANT.

A. Kentucky Power is an important part of the fabric of eastern Kentucky as an employer, corporate citizen, service provider, and investor. As Company Witness Fetter discusses in more detail, it is important that public utilities are provided an opportunity to earn a reasonable financial return on investment to ensure that they can attract low-cost capital to invest for customers' benefit. For example, capital is required for the Company to make the needed distribution and transmission investments described by Company Witnesses Phillips and Ali. Continued sustained poor financial performance will adversely affect the capital available to the Company and that capital's cost, as well as Kentucky Power's ability to continue to provide reliable service to customers while remaining an important part of eastern Kentucky. Company Witness McKenzie discusses the basis for his recommended ROE range and the importance of Kentucky Power being permitted the opportunity to earn it.

In addition, as a general proposition, public utilities are typically viewed as safe investment opportunities and their securities are sought by teacher retirement systems, unions, and other mainstream risk-adverse investors. These are the investors that provide the capital to support Kentucky Power's operations and look to the Commission to provide the opportunity to earn, and the Company to achieve, a fair return.

As a public utility, the Company abides by the rules and regulations of the Commonwealth and the Commission. Under the regulatory compact, Kentucky Power provides safe and reliable service in return for a fair opportunity to earn a reasonable return on its investment. Considering the decline in Kentucky Power's load and customer base, along with the other economic conditions described above, Kentucky Power's existing rates do not provide it an opportunity to earn a reasonable return.

VII. OVERVIEW OF THE COMPANY'S REQUEST TO ADJUST ITS RATES

Q. PLEASE SUMMARIZE KENTUCKY POWER'S MAJOR PROPOSALS IN THIS CASE.

A. To ensure that customers continue to receive adequate, reliable, and reasonably priced service, enhance customer care, and empower customers with service options, Kentucky Power is making several key proposals in this proceeding.

First and foremost, for the purpose of providing relief to customers, the Company is requesting a financing order pursuant to recently enacted Senate Bill 192 to securitize multiple existing regulatory assets including the Decommissioning Rider Regulatory Asset, deferred major storm costs, Rockport UPA Regulatory Asset, and certain Tariff Purchase Power Adjustment costs. The total amount sought to be securitized as of June 30, 2023 is approximately $446.7 million. Kentucky Power recognizes that the new securitization statute provides it and the Commission with a significant opportunity to reduce customers' monthly bills with respect to the costs securitized. As Company Witness Messner explains, the Company estimates that the proposed securitization is expected to provide a quantifiable net present value ("NPV") to customers of an estimated approximately $74 million. The Company has moved quickly to bring that benefit to customers by filing its application for a financing order on the first day the statute is effective.

Additionally, as detailed by Company Witnesses Phillips and West, Kentucky Power is proposing to establish a Distribution Reliability Rider, which will provide additional capital funding to expand the Company's existing trees outside the rights-of-way expansion work and additional incremental distribution investments targeted at improving reliability. As explained by Company Witness Phillips, the increased capital investment is needed to address the Company's leading cause of distribution outages, which are outages caused by trees outside the Company's rights-of-way and equipment failure. Company Witness West details that the Company plans to make the necessary investment in 2024 and will seek to begin recovery of the actual amount spent as part of a new annual filing beginning in February 2025.

To provide customers with more fuel cost certainty and stability, the Company proposes a financial hedging plan to mitigate the volatility of its PJM market energy purchases. The Company also proposes a new distributed solar garden program, which will provide significant benefits to customers, generate jobs and property taxes, and provide an approximately $66 annual energy credit to low-income customers. Company Witness Vaughan details both proposals.

To provide customers with additional time to pay their bills and better align with peer utilities in Kentucky and AEP, Kentucky Power is proposing to extend the deadline for customer bill payment from 15 to 21 days, as detailed by Company Witness Cobern. Ms. Cobern also describes Kentucky Power's proposal to increase its residential energy assistance surcharge and Company match from $0.30 per month to $0.40 per month to support approximately 1,000 additional customers through its existing energy assistance program offerings. Finally, as discussed by Company Witness Spaeth, the Company also is proposing a voluntary seasonal residential service tariff option, which will enable residential customers to reduce impacts associated with higher usage in the winter as a result of electric heating and provide greater electric heating cost predictability and stability.

Q. WHAT RATE ADJUSTMENT IS KENTUCKY POWER PROPOSING IN THIS PROCEEDING?

A. The rates proposed in the Company's application are designed to produce an increase in annual revenues of $93,935,727. This increase is based on the historical test year ending March 31, 2023, with known and measurable adjustments to test year revenues and operating expenses, which equates to a total overall increase of 13.54%. This increase represents an 18.3% increase on the average residential[5] customer's bill.

Importantly, however, and in recognition of the circumstances in the Company's service territory and which the Company's customers are facing, the Company is proposing the following measures to reduce and offset customer rate impacts:

1. **Securitization**. Over the last year, the Company took action to advocate for the passage of securitization legislation in Kentucky. SB 192, which was signed into law on March 23, 2023, allows the Company to finance certain assets through securitized bonds. At a high level, the Company's proposal to securitize certain deferred costs allows the Company to spread those costs over a longer period of time to reduce immediate bill impacts that would have been otherwise incurred without securitization, as I discussed previously. Additionally, securitizing the assets will provide the Company with immediate one-time cash flow to address some of the financial pressures it is experiencing.

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[5] Average residential customer is defined as a customer using 1,240 kWh per month.

2. **<u>Suspending Decommissioning Rider and Rockport Deferral Collection</u>**. As a further measure to mitigate January 2024 bill impacts, Kentucky Power conditionally commits to suspending collection of the Decommissioning Rider and the Rockport Deferral (collected through Tariff P.P.A.) upon implementation of base rates approved in this case. This commitment is predicated on the following occurring:

i. The Commission's approval of the Company's request to securitize the Decommissioning Rider and Rockport Deferral regulatory assets;

ii. The Commission's authorization that the Company continue to accrue carrying charges at the Company's weighted average cost of capital until securitization bonds are issued; and

iii. The securitized bonds being issued.

If the Commission issues the requested financing order and the Company subsequently is unable to issue securitization bonds, collection of the regulatory assets through their respective rider mechanisms would be reinstated, as further described by Company Witness West.

This commitment will have several benefits for customers. First, it will provide lower customer bill impacts than would otherwise be the case beginning in January 2024 and continuing through the remaining winter billing months. It also will provide more certainty regarding the amounts of the Decommissioning Rider and Rockport Deferral Regulatory Assets that will be securitized. Finally, the suspension of rider collection until securitization occurs would not be detrimental to the Company's financial condition, as it would be cash flow neutral compared to 2023.

3. **<u>Postponing Depreciation Rate Updates</u>**. As part of the preparation for this filing, the Company analyzed updating its depreciation expense as a result of regulatory commission decisions regarding its interest in the Mitchell Generating Station ("Mitchell"). The Company's preliminary depreciation analysis reflected that updating depreciation rates in this proceeding would have resulted in an approximately $69 million annual increase in Mitchell depreciation expense for the next five years, to reflect that Kentucky Power's interest in Mitchell ends after 2028. Additionally, in late March 2023, the United States Environmental Protection Agency proposed supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (the "Proposed Supplemental ELG Rules"). The Company is analyzing the Proposed Supplemental ELG Rules and will evaluate the effect of any final rules on Mitchell. Balancing the need to update depreciation rates against the current economic conditions in the Company's service territory and the uncertainty concerning these potential additional environmental requirements affecting Mitchell, the Company determined it was appropriate to forgo updating its depreciation rates in this proceeding.

4. <u>Reduction to Storm Project Expense Level</u>. As discussed by Company Witness West, the Company is proposing to reduce the level of total distribution major and non-major storm project expense in the test year from $7.3 million to approximately $1.0 million, and maintain the actual test year level of transmission major and non-major storm project expense of $0.1 million, rather than propose an increase to expense to reflect the three-year average of actual expenses (excluding February 2021 Ice Storm and July 2022 Flood expenses), which would have equaled approximately $9.4 million.

5. Reduction of Recommended ROE. Company Witness McKenzie's ROE analysis demonstrates that a 10.6% ROE is warranted for the Company. Although Mr. McKenzie's analysis supports a higher ROE, Kentucky Power is requesting an ROE of 9.9% as a fifth way to reduce and offset the rate increase in this case.

Each of these measures represents a one-time proposal that Kentucky Power is making, without prejudice to the Company's positions in future rate cases, in recognition of the unique economic and financial challenges that customers in the Company's service territory are facing.

Q. IS THE COMPANY MAKING ANY OTHER CHANGES TO ITS EXISTING COST RECOVERY MECHANISMS?

A. Yes. As discussed further by Company Witness West, the Company is proposing to terminate its PJM LSE OATT cost tracking through Tariff PPA at this time. Until recently, it appeared that the Company would be in a different place to address the Commission's concerns raised in its Order in Case No. 2020-00174 related to transmission cost allocation to Kentucky Power. However, as a result of the recent change in circumstance, the AEP Service Corporation will be retaining a consultant to conduct an analysis of transmission cost allocation and its impacts on Kentucky Power and other AEP East Operating Companies, as detailed by Company Witness Burkholder. Until that process is complete, the Company is not seeking to continue tracking PJM LSE OATT costs through Tariff PPA.

Q. DID KENTUCKY POWER CONSIDER THE EFFECT OF ITS REQUESTED RATE INCREASE ON ITS CUSTOMERS?

A. Yes. Kentucky Power balances its operations and requests for rate relief with the circumstances facing customers, the need to continue to prudently invest in its distribution system to maintain and improve service reliability, and the Company's dire financial condition. It is with customers in mind that the Company is proposing the measures I describe above to offset and reduce its requested rate increase and the many customer-focused proposals this case.

Kentucky Power's request is reasonable and necessary to position the Company to meet the significant challenges it and its customers face and will allow it to continue to:

- provide reliable electric service to the communities it serves;
- maintain and improve reliability;
- invest in necessary capital improvements to the distribution system; and
- provide a safe work environment that sends each and every employee home injury-free.

Kentucky Power provides a valuable service to its customers and is a leader in the eastern Kentucky economy. The Company, however, is significantly challenged under its existing rates to continue to provide energy that is reliable, efficient, and consistent with customers' service expectations.

Q. ARE THERE OTHER OPTIONS THE COMPANY IS EXPLORING TO MITIGATE FUTURE CUSTOMER BILL IMPACTS?

A. The Company continues to explore all possible approaches to provide reliable power, in compliance with all applicable regulations, in the most cost-effective manner. The

Company is committed to continually review its operations and find more efficient and improved ways to achieve its core work providing electric service to customers. Ultimately, it is new jobs from economic development within the Company's service territory, and with it the associated increased load across which costs can be spread, that is the best opportunity Kentucky Power and its customers have to address the increasing cost of providing reliable, and efficient electric service. Kentucky Power remains deeply committed to leveraging economic growth opportunities represented by a highly skilled and available workforce in the eastern Kentucky region.

Q. ARE THE RATES REQUESTED BY KENTUCKY POWER FAIR, JUST, AND REASONABLE?

A. Yes. Kentucky Power's goal is to provide reliable and cost-effective service to its customers while also producing a reasonable return for its shareholders. The evidence is provided by the Company throughout its application for the Commission to review. Kentucky Power's proposed adjustments yield fair, just, and reasonable rates that will allow it to continue to provide the service that customers and KRS 278.030 require.

VIII. INTRODUCTION OF WITNESSES IN THIS CASE

Q. WHAT WITNESSES WILL BE OFFERING TESTIMONY IN SUPPORT OF KENTUCKY POWER'S APPLICATION, AND WHAT IS THE GENERAL SUBJECT MATTER OF THEIR TESTIMONY?

A. Kentucky Power is presenting 24 witnesses supporting the Company's proposals in this case. Table 1 below summarizes and introduces each witness and provides a brief description of their testimony:

Table 1: Kentucky Power's Witnesses

WITNESS	TOPICS
Cynthia G. Wiseman	Company Organizational Structure and Service Territory; The Company's Support of Customers, Eastern Kentucky; Current Challenges and the Need for this Case; Overview of Major Proposals and Measures to Reduce and Offset Customer Rate Impacts; and Identification and Introduction of the Company's Witnesses
Brian K. West	Proposed Revenue Requirement; Proposed Recovery of Winter Storm Elliott Purchase Power Costs; Distribution Reliability Rider Proposal; Prudency of the Company's Distribution Investment; Overview of Request for Securitization Financing Order; Total Estimated Amount to be Securitized; Discontinuing PJM LSE OATT Cost Tracking; and Amortization of Certain Other Deferrals
Steven Fetter	The Regulatory Compact and Need for Constructive Utility Regulation to Support Utility Credit Quality
Stevi Cobern	Kentucky Power's Focus on Customer Care; Proposal to Increase Residential Energy Assistance Surcharge to Increase Benefit Availability; and Proposal to Extend Customer Bill Payment Deadline
Amanda Clark	Kentucky Power's Investment in Economic Development and Kentucky Power Economic Growth Grant Program Continuation
Everett G. Phillips	Overview of Kentucky Power Distribution Programs; Annual Distribution O&M Expenses and Capital Investment; Vegetation Management Plan Funding; Kentucky Power's Smart Grid Investments; and Overview of Investments to be Recovered through the Proposed Distribution Reliability Rider
Stephen D. Blankenship	Prudency of Major Storm Costs Sought to be Securitized
Timothy C. Kerns	Overview of Kentucky Power Generation Assets; Description of Retired Generation Assets Comprising Decommissioning Rider Regulatory Asset; Generation Capital Investments Since Last Case; Test Year Generation O&M Expenses; and Operation of Kentucky Power Generation Assets During Winter Storm Elliott

WITNESS	TOPICS
Alex E. Vaughan	Prudency of Purchased Power Costs Above Peaking Unit Equivalent, Including Winter Storm Elliott Costs; Financial Power Hedging Proposal; and Distributed Solar (Solar Garden) Proposal
Adrien M. McKenzie	Calculation Of A Fair, Just, and Reasonable ROE Range
Franz D. Messner	Kentucky Power's Proposed Capital Structure; Cost of Capital For Ratemaking Purposes; Securitization Customer Benefits NPV Analysis; Proposed Securitized Bond Recovery Period; and Estimated Upfront and Ongoing Securitization Costs
Katrina T. Niehaus	Securitization Background; Proposed Securitization Transaction; Securitization Execution Process; and Key Elements of Financing Order and Transaction Documents
Michael M. Spaeth	Overview of the Relation Between the Company's Base Rates and its Surcharges and Riders; Rate Design; Certain Tariff Changes; Securitization Financing Rider; Estimated Amount of Securitized Surcharge; Semi-Annual Securitization Financing Rider True-Up; and Proposed Future Reconciliation Process
Katharine I. Walsh	Jurisdictional Cost-of-Service Study; and Calculation of Return on ADIT for Securitization Customer Benefits NPV Analysis
Jaclyn N. Cost	Class Cost-of-Service Study; and Allocation Of Requested Increase To Customer Classes
Heather M. Whitney	Certain Revenue And Operating Expense Adjustments; Requests for Deferral Accounting Authority Related to Certain Riders; and Certain Capitalization And Rate Base Adjustments
Linda M. Schlessman	Calculation Of Gross Revenue Conversion Factor; Jurisdictional State and Federal Income Taxes; Cost of Removal; Net Operating Loss Carryforward Normalization; Tax Effects Of Certain Ratemaking Adjustments; and Corporate Alternative Minimum Tax
Lerah M. Kahn	Environmental Surcharge Base Revenue Requirement; Certain Revenue and Operating Expense Adjustments; and Proposed Changes to Certain Tariffs

WITNESS	TOPICS
Scott E. Bishop	Certain Revenue and Operating Expense Adjustments
Andrew R. Carlin	Employee Compensation Strategy
Kamran Ali	Transmission Planning; Kentucky Power Transmission Investment; and Reasonableness of PJM LSE Costs
Joshua D. Burkholder	Overview of Kentucky Power's PJM Membership and Participation in the AEP Transmission Agreement; Kentucky Power's Transmission Expense and Revenues; and Compliance with Transmission Cost-Related Provisions of the Commission's Order in 2020-00174
Katherine Steward	Zero-Intercept Study
Michael Adams	Lead/Lag Study

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Cynthia G. Wiseman, being duly sworn, deposes and says she is the President and Chief Operating Officer for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Cynthia G. Wiseman

Cynthia G. Wiseman

Commonwealth of Kentucky)
)
County of Boyd)

Case No. 2023-00159

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Cynthia G. Wiseman, on June 26, 2023.

Scott E. Bishop

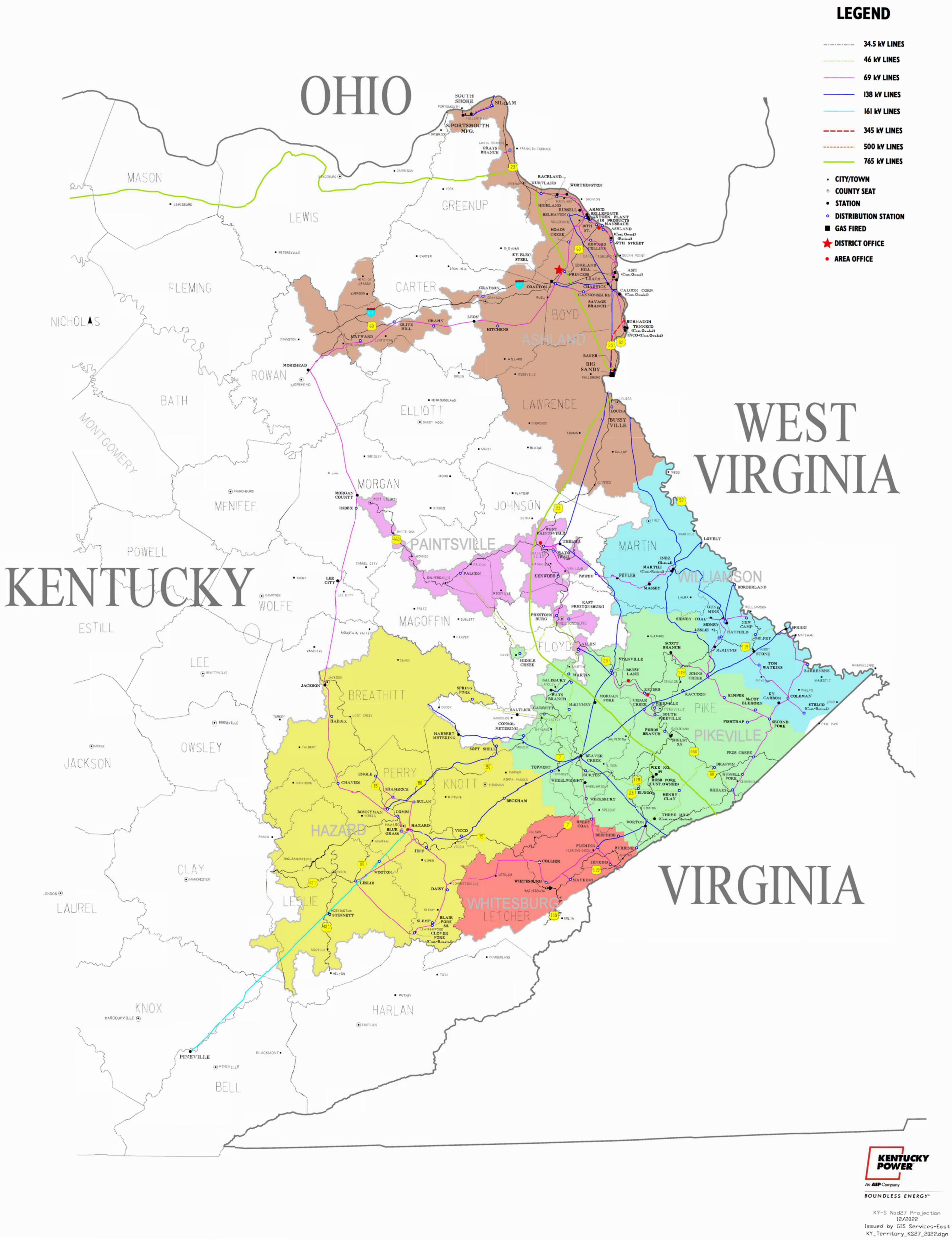
Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

Kentucky Power Service Area



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)	Case No. 2023-00159

DIRECT TESTIMONY OF

BRIAN K. WEST

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
BRIAN K. WEST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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DIRECT TESTIMONY OF
BRIAN K. WEST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Brian K. West. My position is Vice President, Regulatory & Finance for Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received an Associate's degree in Applied Science (Electronics Technology) and a Bachelor's degree in Business Management, both from Ohio University, in 1987 and 1988, respectively. I obtained a Master of Business Administration degree from Ohio Dominican University in 2008.

I began my utility industry career when I joined Ohio Power Company as a customer services assistant in Portsmouth, Ohio in 1989. This was a supervisor-in-training position, where I worked in each area of the office (e.g., cashiering, new service, and credit and collections) to gain knowledge and experience with every aspect of managing an area office. After completing the training program, I initially supervised meter readers in the Portsmouth office until being promoted to office supervisor in 1993. In 1997, when the area offices closed, I transferred to Chillicothe, Ohio and accepted the position of customer services field supervisor, with responsibility for managing customer field representatives who primarily worked with customers on high-bill and other inquiries.

In 2000, after American Electric Power Company ("AEP") merged with Central and South West Corporation, I moved to Columbus, Ohio, where I held various positions in Customer Operations, mostly in process improvement and supporting regulatory filings. In 2008, I transferred to AEP's Regulatory Services department, where I supported various filings before public service commissions in Arkansas, Indiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia, as well as the Public Service Commission of Kentucky ("Commission").

In 2010, I was promoted to regulatory case manager, with responsibility for energy efficiency/demand response filings, integrated resource plan filings, and various renewable filings across AEP's service territory. In 2016, I moved to a case manager role with primary responsibility for most Appalachian Power Company filings before the Public Service Commission of West Virginia, the Virginia State Corporation Commission, and the Tennessee Public Utility Commission. I accepted the position of Director of Regulatory Services for Kentucky Power in February 2019. I assumed my current position as Vice President, Regulatory & Finance for Kentucky Power Company in January 2021.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT, REGULATORY & FINANCE FOR KENTUCKY POWER?

A. I am primarily responsible for managing the regulatory and financial strategy for Kentucky Power. This includes planning and executing rate filings for both federal and state regulatory agencies, as well as filings for certificates of public convenience and necessity before this Commission. I am also responsible for managing the Company's financial operating plans. Included as part of this responsibility is the preparation and coordination of various capital and operation and maintenance ("O&M") budgets to ensure that adequate resources such as debt, equity, and cash are available to build, operate, and maintain Kentucky Power's electric system assets used to provide service to the Company's retail and wholesale customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have filed testimony in support of Kentucky Power's various regulatory filings since 2019. Most germane to my testimony in this case, I filed testimony in the Company's last base rate proceeding in Case No. 2020-00174, and the proposed transfer of ownership of Kentucky Power in Case No. 2021-00481.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support:

- Case organization and filing requirements;
- Proposed increase in annual revenues;
- Prudent distribution investment;
- Distribution Reliability Rider;
- Storm Expense in Base Rates;
- Request for securitization financing order;
- Discontinuing recovery of PJM LSE OATT costs through Tariff P.P.A.;
- Sale of Accounts Receivables;
- Depreciation Studies; and
- Amortization periods for certain other deferrals.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes, I am sponsoring the following schedules, which are located in Section V of the Company's Application:

- Schedule 1: Fully Adjusted Base Case Summary
- Schedule 2: Revenue Requirement

They provide details of the Capitalization and Rate Base amounts, as well as the Revenue Requirement.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

IV. CASE ORGANIZATION AND FILING REQUIREMENTS

Q. PLEASE DESCRIBE HOW THE COMPANY HAS ORGANIZED THE VARIOUS ELEMENTS OF THE CASE.

A. The case has been organized into the following components:

- Section I – Application;
- Section II – Minimum filing requirements in support of the Company's application in conformity with 807 KAR 5:001, Section 16 and 807 KAR 5:011, and other applicable provisions;
- Section III – Prepared testimony and exhibits in support of the Company's application in conformity with 807 KAR 5:001, Section 16;
- Section IV – Financial exhibit in the form prescribed by 807 KAR 5:001, Section 12. Balance sheet data is shown as of March 31, 2023, and income statement data is shown for the twelve months ended March 31, 2023; and

- Section V – Description and quantification of all proposed adjustments, with proper support for any proposed changes as prescribed by 807 KAR 5:001 Section 16.

Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S REGULATIONS REQUIRING CERTAIN ADDITIONAL DATA TO BE FILED?

A. Yes. The information required to be filed with a general rate case, including those requirements set forth in 807 KAR 5:001, Section 16 and 807 KAR 5:011, are presented in Section II (filing requirements) of the Company's filing, Section III (testimony), and Section V (adjustments).

V. PROPOSED INCREASE IN ANNUAL REVENUES

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT INCREASE BEING PROPOSED BY THE COMPANY.

A. The Company is proposing a total annual revenue requirement increase of $93,935,727. Section V, Schedule 2 shows how Kentucky Power derived the change in revenue requirement increase. The proposed annual revenue requirement increase represents approximately 13.6%, over the Test Year ended March 31, 2023 adjusted revenues of $694,002,526. The rates proposed by the Company are designed to produce $787,938,253 in annual revenues. Please refer to Section V, the Summary Tab, for the derivation of the proposed revenue requirement.

It is important to note that the Company is acutely aware of the systemic economic challenges across its service territory and, as explained further by Company Witness Wiseman, has taken significant steps to both manage and offset the Company's requests in this proceeding. For example, and explained in more detail in others' and my testimony, the Company is: proposing to securitize significant costs that would have otherwise been proposed to be recovered through base rates or currently-existing riders as part of this proceeding; conditionally proposing to suspend collection of the Decommissioning Rider and Rockport Deferral Regulatory Asset until securitization occurs; requesting a lower ROE as compared to that recommended by Company Witness McKenzie; proposing a program to offset some of the Company's contribution to the PJM AEP East Zone peak demand; foregoing an adjustment for major storm expense in base rates; and deferring updating depreciation rates. All of these efforts, as demonstrated throughout this filing, are intended to reduce bill impacts to customers in Kentucky Power's service territory. As such, the Company has limited its proposed rate increase to the minimum amounts necessary for the Company to continue to provide adequate and reliable service to its customers.

Q. DOES THE COMPANY'S PROPOSED REVENUE REQUIREMENT INCREASE INCLUDE NON-F.A.C. ELIGIBLE PURCHASED POWER EXPENSE RELATED TO DECEMBER 2022 WINTER STORM ELLIOTT?

A. No, it does not. As Company Witness Whitney explains, the Company adjusted test year non-F.A.C. eligible purchased power expense to exclude approximately $11.5 million of expense related to Winter Storm Elliott (the "Winter Storm Elliott PUE Expense"). The Company did so because, as of the date it finalized the revenue requirement for this filing to provide the requisite statutory notice of its requested rate increase in this case, the Company's application for authorization to establish a regulatory asset for the Winter Storm Elliott PUE Expense was pending before the Commission in Case No. 2023-00145.[1]

[1] In The Matter Of: Electronic Application Of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To The Extraordinary Fuel Charges Incurred By Kentucky Power Company In Connection With Winter Storm Elliott In December 2022, Case No. 2023-00145.

Q. PLEASE DESCRIBE THE SUBSTANCE OF THE COMPANY'S REQUEST IN CASE NO. 2023-00145.

A. Kentucky Power requested approval to establish the regulatory asset described above so that it could include the Winter Storm Elliott PUE Expense in the balance it seeks in this case to finance, to customers' benefit, through securitized bonds. Kentucky Power did not seek a prudency determination regarding the Winter Storm Elliott PUE Expense in that proceeding. Rather, the Company explained that it would present the deferred costs for Commission review and recovery in its securitization filing.

Q. DID THE COMMISSION APPROVE THE COMPANY'S REQUEST FOR DEFERRAL AUTHORITY IN CASE NO. 2023-00145?

A. No. On June 23, 2023, the Commission denied the Company's application for a regulatory asset for the Winter Storm Elliott PUE Expense, which means that the Company cannot recover them through the securitization statute, KRS 278.670, et seq.

Q. WHAT DOES THE COMPANY PROPOSE IN THIS CASE WITH RESPECT TO THE WINTER STORM ELLIOTT PUE EXPENSE?

A. The Company acknowledges that the Commission's June 23, 2023 Order in Case No. 2023-00145 questioned the prudency of the Winter Storm Elliott PUE Expense based on the record before the Commission in that case. Through the Direct Testimonies of Company Witnesses Vaughan and Kerns, Kentucky Power provides evidence in this proceeding that those costs were prudently and reasonably incurred. Due to the timing considerations described above, the Winter Storm Elliott PUE Expense was not included in the revenue requirement increase that the Company noticed in this case. Kentucky Power therefore respectfully requests, based upon the evidence supporting the prudency of the Winter

Storm Elliott PUE Expense presented in this case, that the Commission find those costs were prudently incurred. The Company further requests that the Commission include the Winter Storm Elliott PUE Expense in the revenue requirement approved in its final order in this case, up to the noticed total revenue requirement. To be clear, the Company is not requesting recovery of revenue above the amount included in its public notice in this case.

Q. WITH RESPECT TO THE WINTER STORM ELLIOTT PUE EXPENSE, ARE THERE ANY CONSIDERATIONS FOR KENTUCKY POWER'S NEXT BASE RATE CASE THAT THE COMPANY REQUESTS THAT THE COMMISSION ADDRESS IN THIS PROCEEDING?

A. Yes. The Company requests that the Commission authorize it to recover in the Company's next base rate case any prudently incurred Winter Storm Elliott PUE Expense not recovered through base rates approved in this proceeding.

Q. PLEASE SUMMARIZE THE DEVELOPMENT OF THE PROPOSED BASE CASE ANNUAL REVENUE REQUIREMENT PRESENTED IN SCHEDULE 1 OF SECTION V.

A. The development of the revenue requirement increase is shown on Schedule 1 (Fully Adjusted Base Case Summary) of Section V of the Company's filing. Schedule 1 summarizes the components of Net Electric Operating Income for the twelve months ended March 31, 2023, as adjusted, under present rates in Column 3, and the effects of the proposed rate increase on those components in Column 4. Also shown are the components of Net Electric Operating Income after giving effect to the proposed rate increase in Column 5. The total amount of rate base and capitalization is also shown, along with the calculated overall rates of return.

Q. PLEASE DESCRIBE THE INFORMATION PROVIDED BY SCHEDULE 1 (RATE BASE) OF SECTION V.

A. Schedule 1 shows the Company's development of the adjusted rate base amount used to develop the base case annual revenue requirement.

VI. PRUDENT DISTRIBUTION INVESTMENT

Q. HAS THE COMPANY'S HISTORICAL INVESTMENT IN ITS DISTRIBUTION SYSTEM BEEN QUESTIONED RECENTLY?

A. Yes. Kentucky Power's investment in its distribution system was highlighted by Liberty Utilities Company ("Liberty") in the recent case concerning the application to approve the sale of Kentucky Power to Liberty in Case No. 2021-00481[2] ("Transfer Case"). In the Transfer Case, Liberty averred that Kentucky Power's ratio of annual capital additions to depreciation expense was below those of other large utilities, and particularly, below the "2.0 multiple that is seen in the industry as a minimal measure of capital replenishment for a power utility."[3] Liberty also "made the working assumption"[4] that the level of capital investment in the distribution system also affected reliability metrics.

After Liberty injected this perceived issue into the Transfer Case, Attorney General and KIUC ("AG-KIUC") Witness Lane Kollen picked up on the idea by also asserting that Kentucky Power underinvested in its distribution system based on the amount of annual plant investment as a multiple of depreciation expense that was created by Liberty.

[2] In The Matter Of: Electronic Joint Application Of American Electric Power Company, Inc., Kentucky Power Company And Liberty Utilities Co. For Approval Of The Transfer Of Ownership And Control Of Kentucky Power Company, Case No. 2021-00481.
[3] *Id.; see* Liberty's response to KIUC 1-76(a)(ii) (January 24, 2022).
[4] *Id.*

Q. HAS THE COMPANY BEEN ABLE TO IDENTIFY A TWICE DEPRECIATION EXPENSE CAPITAL INVESTMENT INDUSTRY STANDARD?

A. No. The Company has not been able to identify that any such standard exists that either recommends or requires two times the distribution capital investment as compared to depreciation expense. The Company also confirmed this with AEP, which owns and operates seven electric utilities in 11 states.

Q. DID THE COMPANY THEN, AND DOES IT NOW, AGREE THAT THE BENCHMARK FOR DISTRIBUTION INVESTMENT ASSERTED BY LIBERTY AND AG-KIUC IS AN "INDUSTRY STANDARD"?

A. Again, no. Both Liberty and AG-KIUC relied on an arbitrary metric to incorrectly conclude that Kentucky Power should have invested more in its distribution system. Kentucky Power found itself in a unique position as a joint applicant with Liberty in the Transfer Case and did not have an opportunity to, nor would it have been appropriate to, challenge the metrics that Liberty characterized as "industry standard."

Q. DID LIBERTY OR AG-KIUC PROPERLY TAKE INTO ACCOUNT THE COMPANY'S UNIQUE SERVICE TERRITORY WHEN ASSERTING THAT KENTUCKY POWER DID NOT PROPERLY INVEST IN ITS DISTRIBUTION SYSTEM?

A. No. Liberty and AG-KIUC compared Kentucky Power's historical level of distribution investment to AEP-owned utilities in the aggregate and to other investor-owned utilities, including those in Kentucky. Kentucky Power's service territory is uniquely situated both economically and topographically. Liberty, which has no experience operating an electric utility in Appalachian Kentucky, could not have reliably determined based on transaction due diligence whether Kentucky Power's distribution investment practices were imprudent. Kentucky Power, both in the Transfer Case and in this case, has shown that the Company has prudently invested in its distribution system. This is particularly true when considering the Company's service territory, which requires not only special consideration of the terrain as described in the Direct Testimony of Company Witness Phillips, but also considered balancing of the economic situation of the service territory and customer affordability, which this Commission has acknowledged and emphasized in the Company's last several base rate cases.

Q. WHAT ARE THE COMPANY'S ACTUAL PAST RATIOS OF ANNUAL DISTRIBUTION CAPITAL INVESTMENT TO ANNUAL DISTRIBUTION DEPRECIATION EXPENSE?

A. In every year since 2010, the ratio of annual distribution capital investment to annual distribution depreciation expense has been greater than 1.0, which indicates investment in the Company's distribution system that exceeds the annual level of depreciation expense. In several years, the ratio was greater than 2.0. Figure BKW-1 below illustrates this fact.

Figure BKW-1

Year	Annual Distribution Capital Investment	Annual Distribution Depreciation Expense	Annual Distribution Capital Investment / Annual Distribution Depreciation Expense
2010	$28,812,376	$20,334,118	1.4
2011	$30,062,769	$21,060,489	1.4
2012	$49,856,794	$22,040,399	2.3
2013	$49,458,423	$23,769,486	2.1
2014	$41,494,584	$24,860,701	1.7
2015	$38,204,061	$26,054,977	1.5
2016	$36,074,051	$26,947,717	1.3
2017	$39,656,169	$27,880,463	1.4
2018	$44,254,606	$28,993,519	1.5
2019	$63,742,091	$30,374,261	2.1
2020	$68,428,958	$32,682,142	2.1
2021	$72,435,107	$34,631,574	2.1
2022	$54,976,028	$36,408,097	1.5

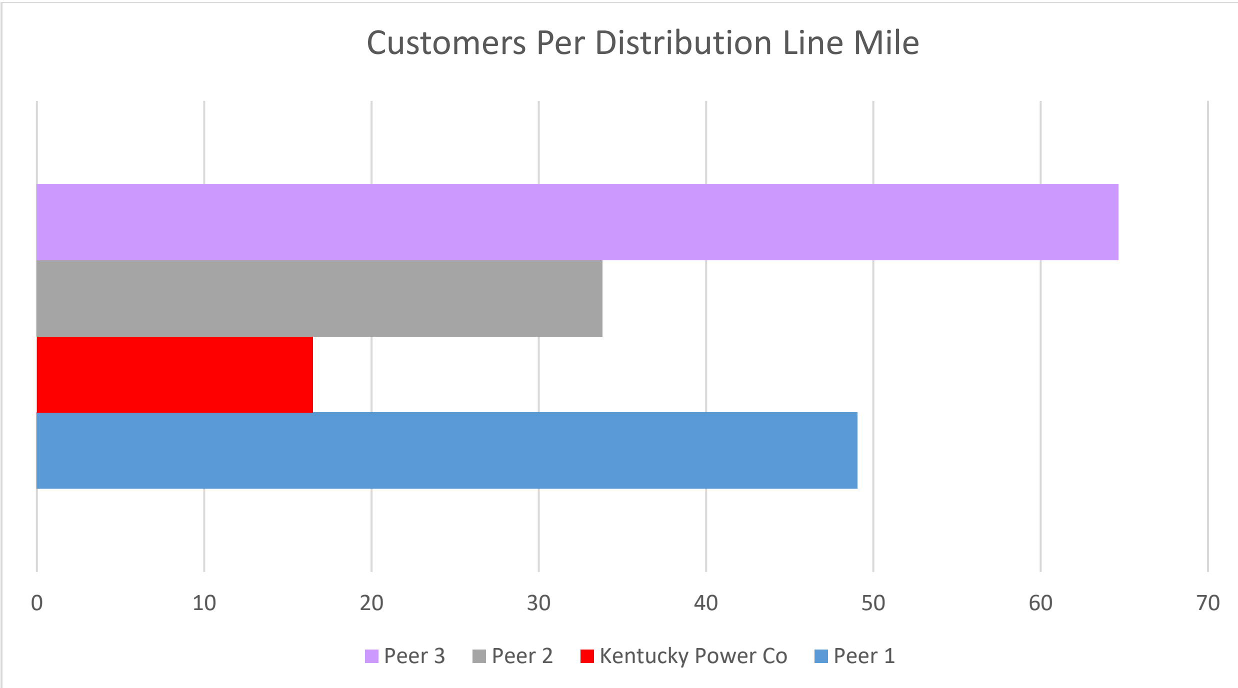
Q. SHOULD THE COMPANY HAVE MAINTAINED EVERY YEAR A RATIO OF ANNUAL DISTRIBUTION CAPITAL INVESTMENT TO ANNUAL DEPRECIATION EXPENSE EQUAL TO OR GREATER THAN 2.0?

A. No. First, as I previously stated, the Company has no reason to believe the 2.0 metric used by Liberty and AG-KIUC in the Transfer Case is an industry standard. Moreover, the combination of the circumstances surrounding Kentucky Power's service territory and related operating challenges, which are explained further by Company Witness Phillips, make the Company an outlier as compared to other utilities. Furthermore, requiring Kentucky Power to arbitrarily invest capital at a ratio of 2.0 or greater in order to prove that it has not underinvested would have significant cost impacts on customers, particularly residential customers.

As a general rule, residential customers are allocated the greatest share of distribution costs because they take service at distribution voltages. Kentucky Power residential customers are more sensitive to increases in distribution investment compared to the other investor-owned utilities ("IOUs") in the Commonwealth. As demonstrated by Company Witness Clark, the Company's service territory has experienced a significant reduction in customer count since 2010, while the other Kentucky IOUs have experienced customer growth. The reduction in customers means there are fewer customers among which to spread the cost of distribution investment, resulting in higher costs per customer. The simple ratio of capital/depreciation expense championed in the Transfer Case does not factor that in. Customer growth also naturally results in the need to make incremental capital investment to serve new load, thereby resulting in an increase in the ratio, as the numerator of that equation (capital investment) increases as compared to the denominator (depreciation expense).

Additionally, as compared to the other IOUs in the Commonwealth and shown below in Figure BKW-2, the Company also has significantly fewer customers per line mile. Company Witness Phillips also supports this fact in his Direct Testimony. This statistic also demonstrates that the Company has fewer customers over which to spread the costs of additional investments, resulting in a higher financial impact of such investments on a per customer basis compared to the other Kentucky IOUs.

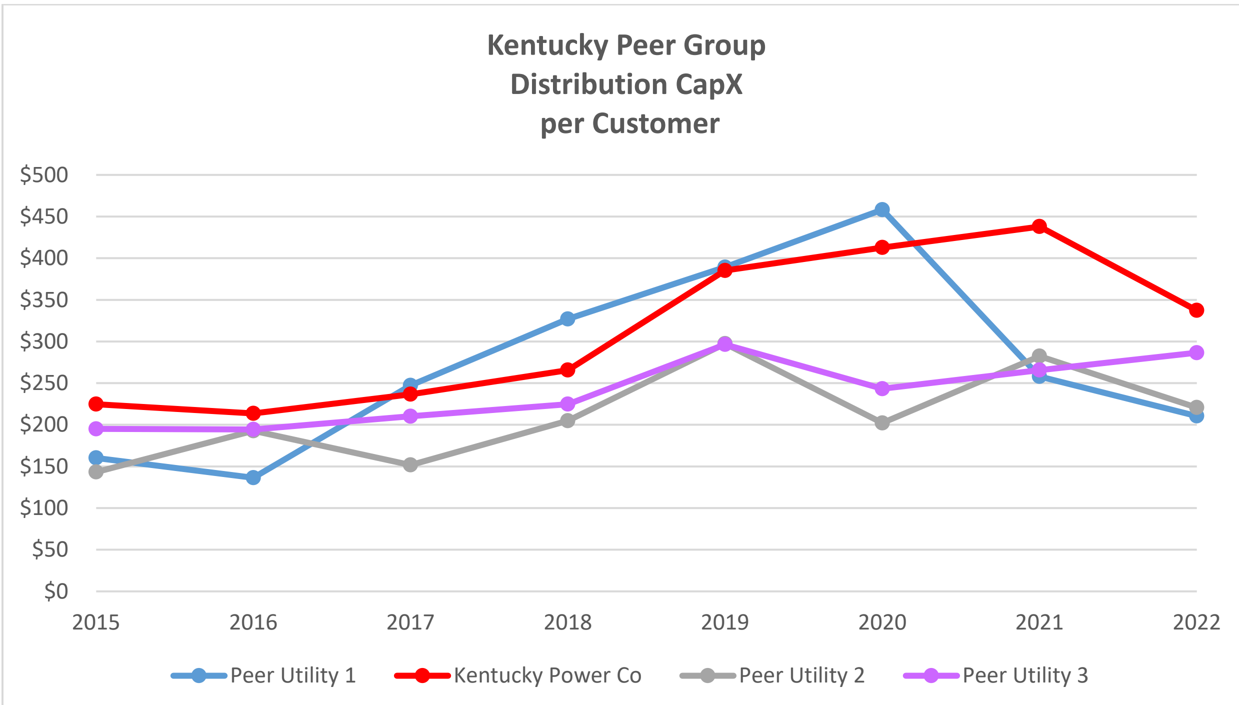
Figure BKW-2



The Company must make necessary investments to ensure that it is able to continue to provide adequate and reliable service to customers, while also remaining cognizant of the challenging economic conditions in Eastern Kentucky. Making the determination of whether the Company has prudently invested in its distribution system by looking only at capital expenditures versus depreciation is too simplistic and does not account for important operating considerations and service territory demographics. When analyzing the Company's investment in its distribution system, it is important to consider investment on a per-customer and customer-per-line mile basis. Comparing the level of capital invested per customer is a way to normalize the data in a manner that also appropriately takes into account the cost impact on customers of a utility's investment.

As shown in Figure BKW-3, Kentucky Power has generally invested more capital per customer in its distribution system as compared to its Kentucky peers since at least 2015. To say that the Company has underinvested in its distribution system because it has not invested capital above an arbitrary 2.0 ratio ignores the fact that Kentucky Power customers are already paying more per capita than the customers of the other IOUs in the Commonwealth.

Figure BKW-3



Thus, the normalized data demonstrates that Kentucky Power's investment in its distribution system has been prudent and appropriate based on several influential factors, and that there has not been underinvestment in the Company's distribution system.

Q. ARE THERE ADDITIONAL FACTS THAT DEMONSTRATE THE COMPANY HAS NOT UNDERINVESTED IN ITS DISTRIBUTION SYSTEM?

A. Yes. As explained further by Company Witness Phillips, the Company's number one cause of outages are trees outside the rights-of-way ("TOR"), and that outage cause cannot be solved by distribution equipment investment.

Q. HAS THE COMPANY NONETHELESS TAKEN STEPS TO ADDRESS TOR OUTAGES?

A. Yes. In 2018, the Company began a rights-of-way widening pilot program to specifically address TOR outages, which has resulted in fewer outages from TOR in the areas addressed. The Company plans to continue and expand that program across its service territory and expects to realize similar reliability improvements in its remaining districts.

As detailed below, the Company is proposing to expand its TOR program and to address other major reliability opportunities over the next several years by establishing a distribution work plan that it will present annually for Commission review and approval. This approach will enable the Company and the Commission jointly to carefully balance the need to make system improvements with the cost of those improvements, among other considerations. To facilitate this program, the Company is proposing a new capital rider, the Distribution Reliability Rider ("DRR"), which will include an appropriate amount of capital spend to address the major reliability drivers included in the Company's approved DRR Work Plan.

VII. DISTRIBUTION RELIABILITY RIDER

Q. PLEASE GENERALLY DESCRIBE THE PURPOSE OF THE DISTRIBUTION RELIABILITY RIDER.

A. The DRR is the proposed recovery mechanism for new distribution reliability projects to be implemented as part of a proposed DRR Work Plan. The proposed projects that will be part of the DRR Work Plan will improve reliability for the Company's customers. The Company proposes this incremental cost recovery mechanism in order to make further investment in its distribution system possible, particularly given the Company's current financial condition and cash flow constraints. Company Witness Phillips describes the DRR Work Plan and the initial projects the Company proposes to include therein in his testimony. Company Witness Spaeth supports the DRR's rate design.

Q. CAN YOU ILLUSTRATE THE PROPOSED OPERATION OF THE DRR?

A. Yes. As presented by Company Witness Phillips, the initial DRR Work Plan is projected over a five-year period, beginning in 2024. The Company's projected first year (2024) DRR Work Plan includes approximately $19 million in capital investments, and incremental O&M associated with the Company's Distribution Asset Management and Major Distribution Reliability and Capacity Addition programs. This cost projection will be trued-up to actual spending in an annual filing. A projection of the following year's investment will be included in the annual true-up filing as well as over- or under-recovery for actual spending in the prior year so that customers are assured of paying for only the actual costs of DRR programs. The Company proposes to make the annual true-up filing in February each year, with rates becoming effective with cycle 1 of the following April billing period, to reconcile the amount collected through the rider in the previous year with the past year's actual spend. The DRR will have an initial "zero start" with initial rates for the 2024 work described above designed to take effect in April 2025 (after winter when rates typically are at their highest), after the first annual DRR filing in February 2025. The February 2025 annual DRR filing also will include a revised annual DRR Work Plan.

Q. WHAT HAPPENS TO THE DRR WHEN KENTUCKY POWER FILES FUTURE BASE RATE CASES?

A. The Company would propose in each future base rate case to roll any then-existing DRR revenue requirement into base rates. At that point, there would be a basing point for DRR costs included in base rates and any incremental costs would continue to be recovered through the DRR going forward until included in base rates in the next base rate case filing. The Company's current Environmental Surcharge functions in the same manner.

Q. PLEASE EXPLAIN WHY A RIDER IS NECESSARY TO RECOVER THE PROPOSED COSTS OF THE DRR WORK PLAN.

A. Traditionally, riders are used to recover costs that are more volatile in nature and occur over a relatively short period of time. They also ensure that customers pay no more, nor less, than the actual cost, while providing the Commission a more frequent opportunity to review project status and costs through the annual true-up filings. The DRR will provide the Company with the ability to propose new projects in an annual DRR Work Plan for Commission review in the annual filings rather than waiting for the next base rate case. Projects that will benefit customers with improved reliability and resiliency and help to modernize the distribution grid will be brought in-service more quickly with more transparency than is possible through base rate case filings. By approving the implementation of the DRR, the Commission would be authorizing a cost recovery mechanism that also will help Kentucky Power improve its financial position with more concurrent cost recovery than traditional base rate case filings, while making necessary distribution system improvements. Further, smaller incremental rate increases through annual true-up filings, like with the Company's other riders, will smooth out rate increases making them more manageable for customers.

Q. IS THE COMPANY PROPOSING AS PART OF ITS DRR WORK PLAN TO IMPLEMENT ADVANCED METERING INFRASTRUCTURE ("AMI") METERS AT THIS TIME?

A. No, the Company is not proposing to implement AMI meters as part of its DRR Work Plan at this time.

Q. PLEASE EXPLAIN WHY THE COMPANY IS NOT SEEKING TO IMPLEMENT AMI METERS AT THIS TIME.

A. At the time of the Company's last base rate case in 2020, there was a need to implement AMI meters. However, that need has since been alleviated, at least for now. The Company currently has access to an adequate inventory of automated meter reading ("AMR") meters to continue using those meters to supply adequate and sufficient service to customers. The Company anticipates having this access at least in the short term, and implementing AMI meters is not necessary during this time. This is because the COVID-19 Pandemic disrupted supply chains and caused manufacturing delays to the production of new AMI meters, which led to lead times of at least 52 weeks for the production of new AMI meters. To help alleviate the long lead times for AMI meters, third-party companies began offering the service of refurbishing AMR meters, which were then made available for purchase by companies in the electric utility industry. Since 2022, Kentucky Power has been able to take advantage of one such offering from Vision Metering, LLC., and can purchase refurbished AMR meters as needed. Taking advantage of these refurbished AMR meters has benefitted customers by extending the life of the current meters and delaying the investment to upgrade to AMI meters when necessary.

It must still be noted that AMR meters only have an engineered design life of 15 years and refurbishing existing AMR meters does not extend the life of those meters. Currently, 75% of the Company's AMR meters are beyond their 15-year engineered design lives. Additionally, the Company's current systems can only accommodate the refurbished AMR meters, which are an older model of AMR meters. As Company Witness Blankenship explained in the Company's last base rate case, if the Company wanted to use the newer model of AMR meters, its systems would need to be upgraded, which would take a significant capital investment to complete. For these reasons, replacing AMR meters with AMI meters, when it becomes necessary to do so, remains on the Company's longer-term planning horizon.

VIII. STORM EXPENSE IN BASE RATES

Q. PLEASE EXPLAIN HOW KENTUCKY POWER TRADITIONALLY SETS A NORMALIZED LEVEL OF STORM EXPENSE FOR ITS BASE RATES.

A. In the last several rate cases, Kentucky Power adjusted its test year distribution major storm damage expense by using a historical three-year average of distribution major storm damage expense, less in-house labor, and adjusted by the Handy-Whitman Contract Labor Index. The actual level of test year distribution non-major storm damage expense, as well as the actual level of test year transmission major and non-major storm damage expense, remained in the test year, unadjusted. In the Company's prior base case, the amount of distribution and transmission major and non-major storm project expense included in the base rate revenue requirement was approximately $2.1 million (composed of $1.0 million distribution major storm project expense, $1.1 million distribution non-major storm project expense, and $0.003 million of transmission major and non-major storm project expense).

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THIS METHODOLOGY?

A. Yes, the Company has streamlined its adjustment calculation methodology by including total expense for both major and non-major storm projects in (1) identification of the actual test year expense per books of $7.3 million[5] for distribution and $0.1 million for transmission and (2) computation of an updated three-year average level of distribution and transmission expense of $30.1 million. In addition, as a mitigation effort in this case, the Company is proposing to reduce the level of total distribution major and non-major storm project expense in the test year from $7.3 million to approximately $1.0 million, and maintain the actual test year level of transmission major and non-major storm project expense of $0.1 million, rather than propose an increase to expense to reflect the three-year average of actual expenses (excluding February 2021 Ice Storm and July 2022 Flood expenses), which would have equaled approximately $9.4 million. Due to the relatively low level of distribution and transmission major and non-major storm project expense proposed to be established in base rates, going forward, the Company would need to file an application(s) seeking deferral accounting authority when it had distribution and transmission major and non-major storm project expense that exceeds the $1.1 million baseline.

IX. <u>REQUEST FOR SECURITIZATION FINANCING ORDER</u>

Q. HAS SECURITIZATION BEEN ENACTED INTO LAW IN KENTUCKY?

A. Yes, it has very recently. Kentucky Power worked collaboratively with interested stakeholders to make securitization possible in Kentucky. After discussion in prior cases

[5] Actual test year distribution storm expense per books of $7.3 million is composed of $5.4 million associated with major storm projects and $1.9 million associated with non-major storm projects.

with intervenors like the Attorney General and Kentucky Industrial Utility Customers, Inc., Kentucky Power lobbied the Kentucky General Assembly to enact a law allowing securitization for Kentucky Power customers' benefit. A securitization bill was introduced as part of the 2023 general legislative session ("Senate Bill 192") and Governor Beshear signed it into law on March 23, 2023. Senate Bill 192 became effective 90 days after the 2023 general legislative session ended on March 30, 2023.[6]

Q. WHAT COSTS ARE ELIGIBLE FOR SECURITIZATION UNDER SENATE BILL 192?

A. Senate Bill 192 allows an electric utility to apply to the Commission for a financing order to finance extraordinary or other deferred costs from previous events for regulatory assets existing and with a value calculated on June 30, 2023, as:

(a) Greater than two hundred million dollars ($200,000,000) for a single regulatory asset; or

(b) Having a cumulative total value of greater than two hundred and seventy-five million ($275,000,000) for multiple regulatory assets.[7]

The law further details that "'securitized costs' include generation costs, as well as the unamortized book value of extraordinary storm costs or other deferred costs associated with prior incurrences but does not include ongoing utility investments or operating costs."[8]

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[6] See KRS 278.670 through 278.696.
[7] KRS 278.672(1).
[8] KRS 278.670(18).

Q. CAN YOU PLEASE DESCRIBE THE REGULATORY ASSETS THAT KENTUCKY POWER SEEKS TO SECURITIZE?

A. Yes. Kentucky Power seeks to finance the entirety of the following regulatory assets with a cumulative total value of approximately $471.2 million by using securitized bonds. Those regulatory assets are detailed as follows in Figure BKW-4:

Figure BKW-4

Line No.	Regulatory Asset Description	Case No.	FERC Subaccount(s)	Expected Balance as of June 30, 2023
1	**Decommissioning Rider Regulatory Asset**	Please Refer to Application Exhibit 4	1823376	**$ 289,193,517**
2			1823378	
3			1823379	
4			1823380	
5			1823517	
6			1823518	
7	January 2020 Wind Storm	2020-00368	1823620	$ 646,479
8	April 2020 Thunderstorm			$ 474,856
9	April 2020 Wind Storm			$ 9,843,199
10	December 2020 Snow Storm	2021-00135		$ 1,043,892
11	2020 Storm Incremental O&M			$ 12,008,426
12	Less: Amount in Base Rates			$ (1,498,582)
13	**2020 Storm Expense Deferral Regulatory Asset**			**$ 10,509,844**
14	February 2021 Ice and Snow Storms	2021-00129	1823623	$ 46,199,297
15	February 2021 Major Flood	2021-00402		$ 826,495
16	2021 Storm Incremental O&M			$ 47,025,792
17	Less: Amount in Base Rates			$ (1,029,789)
18	**2021 Storm Expense Deferral Regulatory Asset**			**$ 45,996,003**
19	June 2022 Thunderstorm and Wind Storm	2022-00293	1823698	$ 3,401,582
20	July 2022 Historic Flood			$ 11,449,177
21	2022 Storm Incremental O&M			$ 14,850,759
22	Less: Amount in Base Rates			$ (1,012,476)
23	**2022 Storm Expense Deferral Regulatory Asset**			**$ 13,838,283**
24	March 2023 Wind Storm (March 3, 2023)	2023-00137	1823722	$ 3,295,455
25	March 2023 Wind Storm (March 25, 2023)			$ 1,028,326
26	April 2023 Wind Storm			$ 5,643,197
27	2023 Storm Incremental O&M - Estimate			$ 9,966,978
28	Less: Amount in Base Rates			$ (1,012,476)
29	**2023 Storm Expense Deferral Regulatory Asset - Estimate**			**$ 8,954,502**
30	**Rockport Deferral Regulatory Asset**	2017-00179 2020-00174 2022-00283	1823430 1823431	**$ 52,253,087**
31	**Tariff P.P.A. Under-Recovery Regulatory Asset (Under-Recovered Since January 2020)**	2017-00179 2020-00174 2022-00416	1823557	**$ 50,453,564**
32	**Total Regulatory Assets Requested for Securitization**			**$ 471,198,800**

Company Witness Kerns provides a description of Big Sandy Unit 2, which is the retired generating facility subject to securitization in this filing. Copies of all previous Commission orders related to the Decommissioning Rider Regulatory Asset are attached to the Company's Application as Exhibit 4.

Because June 2023 Tariff D.R. and Tariff P.P.A. revenues and expenses are not known at the time of this filing, amounts reported in Figure BKW-4 for the Decommissioning Rider Regulatory Asset and Tariff P.P.A. Under-Recovery Regulatory Asset represent May 2023 actual balances.

The amount reported in Figure BKW-4 for the 2023 Storm Expense Deferral Regulatory Asset represents the estimated regulatory asset balance, as provided to the Commission in Case No. 2023-00137.[9] The Company will file its actual costs associated with the March and April 2023 storms on or before September 30, 2023, in Case No. 2023-00137.

Q. WILL EACH OF THE ABOVE REGULATORY ASSETS EXIST ON KENTUCKY POWER'S BOOKS AS OF JUNE 30, 2023?

A. Yes.

Q. DO EACH OF THE ABOVE REGULATORY ASSETS MEET THE CRITERIA TO BE SECURITIZED UNDER SENATE BILL 192?

A. Yes. The Decommissioning Rider Regulatory Asset is comprised entirely of retired generation costs.[10] Each of the storm regulatory assets are comprised entirely of

[9] In The Matter Of: Electronic Application Of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To The Extraordinary Expenses Incurred By Kentucky Power Company In Connection With The March 3, 2023, March 25, 2023, And April 1, 2023 Major Event Storms, Case No. 2023-00137.

[10] *Id.*

extraordinary storm costs.[11] Each of the Rockport Deferral Regulatory Asset and the Tariff P.P.A. Under-Recovery Regulatory Asset are comprised entirely of other deferred costs that are not ongoing utility investments or operating costs.[12]

Q. HAS THE COMMISSION AUTHORIZED THE RECOVERY OF EACH OF THOSE REGULATORY ASSETS?

A. The Commission has reviewed and authorized the Company to amortize and recover the following regulatory assets: Decommissioning Rider Regulatory Asset, Rockport Deferral Regulatory Asset, and Tariff P.P.A. Under-Recovery Regulatory Asset.

The Commission has authorized the Company to establish regulatory assets for but has not yet authorized the recovery of the storm regulatory assets listed above.

Q. WERE ALL OF THE AMOUNTS THAT MAKE UP EACH REGULATORY ASSET THAT HAS NOT YET BEEN APPROVED FOR RECOVERY REASONABLY AND PRUDENTLY INCURRED?

A. Yes. In this proceeding, the Company has demonstrated that the regulatory assets were prudently incurred and appropriately included as part of its securitization request herein. Company Witness Blankenship supports the reasonableness and prudency of the costs that make up each of the storm regulatory assets.

Q. WHAT IS THE TOTAL ESTIMATED AMOUNT TO BE SECURITIZED?

A. The total estimated amount to be securitized, including upfront financing costs and net of a credit for the return on accumulated deferred income taxes associated with the Decommissioning Rider and Rockport Deferral Regulatory Assets, is approximately $446.7 million, as described by Company Witness Messner.

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[11] *Id.*
[12] *Id.*

Q. ARE THE ISSUANCE OF THE SECURITIZED BONDS AND THE IMPOSITION OF THE PROPOSED SECURITIZATION FINANCING EXPECTED TO PROVIDE QUANTIFIABLE NET PRESENT VALUE BENEFITS TO CUSTOMERS?

A. Yes. Company Witness Messner demonstrates, pursuant to KRS 278.672(2)(f), that the issuance of securitized bonds and the imposition of securitized surcharges are expected to provide a quantifiable net present value ("NPV") benefit to customers compared to the cost that would result from an alternative means of providing for the full recovery of and return on those securitized costs from customers using the Company's proposed weighted average cost of capital. Based on current market conditions, Company Witness Messner calculates a positive net NPV of approximately $74 million under the statutory test.

Q. WHAT IS THE ESTIMATED SECURITIZED SURCHARGE?

A. As Company Witness Spaeth explains, the estimated securitized surcharge will be allocated to Residential and All Other Non-Residential Customers based on total retail revenue and assessed to both customer groups as a percentage of retail revenue at the following rates:

Residential SFR Factor: 5.8233%

All Other SFR Factor: 11.440%.

Q. IS THE COMPANY'S APPLICATION FOR A SECURITIZATION FINANCING ORDER IN THE PUBLIC INTEREST, AND WILL THE RESULTING SECURITIZED SURCHARGE RESULT IN RATES THAT ARE FAIR, JUST, AND REASONABLE?

A. Yes. Approval of a securitization financing order would reduce rates for customers by financing these prudently incurred regulatory assets at a long-term debt interest rate, and over a longer period of time than would be the case absent securitization. For example, historically storm costs would be recovered over a considerably shorter time period than the 20-year securitization period, typically over 3 to 5 years. Further, it also would give the Company access to capital that can be deployed elsewhere over a comparable time horizon.

Q. HOW WILL THE COMPANY RECOVER SECURITIZATION FINANCING COSTS?

A. The Company is proposing a Securitization Financing Rider to recover those costs. The Securitization Financing Rider's monthly cost would appear as a separate line item on customers' bills. The Company's proposed Securitization Financing Rider is supported by Company Witness Spaeth.

Q. WILL THERE BE TRUE-UP FILINGS FOR THE SECURITIZATION FINANCING RIDER?

A. Yes. KRS 278.676(1)(f), requires that at least annually, the Company must propose periodic adjustments to the securitized surcharge that customers are required to pay pursuant to the financing order. This is necessary to correct for any over- or under-collection of the surcharge and ensure the timely payment of securitized bonds and financing costs. The Company proposes to make semi-annual true-up filings, as set forth in the tariff sponsored by Company Witness Spaeth. As explained by Company Witness Niehaus, it is important that the semi-annual true-up filings are sufficiently offset from the securitized bond payment dates. Accordingly, the Company plans to file a future tariff filing update to the Securitization Financing Rider after the securitized bond payment dates are known. The Company will provide sufficient statutory notice to the Commission of that change.

Q. PLEASE EXPLAIN THE TIMING OF ANY PLANNED APPLICATIONS FOR APPROVAL OF CONTRACTUAL AGREEMENTS RELATED TO THE COMPANY'S PROPOSED SECURITIZATION TRANSACTION.

A. As Company Witness Niehaus explains, a Purchase and Sale Agreement and a Servicing Agreement between Kentucky Power and a to-be-created, wholly-owned subsidiary special purpose entity ("SPE") will support the issuance and govern the servicing of the securitized bonds, respectively. I am advised by counsel that both agreements are subject to Commission approval pursuant to KRS 278.2207, and that the Purchase and Sale Agreement also requires Commission approval under KRS 278.218. If the Company's request for a financing approval is approved in this proceeding, the Company will file an application for Commission approval of both agreements.

Q. HOW DOES THE COMPANY PLAN TO ADDRESS THE REGULATORY ASSETS THAT ARE THE SUBJECT OF ITS SECURITIZATION PROPOSAL IF THE COMMISSION DECLINES TO APPROVE THEIR SECURITIZATION?

A. If the Commission determines that any of the above-mentioned regulatory assets should not be securitized, the Company will continue recovering the Decommissioning Rider Regulatory Asset, Rockport Deferral Regulatory Asset, and Tariff P.P.A. Under-Recovery Regulatory Asset through those regulatory assets' existing recovery mechanisms. The Company will pursue amortization of the storm regulatory assets in its next base rate case. In that event, because the Company will have been carrying the storm regulatory assets on its books for multiple years, the Company also requests that the Commission include specific ordering language authorizing it to accrue a carrying charge on those regulatory assets at the weighted average cost of capital authorized in this proceeding.

X. RECOVERY OF PJM LSE OATT CHARGES

Q. HOW DOES THE COMPANY CURRENTLY RECOVER ITS FERC-APPROVED WHOLESALE COSTS?

A. Company Witness Burkholder explains at a high level the process under FERC-regulated rates to determine Kentucky Power's wholesale costs (i.e., Kentucky Power's Load Serving Entity ("LSE") costs under PJM's Open Access transmission Tariff ("OATT") and the AEP Transmission Agreement).

At a retail level, Kentucky Power currently recovers an annual amount of PJM LSE OATT costs through base rates ($96,896,495). The Company recovers or credits through Tariff P.P.A. 100% of the net annual amount of PJM LSE OATT costs above or below the annual amount in base rates, less the transmission return difference pursuant to the Commission approved Settlement Agreement in the Company's 2017 base rate case (Case No. 2017-00179).

Q. HOW HAS THE COMPANY PREVIOUSLY RECOVERED THESE COSTS?

A. Prior to the Company's 2017 base rate case, Kentucky Power recovered an annual amount of PJM LSE OATT charges entirely through base rates. Beginning with the Company's 2017 base rate case, the Commission accepted as part of the settlement agreement in that case the parties' proposal to allow Kentucky Power to recover through Tariff P.P.A. 80% of the net annual amount of PJM LSE OATT charges over or above the annual amount in base rates.

In the Company's 2020 base rate case (Case No. 2020-00174), the Commission granted Kentucky Power's request to recover through Tariff P.P.A. 100% of PJM LSE OATT expenses over or above the amount in base rates "until the next rate case, when the issue [would] be re-examined."

Q. HOW DOES KENTUCKY POWER PROPOSE TO RECOVER THESE COSTS GOING FORWARD?

A. Kentucky Power proposes to discontinue recovery of PJM LSE OATT charges through Tariff P.P.A. and proposes to recover an annual amount of PJM LSE OATT charges entirely through base rates.

XI. SALE OF ACCOUNTS RECEIVABLES

Q. WHEN DID KENTUCKY POWER BEGIN SELLING ITS ACCOUNTS RECEIVABLE?

A. In 2000, AEP merged with Central and South West Corporation and soon after in April 2001, Kentucky Power began selling its accounts receivable.

Q. WHY DID KENTUCKY POWER STOP SELLING ITS ACCOUNTS RECEIVABLE?

A. The Company stopped selling its accounts in February 2022 in anticipation of the proposed sale to Liberty.

Q. WILL KENTUCKY POWER RESUME THE SALE OF ITS ACCOUNTS RECEIVABLE?

A. Yes. After the announced termination of the sale of Kentucky Power, the Company began the process of resuming the sale of its receivables. Kentucky Power presently expects accounts receivable financing to resume in mid-July 2023. The Company did not make any post-test year adjustments to cash working capital or factoring expense. The time required to resume the sale of receivables and the deadline to prepare and file this case, relative to the April 17, 2023 announcement of the termination of the proposed sale to Liberty, did not provide sufficient time to prepare such adjustments.

XII. DEPRECIATION STUDIES

Q. IS THE COMPANY PROPOSING TO UPDATE DEPRECIATION EXPENSE?

A. No, as part of the Company's effort to both manage and offset the Company's requests in this proceeding, the Company is not proposing to update depreciation expense in this case. Therefore, the Company did not perform an updated depreciation study as part of this case.

Q. WHERE CAN COPIES OF THE COMPANY'S MOST RECENT DEPRECIATION STUDIES BE FOUND?

A. Current Big Sandy depreciation rates were reviewed and approved as a part of a settlement in Case No. 2017-00179. A summary of the Company's most recent depreciation study and a copy of the study itself for Steam Production (Big Sandy Unit 1) were included in the Direct Testimony and exhibits of Company Witness Cash in Case No. 2017-00179.[13]

Transmission, Distribution and General Plant depreciation rates were last reviewed in Case No. 2014-00396 as part of a depreciation study filed in that case. Current depreciation rates for Transmission and General Plant were approved to be updated as part of a settlement in Case No. 2014-00396. Distribution depreciation rates remained

[13] See Direct Testimony of Jason A. Cash and Exhibit JAC-1, In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief, Case No. 2017-00179 (June 28, 2017).

unchanged as a result of the order issued in Case No. 2014-00396. Current depreciation rates for Distribution Plant are based on a depreciation study filed in Case No. 91-066.

A summary of the Company's most recent depreciation study and a copy of the study itself for Transmission, Distribution and General were included in the Direct Testimony and exhibits of Company Witness Davis in Case No. 2014-00396.[14]

Current Mitchell depreciation rates were approved to be updated as part of the settlement in Case No. 2017-00179. The last depreciation study performed for the Mitchell Plant was filed in Case No. 2014-00396, noted above.

XIII. AMORTIZATION PERIODS FOR CERTAIN OTHER DEFERRALS

Q. OVER WHAT PERIOD IS THE COMPANY SEEKING TO RECOVER THE REGULATORY ASSETS ADDRESSED BY COMPANY WITNESS WHITNEY?

A. The Company is proposing to amortize over the periods indicated the following regulatory assets:

- Big Sandy Unit 1 Operations Rider Regulatory Asset – 3 years
- NERC Compliance and Cybersecurity Cost Deferral Asset – 5 years
- Plant Maintenance Cost Deferral Liability – 3 years

The requested amortization periods are also supported by Company Witness Whitney and are consistent with previously approved amortization periods for these assets and liabilities.

[14] See Direct Testimony of David A. Davis and Exhibit DAD-2, In The Matter Of: Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief, Case No. 2014-00396 (December 23, 2014).

XIV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Brian K. West

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, on June 26, 2023.

Scott E. Bishop
Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

STEVEN M. FETTER

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
STEVEN M. FETTER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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STEVEN M. FETTER
ON BEHALF OF
KENTUCKY POWER COMPANY

CASE NO. 2023-00159

I. INTRODUCTION, BACKGROUND, AND KEY POINTS

Q. Please state your name, position, and business address.

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is 1240 West Sims Way, Port Townsend, Washington 98368.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Kentucky Power Company ("Kentucky Power" or "the Company") before the Kentucky Public Service Commission ("Commission" or "KPSC").

Q. By whom are you employed and in what capacity?

A. I am President of Regulation UnFettered, a utility advisory firm that I started in April 2002. Prior to that, I was employed by Fitch, Inc. ("Fitch"), a credit rating agency based in New York and London. Prior to that, I served as Chairman of the Michigan Public Service Commission ("Michigan PSC"). I am also an attorney, having graduated from the University of Michigan Law School in 1979.

Q. Please describe your service on the Michigan PSC.

A. I was appointed as a Commissioner to the three-member Michigan PSC in October 1987. In January 1991, I was promoted to Chairman and retained that designation following reappointment in 1993. During my tenure as Chairman, timeliness of commission processes was a major focus, and my colleagues and I achieved the goal of eliminating the agency's case backlog for the first time in 23 years. While on the Michigan PSC, I also served as Chairman of the Board of the National Regulatory Research Institute ("NRRI"), the research arm of the National

Association of Regulatory Utility Commissioners ("NARUC"). After leaving regulatory service, I was appointed to the NRRI Board as a public member. I have also served as a lecturer at Michigan State University's Institute of Public Utilities Annual Regulatory Studies Program ("Camp NARUC") and at NARUC's New Commissioner Regulatory Orientation.

Q. Please describe your role as President of Regulation UnFettered.

A. I formed a utility advisory firm to use my financial, regulatory, legislative, and legal expertise to aid the deliberations of regulators, legislative bodies, and the courts, and to assist them in evaluating regulatory issues. My clients have included investor-owned and municipal electric, natural gas and water utilities, state public utility commissions and consumer advocates, non-utility energy suppliers, international financial services and consulting firms, and investors.

Q. Please describe your role during your employment with Fitch.

A. I was Group Head and Managing Director of the Global Power Group within Fitch. In that role, I served as group manager of the combined 18-person New York and Chicago utility team. I was originally hired to interpret the impact of regulatory and legislative developments on utility credit ratings, a responsibility I continued to have throughout my tenure at the rating agency. In April 2002, I left Fitch to start Regulation UnFettered.

Q. How long were you employed by Fitch?

A. I was employed by Fitch from October 1993 until April 2002. In addition, Fitch retained me as a consultant for a period of approximately six months after I left the agency.

Q. How does your experience relate to your testimony in this proceeding?

A. My experience as Chairman and Commissioner on the Michigan PSC and my subsequent professional experience with financial analysis and ratings of the U.S. electric and natural gas sectors – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of a regulator's role vis-à-vis regulated utilities, both in setting their rates as well as the appropriate terms and conditions for the service they provide. In addition, for the past 22 years I have been a member of the Wall Street Utility Group, an honorary society comprised of debt and equity analysts assigned to cover and make assessments of companies within the utility sector.

Q. Have you previously given testimony before regulatory and legislative bodies?

A. Yes. Since 1990, I have testified before the U.S. Senate, the U.S. House of Representatives, the Federal Energy Regulatory Commission, federal district and bankruptcy courts, and various state and provincial legislative, judicial, and regulatory bodies in more than 100 proceedings or hearings on the subjects of credit risk and cost of capital within the utility sector, utility regulatory and legislative policies, electric and natural gas utility restructuring, fuel and other energy cost adjustment mechanisms, regulated utility mergers and acquisitions, construction work in progress and other interim rate recovery structures, utility securitization bonds, and nuclear energy. I have previously testified and been accepted as an expert witness before this Commission in the 2005 merger proceeding involving Cinergy/Cincinnati Gas & Electric Company and Union Light, Heat and Power Company – Duke Energy Corporation in Docket No. 2005-00228. My full educational and professional background is presented in my Appendix - 1.

Q. What is the purpose of your direct testimony?

A. Utilizing my past experience as a state utility commission Chairman and head of a major utility credit rating practice, my direct testimony focuses on the rate-setting process and the "regulatory compact"; the importance of credit ratings for regulated utilities and their customers; the importance of constructive utility regulation as an underpinning of strong credit quality; how the Company is currently viewed by the credit rating agencies; and how the financial community currently views the utility regulatory environment within Kentucky.

Q. Please highlight the key points you wish to emphasize in this case.

A. The core concept of utility rate-setting is to provide for a fair rate of return on investment and recovery of prudently-incurred costs. Meeting these goals within what has been called the "regulatory compact" provides a regulated utility with the financial integrity needed to maintain reliable utility infrastructure. Such strength is exhibited to the financial community through strong credit ratings. Accordingly, a utility's credit ratings are central to its ability to raise capital at reasonable cost and upon reasonable terms.

Regulation is a key qualitative component of a utility's credit ratings, and Kentucky is viewed by the financial sector in the middle third of credit supportive states, which is a relatively neutral factor in the credit ratings assigned to the state's regulated utilities. Adrien M. McKenzie, the Company's Return on Equity ("ROE") witness, explains in detail the appropriate ROE level and capital structure for Kentucky Power under its current circumstances. As noted in the testimony of Kentucky Power President and COO Cynthia G. Wiseman, notwithstanding Witness McKenzie's expert opinion as to the appropriate ROE level, the Company has determined that the more appropriate strategy is to seek a lower authorized ROE of 9.9%, owing to the difficult economic and financial challenges currently facing the customers in the utility's service territory.

Kentucky Power currently holds the following corporate credit ratings from the three major rating agencies: Moody's Investors Service ("Moody's"), 'Baa3' with a Stable outlook; Standard & Poor's ("S&P"), 'BBB' with a Stable outlook; and Fitch, similarly at 'BBB', with a Stable outlook. These ratings are weak for a regulated utility, with Moody's rating just above the investment-grade/non-investment-grade dividing line. For Kentucky Power to be able to improve its credit ratings toward the 'BBB+' / 'Baa1' rating level that I have long testified represents the lowest appropriate credit rating level for a U.S. regulated utility, I encourage the Commission to set the ROE and capital structure at levels no lower than the alternative reduced level proposed by the Company. Such a Commission determination would represent regulatory support that should be sufficient to avoid further weakening of the Company's credit profile, and could allow the Company to improve its credit profile over time. On the other hand, a less than constructive decision by the Commission in this case could lead to further negative credit rating actions, potentially moving the Company into below investment-grade territory. Such junk bond status would increase the Company's costs for capital, including its normal day-to-day capital investment for reliability during a time of increasing inflationary pressure, ultimately leading to higher rates for customers.

Q. With your 20+ year history participating in utility rate cases, could you offer thoughts on the Company's decision to seek an authorized ROE lower than as recommended by its ROE witness?

A. Yes. During that period, I have participated in more than 100 regulatory proceedings, the majority of which involved ROE issues – and I note that I have not always been testifying on the utility side. I cannot remember a utility voluntarily breaking away from its ROE witness in a downward direction at the time that direct testimony was filed. So I view Kentucky Power's step on behalf of its customers to be significant.

Q. With ROE being a crucial issue in this case, can you offer further background on the subject?

A. Yes. It is important to state that neither a commission nor a regulated utility sets the prevailing ROE. In my experience, a commission's role is to consider expert input from all parties and set rates based upon an ROE that it believes will be sufficient to allow the utility to recover the costs it will have to pay to attract equity capital. Thereafter, it is the capital markets that set the actual investor expected

ROE. Thus, if rates are set too low to meet that cost, the utility will have to pay what the market demands, and its costs will not be fully recovered.

Q. Looking to Kentucky Power's situation is this case – Company Witness Wiseman points to recent annual earned ROE of 2.88% and a failure to earn full authorized ROE for over five years. How do you view the Company's financial position as it relates to financial integrity and overall operations?

A. First off, let me take Kentucky Power's **actual ROE data** discussed by Company Witness Wiseman: *during the past four years, below 8.0% and down to 2.88%,* and compare it to U.S. investor-owned electric utility **awarded ROE data** during that same period: *2022 – 9.47%; 2021 – 9.40%; 2020 – 9.43%; 2019 – 9.64%.*[1]

ROEs at Kentucky Power's diminished levels during the recent past are untenable going forward. Although I expect that the Company will continue to run its system at a safe level, from my experience as Chairman of the Michigan Commission, I believe serious financial weakness can only lead to one thing: diminished reliability to the detriment of customers. In addition, that financial weakness would be exacerbated if Kentucky Power's credit ratings were to be further downgraded, increasing its financing costs, as well as limiting access to certain segments of investors. As I will explain, those ratings need to go in the opposite direction, moving upward rather than down.

Q. How would you sum up the views of institutional investors considering providing funding to Kentucky Power?

A. Investors expect that rates will be set at a level that allows the authorized ROE to be achieved by an efficiently-run utility, along with full recovery of prudent expenditures in the operation of the company. To the extent that those aims are not fulfilled, concerns would arise across the financial community, from the equity side through to the debt side. Based upon my long experience as a regulator, bond rater and now consultant to a wide range of utility stakeholders, I believe that customers

[1] "EEI 2022 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry."

benefit when their utility is regulated in a consistent manner, where the utility can attract capital, provide fair returns, and operate with high reliability. That happens when rates align with the true cost of efficient operations. Accordingly, I encourage the Commission to set an authorized ROE, supported by appropriate ratemaking, that would allow the Company, assuming prudent operations on its part, to strengthen its financial profile and, over time, improve its credit ratings. These are the combined regulatory and utility operational steps that will lead to lower costs and sustained operational reliability for the benefit of customers.

II. RATE-SETTING AND PRUDENCY IN THE ELECTRIC UTILITY INDUSTRY

Q. Could you provide a brief review of the rate-setting process for electric utilities?

A. Yes. Electric utilities, in order to fund their operations and ongoing capital investment, need rates set that are sufficient to cover their costs. U.S. investor-owned electric utilities are subject to administrative price setting by the relevant state and federal regulatory authorities. Those regulators typically employ "cost of service" rate-making. Under this method of pricing, the regulator determines a "revenue requirement" that is used to structure rates to allow the utility to recover all of its prudently-incurred costs. For investor-owned utilities like Kentucky Power, such rates are set by the economic regulators to allow the utility to earn a "reasonable rate of return" (i.e., the cost required to attract needed equity investment).

Q. Could you discuss the legal framework of the rate-setting process?

A. Yes. The core principle that underlies rate-setting at both the federal and state levels is the attainment of "just and reasonable" rates that are fair to both the utility (and its investors) and also its customers. The constitutional basis for this standard goes back many years to two seminal U.S. Supreme Court cases which explained this fairness concept. First, regulated utilities should have a reasonable opportunity to receive recovery of their prudently-incurred costs, a principle set forth in *Federal*

Power Commission v. Hope Natural Gas Co., ("*Hope*"), 320 U.S. 591 (1944), which held that "the result reached and not the method employed" is controlling in determining "just and reasonable" rates. In addition, the ability of a regulated utility to earn a fair return on its invested capital had earlier been ensured by the U.S. Supreme Court in *Bluefield Water Works and Improvement Co. v. Public Service Commission* ("*Bluefield*"), 262 U.S. 679, 692 (1923), which required rates "sufficient to yield a reasonable return on the value of the property to be used, at the time it is being used to render the service." Regarding the utility's ongoing financial integrity, *Bluefield* held that the return should be "sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise money for the proper discharge of its public duties." Similarly, *Hope* requires that the return "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." The legal structure laid out by *Hope* and *Bluefield* endures to this day and guides the decision-making activities of the regulators at both the state and federal levels, as well as the courts when they are called upon to review and opine upon the legality of the determinations made by the various utility regulatory bodies.

Q. You mention the concept of prudency within your discussion of the rate-setting process. How does prudency fit within regulatory review of utility investment?

A. The concept of "prudency" is present in the legislative and administrative rules of every utility commission across the U.S. In their reference book *Fundamentals of Energy Regulation*, authors (and Ph.D. economists) Lesser & Giacchino discuss prudence both in terms of the deference accorded utility management decisions, as well as the review process before imprudent behavior is found to have occurred:

> "…utility management is given the benefit of the doubt, and management's decisions are presumed reasonable unless the facts show otherwise. …Moreover, the prudence of managerial decisions must be judged on their reasonableness at the time those decisions were made and based on information then available. Prudence is not meant as an

> exercise in hindsight regulation. In essence, a prudent decision is one that a reasonable person could have made in good faith, given the information and decision tools available at the time of the decision."[2]

In support of that position, economist Charles F. Phillips in his widely-respected public utility regulation treatise *The Regulation of Public Utilities* quotes the views of the Massachusetts and New York commissions:

> "A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] merely to substitute its best judgment for the judgments made by the company's managers." [*In re Western Mass. Elec. Co.*, 80 PUR4th at 501.]

> "The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company." [*In re Consolidated Edison Co. of N.Y. Inc.*, Opinion No. 79-1 (N.Y. 1979), 5-6.] [3]

Q. Other aspects of utility regulation that you have often testified about are the "Regulatory Compact" and "Constructive Utility Regulation". Could you provide a description of what these key concepts entail?

A. There is an unwritten but core concept within the regulatory process known as the "regulatory compact." Since there is no hard and fast universal rule or regulation delineating the "regulatory compact," it has been described in many different ways. In the above-noted reference book, Lesser & Giacchino describe that under the "regulatory compact:"

> … the regulator grants the company a protected monopoly, essentially a franchise, for the sale and distribution of electricity or natural gas to customers in its defined service territory. In return, the company commits

[2] Jonathan A. Lesser & Leonardo R. Giacchino, *Fundamentals of Energy Regulation*, 42 (1st Ed. 2007).
[3] Phillips, *The Regulation of Public Utilities*, 340-341.

> to supply the full quantities demanded by those customers at a price calculated to cover all operating costs plus a "reasonable" return on the capital invested in the enterprise. The first half of this "compact" protects the company from would-be competitors and secures for the public the substantial economies of scale available in the large-scale production of electricity. The second half of the "compact" counteracts the injurious tendency of monopolies to raise prices above the level that would prevail in a competitive market.[4]

In my experience advising a range of utility industry stakeholders across the U.S., I have found that every utility commission adheres to some conception of the "regulatory compact" in concert with the constitutionally-and-statutorily-mandated prudency standards.

In addition, my own conception of "constructive utility regulation" is that which aligns the seemingly competitive interests of utility investors and utility customers in a manner that is consistent and steady over time, so that all parties have reasonable expectations about how regulatory policy will be effectuated. Importantly, it supports a utility's ability to provide safe and clean utility service to its customers with a high level of reliability at reasonable rates. Constructive regulation is efficient and predictable with a long-term focus on relatively stable rates, while also recognizing the need for timely recovery of costs and the value to customers of a financially-strong utility with ready access to the capital markets at attractive rates, even when the financial markets are under stress. It recognizes that utility investors react negatively to major, frequent or sudden changes in regulatory policy and that such uncertainty ultimately has an adverse effect on customers. In sum, longstanding constructive regulatory policy should provide a utility with the confidence to make capital-intensive investments and incur O&M expenses for the benefit of its customers, with the reasonable expectation that those costs would be recovered in a timely manner, including a fair return on investment, consistent with that stable and consistent regulatory policy.

[4] Lesser & Giacchino, *Fundamentals of Energy Regulation*, 43-44.

Q. In your earlier legal discussion of *Hope* and *Bluefield*, you reference regulated utilities being able to maintain their credit strength. With your credit ratings leadership role at Fitch, can you discuss the importance of "Constructive Regulation" in the rating agencies' assessment of utility credit profiles?

A. Yes, I saw firsthand how important constructive regulation is to agencies when Fitch recruited me to provide regulatory analysis after I had decided to move on from the Michigan PSC. Moody's has highlighted the critical role that regulators play in a June 23, 2017 report entitled "Rating Methodology: Regulated Electric and Gas Utilities:"

> An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer … can lead to a more politically charged rate-setting environment. …Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.[5]

And S&P has long held the same view:

> Regulatory advantage is the most heavily weighted factor in [S&P's] analysis of a regulated utility's business risk profile. …An established, dependable approach to regulating utilities is a hallmark of a credit-supportive jurisdiction. …Major or frequent changes to the regulatory model invariably raise risk due to the possibility of future changes. Steady application of transparent, comprehensible policies and practices lowers risk. …We adjust the assessment downward if the development of the framework was contentious due to policy disputes or legal actions, indicating that the political consensus regarding utility regulation is fragile. … [A] regulatory approach that allows utilities the opportunity to consistently earn a reasonable return as a positive credit factor in our regulatory assessments. …We measure the timeliness of rate decisions, the obsolescence of the costs on which the rates are based, the timing of interim rates, and other practices (such as allowing rates to automatically change in a future period based on inflation) that affect a utility's ability to earn its authorized return. …Practices such as legislative or regulatory recognition of the need for preapproval of [large capital projects], periodic reviews that

[5] Moody's Research: "Rating Methodology: Regulated Electric and Gas Utilities," June 23, 2017.

> substantively involve the regulator in the progress of the project, and rolling prudence determinations during construction can reduce the general level of risk…[W]e consider financial stability to be of substantial importance [with cash taking] precedence in credit analysis. …We assess a jurisdiction most strongly if all large expense items are recoverable through an automatic tariff clause that is based on projected costs, adjusts frequently, and has no record of any significant disallowances. … [A] primary factor … is the political independence of regulators.[6]

III. CREDIT RATINGS AND THEIR IMPORTANCE TO REGULATED UTILITIES

Q. What is a credit rating and why is it important?

A. A credit rating reflects an independent judgment of the general creditworthiness of an obligor or of a specific debt instrument. While credit ratings are important to both debt and equity investors for a variety of reasons, their most important purpose is to communicate to investors the financial strength of a company or the underlying credit quality of a particular debt security issued by that company.

Credit rating determinations are made by credit rating agencies through a committee process involving individuals with knowledge of a company, its industry, and its regulatory environment. Corporate rating designations of S&P and Fitch have 'AAA', 'AA', 'A' and 'BBB' category ratings within the investment-grade ratings sphere, with 'BBB-' as the lowest investment-grade rating and 'BB+' as the highest non-investment-grade rating. Comparable rating designations of Moody's at the investment-grade dividing line are 'Baa3' and 'Ba1', respectively. In addition, the agencies seek to make their rating judgments even more precise by dividing each of the rating categories into three levels ("+", "neutral", and "-" at S&P and Fitch, and 1, 2 & 3 at Moody's). The following chart illustrates the comparability of ratings among the three agencies.

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[6] S&P Research: "Assessing U.S. Investor-Owned Utility Regulatory Environments," January 7, 2014.

Ratings Categories – Comparability Between Agencies

Investment Grade	
S&P and Fitch	Moody's
AAA	Aaa
AA+	Aa1
AA	Aa2
AA-	Aa3
A+	A1
A	A2
A-	A3
BBB+	Baa1
BBB ([7])	Baa2
BBB-	Baa3 ([8])

Below Investment Grade	
S&P and Fitch	Moody's
BB+	Ba1
BB	Ba2
BB-	Ba3
B+	B1
B	B2
B-	B3
CCC	Caa
CC	Ca
C	C
D	[C]

Corporate credit rating analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income debt issuers. A credit rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. At times, a credit rating also incorporates some consideration of ultimate recovery of investment in case of default or insolvency. Ratings can also be used by contractual counterparties to gauge both the short-term and longer-term financial health and viability of a company, including decisions related to required collateral levels, with higher-rated entities facing lower requirements.

Q. How would you describe Kentucky Power's credit ratings status?

A. Kentucky Power's corporate issuer credit ratings show some significant weakness within the 'BBB' / 'Baa' category.[9] I have long testified that a regulated utility should aim to hold ratings no lower than 'BBB+' / 'Baa1', with a longer-term goal

[7] Kentucky Power corporate credit ratings from S&P and Fitch, each with a Stable outlook.
[8] Kentucky Power corporate credit rating from Moody's with a Stable outlook.
[9] Corporate or issuer utility credit ratings reflect the intrinsic financial strength of the utility being rated, with no backing from or recourse against specific utility assets. At times, regulated utilities issue secured debt, representing utility borrowings that are backed by collateral, usually in the form of utility real property. In almost all instances, secured credit ratings are higher than corporate/issuer credit ratings because, in the case of a utility defaulting on its bond payment obligations, secured debtholders have recovery priority on the defined collateral as compared to the claims of unsecured debtholders.

of moving into (or maintaining in) the 'A' category. Accordingly, all three of Kentucky Power's corporate ratings now rest below my recommended scale, with the Moody's rating just above the investment grade / non-investment grade dividing line, which increases the importance of this rate proceeding.

Q. Can you share how you came to your opinion that 'BBB+' / 'Baa1' is the appropriate minimum level rating level for a regulated utility?

A. Yes. I set the lower end of my recommendation at 'BBB+' during the 1990's, back when I was serving as head of the utility ratings practice at Fitch. I did so because I believed that that level provided a regulated utility with substantial protection related to financing in the case of a major downturn in the economy or unrest in the capital markets. Thereafter, we all witnessed two regulated utilities that faced unforeseen, unavoidable, and virtually unimaginable catastrophic events – the September 11 terrorist attack in New York City, and Hurricane Katrina in New Orleans. Those horrific events led me to add the longer-term goal of achieving or maintaining ratings in the 'A' category, a level at which I cannot imagine that funding would ever be restricted in the face of severe financial or operational duress.

Q. Please explain your reasoning.

A. On September 11, 2001, Consolidated Edison of New York ("Con Ed") held two 'A' category ratings. In the face of the terrible events of that day, Con Ed was able immediately to initiate one of the largest infrastructure recovery efforts any industry has ever faced, without seeking special treatment from lenders or suppliers. I contrast that with Entergy New Orleans ("ENO"), whose credit profile had been on an improving track from 'BBB' with a Credit Watch Negative to a 'BBB' with a Stable outlook. Then in August 2005, Hurricane Katrina devastated the utility's infrastructure and customer base. Amidst that tragedy, the utility faced resistance from its contractual counterparties to provide supplies and assistance. ENO soon filed for bankruptcy, paving the way for parent Entergy Corporation to provide $200 million in funds to support commencement of the long process of reorganization and recovery. I acknowledge that, in this case, my recommendations do not target the longer-term goal of 'A'-category ratings for Kentucky Power. Rather, first things first: my position supports allowing the Company's ratings to move upward away from the precipice of junk bond status on the way to eventually holding 'BBB+ / Baa1' ratings from all three of the agencies.

Q. With your close focus on credit rating levels, could you explain the importance of a regulated utility's credit strength for both customers and investors?

A. A utility's credit profile has a significant impact on its ability to raise capital on a timely basis and upon reasonable terms. As economist Charles F. Phillips states in his treatise on utility regulation:

> Bond ratings are important for at least four reasons: (1) they are used by investors in determining the quality of debt investment; (2) they are used in determining the breadth of the market, since some large institutional investors are prohibited from investing in the lower grades; (3) <u>they determine, in part, the cost of new debt, since both the interest charges on new debt and the degree of difficulty in marketing new issues tend to rise as the rating decreases</u>; and (4) they have an indirect bearing on the status of a utility's stock and on its acceptance in the market.[10]

Thus, a utility with strong credit ratings is not only able to access the capital markets on a timely basis at reasonable rates, it is also able to pass the benefit from those attractive interest rate levels on to customers since cost of capital gets factored into utility rates. Conversely, but of equal importance, the lower a utility's credit rating, the more the utility must pay to raise funds from debt and equity investors to carry out its capital-intensive operations, and those higher capital costs get factored into the rates that consumers are required to pay. Significantly, a regulated utility is required to attract funding from investors even if the markets are in turmoil and costs are escalating wildly. Strong credit ratings limit the negative effects of having to finance at times of great volatility within the capital markets.

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[10] Phillips, Charles F., Jr., <u>The Regulation of Public Utilities</u>, Arlington, Virginia: Public Utilities Reports, Inc., 1993, at p. 250 (emphasis supplied). *See also* Public Utilities Reports Guide: "Finance," Public Utilities Reports, Inc., 2004 at pp. 6-7 ("Generally, the higher the rating of the bond, the better the access to capital markets and the lower the interest to be paid.").

Q. What qualitative factors are used by the rating agencies to establish utility credit ratings?

A. The most important qualitative factors are regulation, management and business strategy, and access to energy, gas, and fuel supply with recovery of associated costs.

Q. What are the key quantitative measures?

A. The major rating agencies use several financial measures within their utility financial analysis. S&P has been the most transparent of the rating agencies and currently highlights the following two core financial ratios as its key indicators: Funds from Operations to Debt (FFO / Debt), which focuses on cash flow; and Debt to Earnings Before Interest, Taxes, Depreciation and Amortization (Debt / EBITDA), which provides a comparative profitability measure.[11] A focus on these two ratios is consistent with S&P's long-held belief that "Cash flow analysis is the single most critical aspect of all credit rating decisions,"[12] an opinion shared by both Moody's and Fitch. I note that all three agencies often adjust these key ratios to reflect imputed debt and interest-like fixed charges related to operating leases and certain other off-balance sheet obligations.

Q. Why is regulation a key qualitative component of the utility credit rating process?

A. Regulation is a key factor in assessing the financial strength of a utility because a state public utility commission determines revenue levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service that affect a utility's cost of service. As Moody's has long noted, "A utility's ability to recover its costs

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[11] S&P Research: "Corporate Methodology," November 19, 2013 (republished on April 1, 2019 with revisions and nonmaterial changes unrelated to references to that report in this testimony).

[12] S&P Research: "A Closer Look at Ratings Methodology," November 13, 2006.

and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings."[13]

IV. FINANCIAL COMMUNITY PERCEPTIONS OF THE KPSC

Q. How is the Kentucky Commission viewed by the financial community?

A. Relatively neutral when considered among all state regulators across the US. Probably the most objective and respected commentator on regulatory policy and activities from a financial community perspective is Regulatory Research Associates ("RRA"). RRA currently rates the Kentucky regulatory environment (which goes beyond the Commission to also include legislative and executive branch policies) as Average 2, placing Kentucky in the middle third of the 53 regulatory jurisdictions upon which RRA currently opines. RRA noted on February 1, 2023 that:

> Historically, Kentucky regulation was somewhat more constructive than average from an investor perspective. Rate cases were typically resolved via settlements, and authorized equity returns … generally approximated prevailing nationwide industry averages at the time established. …However, on March 3, 2022, RRA lowered the ranking of Kentucky regulation to Average/2 … to account for the PSC's recent pattern of modifying rate case settlements [relating to stipulated ROEs and other minor adjustments]. The composition of the commission has changed meaningfully over the past year, and it is unclear whether [those] actions taken by the PSC … are indicative of a sustained move toward a more restrictive regulatory climate.

Accordingly, at present, Kentucky regulation is treated as a relatively neutral factor within the context of credit rating analysis.

Q. Does Moody's share this relatively neutral assessment about Kentucky regulation?

A. I would say 'Yes.' Prior to the proposed sale of Kentucky Power, Moody's described the Company's relationship with the Kentucky Commission as

[13] Moody's Research: "Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality: Evaluating a Utility's Ability to Recover Costs and Earn Returns," June 18, 2010.

"reasonable."[14] But not unlike the future regulatory uncertainty highlighted by RRA, Moody's recently noted that "The outcome of Kentucky Power's next rate case will help inform our view of the state of AEP's regulatory relationship with the KPSC following the sale termination."[15]

Q. How does S&P view the Kentucky regulatory environment?

A. Similarly. A couple of years ago, S&P stated, "Our business risk assessment reflects the regulatory support [the Company] receives in Kentucky."[16] Recently, however, post-termination of the sale, S&P has been clearer on what it will take to avoid a downgrade for Kentucky Power: "Going forward, we expect a modest improvement to stand-alone financial measures, reflecting rate case increases and a potential securitization, pending legislative and regulatory approvals."[17]

Q. And Fitch's assessment?

A. Fitch is currently more definitive, stating that Kentucky regulation is "generally constructive," and highlighting the beneficial nature of the presence of several cost recovery mechanisms, including fuel, purchased power, environmental compliance, and infrastructure replacement clauses that mitigate the negative effects of regulatory lag.[18]

V. CONCLUSION

Q. Do you have concluding thoughts?

A. Yes. For the reasons I have discussed, I strongly believe that utilities and their regulators should strive to attain corporate credit ratings no lower than 'BBB+ / Baa1'. Accordingly, I encourage the Commission to reduce any uncertainty as to

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[14] Moody's Research: "Kentucky Power Company Update to Credit Analysis," June 29, 2022.
[15] Moody's Research: "American Electric Power Company, Inc., Termination of Kentucky operations sale has no immediate credit impact," April 18, 2023.
[16] S&P Research: "Kentucky Power Co. CreditWatch Implications Revised to Negative From Developing on AEP Sale Agreement," October 28, 2021.
[17] S&P Research: "American Electric Power Ratings Affirmed; Kentucky Power Downgraded to 'BBB' on Weaker Financials; Outlook Stable," April 20, 2023.
[18] Fitch Research: Fitch Affirms AEP and Subsidiaries; Outlook Stable," February 28, 2023.

this body's future regulatory direction that may exist by providing an ongoing constructive regulatory environment that respects the interests of all stakeholders within the regulatory process, including the consumers that pay the bills and the investors that fund the Company's operations. Such positive regulation, coupled with strong utility operational performance, should allow the Company to strengthen its credit profile over time toward the minimum rating level I recommend.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Education **University of Michigan Law School, J.D. 1979**

Bar Memberships: U.S. Supreme Court, New York, Michigan
University of Michigan, A.B. Media (Communications) 1974

April 2002 – Present

President - Regulation UnFettered- Port Townsend, Washington

Founder of advisory firm providing regulatory, legislative, financial, legal, and strategic planning advisory services for the energy, water, and telecommunications sectors, including public utility commissions and consumer advocates; federal and state testimony; credit rating advisory services; negotiation, arbitration, and mediation services; skills training in ethics, negotiation, and management efficiency.

Service on Boards of Directors of: Central Hudson (Fortis Inc. subsidiary) (Chairman, Governance and Human Resources Committee); and Previously CH Energy Group (Lead Independent Director; Chairman, Audit Committee, Compensation Committee, and Governance and Nominating Committee); National Regulatory Research Institute (Chairman); Keystone Energy Board; and Regulatory Information Technology Consortium; Member, Wall Street Utility Group; Participant, Keystone Center Dialogues on RTOs and on Financial Trading and Energy Markets.

October 1993 – April 2002

Group Head and Managing Director; Senior Director -- Global Power Group, Fitch IBCA Duff & Phelps -- New York / Chicago

Manager of 18-employee ($15 million revenue) group responsible for credit research and rating of fixed income securities of U.S. and foreign electric and natural gas companies and project finance; Member, Fitch Utility Securitization Team.

Led an effort to restructure the global power group that in three years' time resulted in 75% new personnel and over 100% increase in revenues, transforming a group operating at a substantial deficit into a team-oriented profit center through a combination of revenue growth and expense reduction.

Achieved national recognition as a speaker and commentator evaluating the effects of regulatory developments on the financial condition of the utility sector and individual companies; Cited by Institutional Investor (9/97) as one of top utility analysts at rating agencies; Frequently quoted in national newspapers and trade publications including The New York Times, The Wall Street Journal, International Herald Tribune, Los Angeles Times, Atlanta Journal-Constitution, Forbes and Energy Daily; Featured speaker at conferences sponsored by Edison Electric Institute, Nuclear Energy

Institute, American Gas Assn., Natural Gas Supply Assn., National Assn. of Regulatory Utility Commissioners (NARUC), Canadian Electricity Assn.; Frequent invitations to testify before U.S. Senate (on C-Span) and House of Representatives, and state legislatures and utility commissions.

Participant, Keystone Center Dialogue on Regional Transmission Organizations; Member, International Advisory Council, Eisenhower Fellowships; Author, "A Rating Agency's Perspective on Regulatory Reform," book chapter published by Public Utilities Reports, Summer 1995; Advisory Committee, Public Utilities Fortnightly.

March 1994 – April 2002

Consultant -- NYNEX -- New York, Ameritech -- Chicago, Weatherwise USA -- Pittsburgh

Provided testimony before the Federal Communications Commission and state public utility commissions; Formulated and taught specialized ethics and negotiation skills training program for employees in positions of a sensitive nature due to responsibilities involving interface with government officials, marketing, sales or purchasing; Developed amendments to NYNEX Code of Business Conduct.

October 1987 - October 1993

Chairman; Commissioner -- Michigan Public Service Commission -- Lansing

Administrator of $15-million agency responsible for regulating Michigan's public utilities, telecommunications services, and intrastate trucking, and establishing an effective state energy policy; Appointed by Democratic Governor James Blanchard; Promoted to Chairman by Republican Governor John Engler (1991) and reappointed (1993).

Initiated case-handling guideline that eliminated agency backlog for first time in 23 years while reorganizing to downsize agency from 240 employees to 205 and eliminate top tier of management; MPSC received national recognition for fashioning incentive plans in all regulated industries based on performance, service quality, and infrastructure improvement.

Closely involved in formulation and passage of regulatory reform law (Michigan Telecommunications Act of 1991) that has served as a model for other states; rejuvenated dormant twelve-year effort and successfully lobbied the Michigan Legislature to exempt the Commission from the Open Meetings Act, a controversial step that shifted power from the career staff to the three commissioners.

Elected Chairman of the Board of the National Regulatory Research Institute (at Ohio State University); Adjunct Professor of Legislation, American University's Washington College of Law and Thomas M. Cooley Law School; Member of NARUC Executive, Gas, and International Relations Committees, Steering Committee of U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project, and Federal Energy Regulatory Commission Task Force on

Natural Gas Deliverability; Eisenhower Exchange Fellow to Japan and NARUC Fellow to the Kennedy School of Government; Ethics Lecturer for NARUC.

August 1985 - October 1987

Acting Associate Deputy Under Secretary of Labor; Executive Assistant to the Deputy Under Secretary -- U.S. Department of Labor -- Washington DC

Member of three-person management team directing the activities of 60-employee agency responsible for promoting use of labor-management cooperation programs. Supervised a legal team in a study of the effects of U.S. labor laws on labor-management cooperation that has received national recognition and been frequently cited in law reviews (U.S. Labor Law and the Future of Labor-Management Cooperation, w/S. Schlossberg, 1986).

January 1983 - August 1985

Senate Majority General Counsel; Chief Republican Counsel -- Michigan Senate -- Lansing

Legal Advisor to the Majority Republican Caucus and Secretary of the Senate; Created and directed 7-employee Office of Majority General Counsel; Counsel, Senate Rules and Ethics Committees; Appointed to the Michigan Criminal Justice Commission, Ann Arbor Human Rights Commission and Washtenaw County Consumer Mediation Committee.

March 1982 - January 1983

Assistant Legal Counsel -- Michigan Governor William Milliken -- Lansing

Legal and Labor Advisor (member of collective bargaining team); Director, Extradition and Clemency; Appointed to Michigan Supreme Court Sentencing Guidelines Committee, Prison Overcrowding Project, Coordination of Law Enforcement Services Task Force.

October 1979 - March 1982

Appellate Litigation Attorney -- National Labor Relations Board -- Washington DC

Other Significant Speeches and Publications

Filing for Bankruptcy Isn't the Right Solution for Puerto Rico (Forbes Online, November 2015)

The "A" Rating (Edison Electric Institute Perspectives, May/June 2009)

Perspective: Don't Fence Me Out (Public Utilities Fortnightly, October 2004)

Climate Change and the Electric Power Sector: What Role for the Global Financial Community (during Fourth Session of UN Framework Convention on Climate Change Conference of Parties, Buenos Aires, Argentina, November 3, 1998)(unpublished)

Regulation UnFettered: The Fray By the Bay, Revisited (National Regulatory Research Institute Quarterly Bulletin, December 1997)

The Feds Can Lead…By Getting Out of the Way (Public Utilities Fortnightly, June 1, 1996)

Ethical Considerations Within Utility Regulation, w/M. Cummins (National Regulatory Research Institute Quarterly Bulletin, December 1993)

Legal Challenges to Employee Participation Programs (American Bar Association, Atlanta, Georgia, August 1991) (unpublished)

Proprietary Information, Confidentiality, and Regulation's Continuing Information Needs: A State Commissioner's Perspective (Washington Legal Foundation, July 1990)

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regunf@gmail.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 23, 2023 12:06:05 -8:00 [83C01820BB0D] [161.235.221.106]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Steven M. Fetter, being duly sworn, deposes and says he is the President, of Regulation Unfettered, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Steven M Fetter
Signed on 2023/06/23 12:06:05 -8:00

Steven M. Fetter

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Steven M. Fetter, on ___June 23, 2023_______.

Signed on 2023/06/23 12:06:05 -8:00

Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025
Notary Stamp 2023/06/23 12:06:05 PST 83C01820BB0D

Notarial act performed by audio-visual communication

My Commission Expires ______06/21/2025___________

Notary ID Number ____KYNP31964________________

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

STEVI N. COBERN

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
STEVI N. COBERN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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DIRECT TESTIMONY OF
STEVI N. COBERN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Stevi N. Cobern and I am the Customer Services Supervisor for Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 1645 Winchester Ave., Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Regents Bachelor of Arts degree from Marshall University in Huntington, West Virginia in 2022. In 2002, I began working for American Electric Power ("AEP") in AEP's Customer Operations Center. In 2009, I joined Kentucky Power, working in various departments including meter revenue operations and forestry. I transitioned back to customer service in 2018 as Customer Services Coordinator. In May 2021, I accepted my current position as Customer Services Supervisor.

Q. WHAT ARE YOUR RESPONSIBILITIES AS CUSTOMER SERVICES SUPERVISOR?

A. I am responsible for managing Kentucky Power's customer service team, which includes customer service account representatives for each district within our service territory. My team ensures that proactive and individualized service is provided to our commercial, industrial, and residential customers. As the local customer service team, we interact daily with customers, review investigation orders, analyze accounts and verify information in the field as needed. While reviewing investigation orders or to address concerns for a customer, our customer service team frequently visit customers' homes. We speak one on one with the customer, obtain a meter reading and walk the premise as needed to address an issue. The customer service team also is the main point of contact for larger commercial and industrial customers by managing these accounts both proactively and as the lead for any special project or concerns. We also are responsible for the administration of Kentucky Power's Home Energy Assistance ("HEA") programs, including Home Energy Assistance in Reduced Temperatures ("HEART"), Donation HEART, and Temporary Heating Assistance in Winter ("THAW"). We also address customer inquiries from the Kentucky Public Service Commission, Office of the Attorney General, and Better Business Bureau ensuring that such inquiries are appropriately investigated and responded to in a timely fashion.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before this Commission in Case No. 2019-00366, which concerned the Commission's investigation of investor-owned utilities' HEA programs.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe the Company's proposals in this case to (1) increase its residential energy assistance ("REA") surcharge in order to provide home energy assistance to more of its customers in need, and (2) extend the deadline for bill payment to give customers more time to pay their bills. Additionally, I will describe Kentucky Power's customer service approach by highlighting the Company's focus on customers, including customer communications and community outreach efforts.

IV. THE COMPANY'S PROPOSAL TO INCREASE CUSTOMER HOME ENERGY ASSISTANCE BENEFITS

Q. DOES KENTUCKY POWER PROVIDE CUSTOMER BENEFITS THROUGH A HEA PROGRAM?

A. Yes. Kentucky Power offers the HEART and THAW HEA programs.

Q. PLEASE DESCRIBE THE HEART AND THAW PROGRAMS.

A. HEART is designed to assist low-income Kentucky Power residential customers with their electric bill during the winter months. Qualifying customers with electric heat receive $115 each month from January to April and customers with non-electric heat receive $58 each month for these same four months. THAW is designed to help customers who do not require the broader and more sustained help provided by HEART, but who nonetheless need assistance with their electric service because of a temporary situation. THAW provides participating customers with assistance up to $175 and is available on a first come, first served basis from January through April or until designated funds are depleted.

Community Action Kentucky ("CAK") administers both programs through local community action agencies ("CAA") throughout the Company's service territory. As the Commission recognized and favorably commented upon in Case No. 2019-00366, Kentucky Power maintains a strong relationship with Community Action Kentucky and CAK's local CAAs. Kentucky Power, CAK, and the CAAs meet throughout each year to discuss the programs and collaborate on improvements. Meetings are scheduled by Kentucky Power before each program year and include training for community action agency employees about the HEART and THAW programs. Following each program year, Kentucky Power schedules meetings with CAK and their community action agencies to collaborate about the program year. In these meetings, the program year is discussed, including any concerns about the programs or application process and suggestions for improvement. The most common suggestion made by community action agency employees is to provide additional funding that will enable the programs to assist more customers.

Q. HOW ARE THE HEART AND THAW PROGRAMS FUNDED?

A. The Residential Energy Assistance Tariff ("Tariff R.E.A.") collects a monthly $0.30 per meter surcharge from residential customers. HEART and THAW are funded through a combination of Tariff R.E.A. and a dollar-for-dollar Company match. HEART is funded with 75% of the HEA funds available for distribution, and THAW is funded with the remaining 25% of HEA funding.

Q. WHAT IS THE CURRENT LEVEL OF HEA PROGRAM FUNDING?

A. As shown in Figure SNC-1, for the 2022-2023 program year, there was $613,160.75 available for HEART and $204,877.28 available for THAW to distribute to eligible participants. This amount of funding supported a total of 1,133 electric heating customers and 396 non-electric heating customers to the HEART program. As the THAW program supports a maximum of $175 per customer, this level of funding supported a minimum of 1,171 customers. Accordingly, the HEART and THAW programs supported a total of at least 2,700 customers.

Figure SNC-1: Current Funding for 2022-2023 Program Year

	HEART 75%		THAW 25%	
Total REA Funds (Post 10% Admin Cap)	**$ 613,160.75**		**$ 204,877.28**	
	Electric Heat (85%)	Non-Electric Heat (15%)	N/A	
Funding Available	$ 521,187	$ 91,974	$ 204,877	
Payment Amount	$ 115	$ 58	$ 175	
Total Available Benefit Per Customer	$ 460	$ 232	$ 175	
Number of Customers Able to Receive Benefits	1,133	396	1,171	**2,700**

Q. WHAT HEA-RELATED CHANGE IS THE COMPANY PROPOSING IN THIS CASE?

A. To provide additional home energy assistance to low-income customers and customers in need, Kentucky Power proposes to increase the Tariff R.E.A. rate and corresponding Company match by $0.10 monthly ($1.20 annually), to $0.40 per residential meter per month. An increase in the Tariff R.E.A. funding level will allow a greater number of customers to receive benefits from these programs. No operational changes to the programs are required, and CAK will continue to administer each program in the manner in place today.

Q. IS THE CURRENT LEVEL OF HEART FUNDING SUFFICIENT TO HELP ALL ELIGIBLE CUSTOMERS WHO SEEK ASSISTANCE?

A. No. Illustrated above in Figure SNC 1, HEART supported 1,133 electric heating customers and 396 non-electric heating customers. For the 2022-2023 program year, CAA accepted applications from 6,800 customers who qualified to receive assistance from HEART.

Q. WHAT LEVEL OF INCREMENTAL HEART AND THAW BENEFITS DOES THE COMPANY EXPECT TO MAKE AVAILABLE TO CUSTOMERS BY INCREASING THE TARIFF R.E.A. SURCHARGE AND COMPANY MATCH?

A. By increasing the Tariff REA surcharge and corresponding Company match to $0.40, the Company anticipates that the HEART and THAW programs will be able to support an additional approximately 1,000 participants. Figure SNC-2 provides the change to funding and number of participants to the 2022-2023 program year had the surcharge been $0.40 in that program year.

Figure SNC-2: Proposed Funding Layered on 2022-2023 Program Year

	HEART 75%		THAW 25%	
Total REA Funds (Post 10% Admin Cap)	**$ 841,715.21**		**$ 281,072.10**	
	Electric Heat (85%)	Non-Electric Heat (15%)	N/A	
Funding Available	$ 715,458	$ 126,257	$ 281,072	
Payment Amount	$ 115	$ 58	$ 175	
Total Available Benefit Per Customer	$ 460	$ 232	$ 175	
Number of Customers Able to Receive Benefits	1,555	544	1,606	**3,705**

V. THE COMPANY'S PAYMENT DEADLINE EXTENSION PROPOSAL

Q. PLEASE EXPLAIN KENTUCKY POWER'S PROPOSAL REGARDING CUSTOMER BILL PAYMENT DEADLINES.

A. To make on-time bill payment easier for customers, Kentucky Power proposes to extend the number of days between the monthly billing date and bill due date from 15 days to 21 days. If approved, this change would be implemented on a bills-rendered basis beginning on the date the Company's new base rates are effective. Implementation of this on a bills-rendered basis ensures a smoother implementation of this change from an administrative standpoint.

Q. WHY IS THE COMPANY PROPOSING THIS CHANGE?

A. Extending the time for payment will allow customers additional time to make an on-time payment. This change will put Kentucky Power closer in line with other investor-owned electric companies in Kentucky, which provide 21 or 22 days for payment. This additional time also will benefit customers who participate in extended payment arrangements, in which the total account balance is deferred and billed over several months, by giving those customers additional time each month to fulfill their payment obligations under such arrangements and thereby hopefully limiting the customers' need to modify or enter into further payment arrangements. For non-residential customers, this change will also extend the time frame for payment before a late payment charge is assessed. Company Witness Adams included this information in the lead-lag study and the results of that study are reflected in the cash working capital adjustment sponsored by Company Witness Whitney.

VI. <u>KENTUCKY POWER'S CUSTOMER CARE FOCUS</u>

Q. WHAT OTHER PROPOSALS IS THE COMPANY PROPOSING IN THIS CASE TO BENEFIT LOW-INCOME CUSTOMERS?

A. First, Company Witness Vaughan discusses the Company's Solar Garden proposal that will benefit all customers. Further, there is a low-income benefit option which would provide 50 percent of the energy benefits to customers participating in the Federal Low Income Home Energy Assistance Program. These customers would receive a yearly bill credit in January, when customer bills are high.

Second, Company Witness Spaeth supports a new Optional Seasonal Provision within Tariff R.S. This provision will be available to any residential customer who wishes to opt-in. The Tariff is designed to provide a lower kWh energy rate during December through March when many of our customers experience high usage.

Q. HOW DOES KENTUCKY POWER ASSIST CUSTOMERS IN MANAGING THEIR ENERGY USAGE?

A. The Company is committed to the communities we serve and understands that the effects of long-term economic problems compounded with rising inflation place a strain on our customers, specifically ones on a fixed income and those who fall below the poverty line. The Company acknowledges that inadequate weatherization measures, such as insufficient insulation and weatherstripping around doors and windows, and inefficient heating and cooling systems can increase energy consumption and exacerbate elevated energy bills, further straining low to moderate income households. Less efficient appliances and the lack of a proper building envelope[1] can result in higher-than-normal usage for the size of home. Company employees frequently encounter homes that appear to lack energy efficiency measures. Homes, specifically mobile homes, may lack proper underpinning and insulation. Other homes have damages on the roof, windows, or poorly installed window air conditioning units. Older homes often have electric resistance heat or inefficient heat pump units. Making improvements to a home's appliances and building envelope can significantly decrease usage and therefore lower the monthly bills.

The Home Energy Management program, deployed in 2020, provides residential customers the opportunity to access and manage their energy usage and cost information.

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[1] The building envelope, which includes the walls, windows, roof, and foundation, forms the primary thermal barrier between the interior and exterior environments.

By completing an online home energy analysis, customers gain a better understanding of their energy usage. Customers also receive personalized proactive alerts and energy efficiency tips that help educate customers on managing their energy usage.

In 2021, Kentucky Power through the AEP Foundation provided a $100,000 contribution to the Housing Development Alliance (“HDA") to assist in construction of a much-needed neighborhood in Hazard. The Gurney’s Bend project includes 15 new all-electric homes built to meet a Home Efficiency Rating (“HER”) of 46. The HER rating means the homes use 46 percent of the energy a standard new home uses which translates to about half of the energy consumption of a standard new home and about one-third of the energy consumption of the typical existing home. With that efficiency level, HDA estimates that the combined annual savings of the neighborhood is about $15,000. Kentucky Power through the AEP Foundation also made other contributions toward housing improvements in our communities of $306,100 over the last five years. These contributions benefited Christian Appalachian Project, Housing Development Alliance, and Build Ashland. Although our community support helps in several areas, we plan to continue to be a leader in our region by focusing our efforts in the future to further help the housing situation in eastern Kentucky.

As part of its Demand Side Management (“DSM”) programs, the Company currently provides supplemental funding to Kentucky Housing Corporation’s Weatherization Assistance Program, which assists low-income customers with weatherization and energy efficiency measures. In June 2023, Kentucky Power finalized a DSM Market Potential Study. This study conducted primary market research with customers on their existing energy-consuming equipment as well as their willingness to participate in energy efficiency programs at varying incentive levels. The study identifies cost effective energy efficiency measures and makes recommendations for cost effective programs the Company can implement. The Company intends to file an application to expand its DSM programs within the next year.

Q. HOW DOES KENTUCKY POWER FOCUS ON CUSTOMER CARE?

A. The Company has continued to focus on customer care over the last several years to improve relationships with customers by proactively conducting business and continuing to improve and become a company that is easier to do business with. With each interaction we have with our customers, our goal is to provide great customer service and exceed their expectations. Based on customer feedback from J.D. Power surveys, we recently identified four areas that we plan to review as part of our continued focus on customer care. We plan to look for ways to make Kentucky Power easier to do business with, improve customer communication, make our tariffs easier to understand, and identify federal grant opportunities that will benefit customers.

#1 Easy to Do Business With: Review and implement ideas from field employees that make the Company easier to do business with. One project completed thus far is an easy-to-follow checklist for customers wanting to establish new service. Our field technicians indicated this was a need to help customer better understand the process of obtaining new service.

#2 Communications: How we communicate with customers is changing. Kentucky Power is implementing ways to reach customers through our own communication channels. Our abilities to reach targeted groups of customers has grown through technology. We are sensitive to customers who may not use technology, so we continue to use traditional methods such as bill inserts but we are also finding ways to increase our presence in the community to meet customers where they are. Earlier this year, we held three customer workshops in the Hazard district and invited more than 3,400 customers. The poor turnout was disappointing but was a learning opportunity to determine how customers prefer to interact.

#3 Tariff Review: Several employees will continually review tariffs throughout the year to look for opportunities to improve customer care. This could be something as simple as seeking to rename a tariff to make it more understandable. In fact, the Company is proposing to rename two tariffs and to reorganize and reformat its tariff book in this case for that reason, as explained further by Company Witness Kahn.

#4 Federal grant funding: Kentucky Power is participating in the opportunities from federal grant programs such as Grid Resilience and Innovation Partnerships ("GRIP") and Clean Energy Demonstration Program on Current and Former Mine Land ("CEML"). To date, we have submitted two concept papers, one for GRIP and the other for CEML. We are also exploring potential opportunities and looking for partnerships in other areas, and plan to take advantage of tax credits through the Inflation Reduction Act ("IRA"). Kentucky Power also plans to work with state energy offices to make eligible customers aware of energy efficiency rebates available through the IRA.

Beyond that and thinking about a more progressive future, we have designated Company representatives as specialists in key fields such as energy efficiency, electrification, and electric vehicle infrastructure to ensure we do not miss an opportunity to make meaningful improvements for our customers' benefit.

Q. IN WHAT CUSTOMER COMMUNICATION AND COMMUNITY OUTREACH ACTIVITIES DOES KENTUCKY POWER CURRENTLY ENGAGE?

A. Kentucky Power engages with customers through multiple channels including social media, bill inserts and messages, email, and in-person events. Our educational communications provide customers with the information needed to make informed choices about their accounts. Monthly communication themes are developed which prioritize consistent messaging to build awareness of payment programs and energy efficiency guidelines; storm preparedness; the various ways customer services can assist customers; education on and encouragement for using customer tools available on the Kentucky Power website; and to share news of community outreach participation and philanthropic announcements.

Our website and social media platforms are utilized as a communications method to provide customers with quick and easy access to information. While the website is where customers may read about the various annual community outreach events in which Kentucky Power participates – including a food drive for local pantries, free tree events and a reading day program at local schools – customers can follow our social media page to learn about other community events our employees volunteer for, such as career fairs, mission work and assistance in our local technical college's lineworker program. Customers can also interact with specially trained representatives via social media using direct messages to discuss billing or outage questions.

Email, social media and our website are also critical platforms when providing customers with storm preparation and restoration news and information; electrical grid emergencies and improvements; and other public safety announcements.

Kentucky Power understands how important our communities are. We endeavor to be a good community partner and strengthen our connection with our communities through volunteering and offering customers convenient access to useful information.

Q. HOW HAS KENTUCKY POWER'S APPROACH TO CUSTOMER COMMUNICATIONS AND COMMUNITY OUTREACH EVOLVED SINCE THE LAST BASE CASE?

A. Since the last base case, Kentucky Power has increased frequency of communications with customers and created a quarterly newsletter. Communication efforts now include monthly themes to ensure delivery of messaging is consistent and timely. Coinciding with these themes are the options that benefit customers, including information on the Average Monthly Payment plan ("AMP"), which evens out bill spikes typically experienced in the summer and winter months; and the benefits of downloading our mobile app and signing up for text alerts to stay up to date during outages caused by seasonal weather events. This proactive planning has allowed us to more easily turn our focus on storms or other unexpected events. When we need to shift communications, we can continue rolling out the monthly themes without interruption.

Kentucky Power utilizes information from customer surveys and nationally recognized customer research organizations, such as J.D. Power, to measure customer satisfaction, better understand customer preferences and adjust its customer service efforts according to what is learned from customers. The Company also uses the feedback platform, Medallia, which provides timely feedback from customers, enabling Kentucky Power to address emerging issues more quickly. Furthermore, Kentucky Power participates in outreach events to talk to and interact with customers, to listen and engage in community matters, and monitors social media reactions and comments to gauge customer sentiment.

The Company uses these qualitative measures in conjunction with J.D. Power's customer satisfaction surveys and other research studies to get a comprehensive view of customer satisfaction. Based on 2022 J.D. Power scores, Kentucky Power ranked highest among AEP operating companies for first contact resolution with customers and accurate estimated time of restoration ("ETR") given during outage interruptions.

Promoting our app and text alerts is a priority as those customer preference measurements show a trend toward customer desire for self-service through a website or app. The latest updates include "empathy messaging" to customers experiencing extended outage times to ensure these customers know we are aware of their outage and are still working toward restoration.

Proactive communication continues to be an important part of our communication approach across all customer classes, so we stay engaged with customers to meet their preferences. This year, Kentucky Power sent the first issue of a new quarterly newsletter to residential, commercial and industrial customers who maintain an email address with us. This newsletter will provide information such as industry-related updates, economic development, charitable giving, energy education, and other topics customers will find useful. We have also targeted customers who are delinquent but on life support to see how we can help them; we have targeted customers who we think would benefit from a payment arrangement, or to be on a budget plan.

Kentucky Power takes great care to ensure that its efforts provide customers with accurate and timely information so they can benefit from the wide range of tools and resources the Company offers.

Q. HOW DOES KENTUCKY POWER PLAN TO CONTINUE ITS FOCUS ON CUSTOMER CARE?

A. The Company intends to continue to proactively communicate, listen to our customers and evolve to better meet customer expectations. For example, customers have recently provided feedback that our contributions in aid of construction ("CIAC") payment procedure could be updated to facilitate quicker payments and installation of new services. The Company heard that feedback and instituted a change to its process resulting in same day CIAC payment processing if the customer pays by card.

Kentucky Power, along with other AEP operating companies, participate in a customer experience board where representatives discuss ways to improve customer care. One of the current initiatives for review is further enhancements to the new service process with the goal of a customer request for service portal where customers and contractors can easily follow along in the new service process. Continuing to understand customer needs and implement improvements keeps our focus on customer care.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Stevi N. Cobern, being duly sworn, deposes and says she is the Customer Services Supervisor for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Stevi N. Cobern

Stevi N. Cobern

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stevi N. Cobern, on June 26, 2023.

Scott E. Bishop

Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP32110

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

AMANDA C. CLARK

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
AMANDA C. CLARK ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

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AMANDA C. CLARK ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Amanda C. Clark, and I am an External Affairs Manager for Kentucky Power Company ("Kentucky Power" or "Company"). My business address is 1645 Winchester Ave., Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor's degree in Elementary Education from Marshall University in 2000. I was an elementary school teacher until 2007, when I accepted a management role at the Boyd County Public Library. From 2007 to 2016, I was the programming supervisor for the library system. In 2016, I became the vice president of operations for Ashland Alliance, a regional economic development organization and chamber of commerce.

As the vice president of Ashland Alliance, I gained experience in all aspects of economic development including site development, industrial recruitment, and community development. I completed the University of Kentucky Gatton College of Business and Economics Economic Development Institute and the International Economic Development Council's Economic Development Institute at the University of Oklahoma. Additionally, I have served on the board of directors of the Kentucky Association for Economic

Development since 2020 and have been an active member of the Southern Economic Development Council since 2017.

I joined Kentucky Power as External Affairs Manager in 2019. In addition to my position at Kentucky Power, I have been a member of the City of Ashland's Board of Commissioners since 2014 and have been re-elected to that board four times. The Commission is responsible for setting the policy and budget to manage the city's operations. I represent the city on the Ashland Housing Authority Board, as well as the executive board of Ashland in Motion, an organization committed to the development of downtown Ashland. I also chair the city's capital projects committee.

Q. WHAT ARE YOUR RESPONSIBILITIES AS EXTERNAL AFFAIRS MANAGER?

A. My responsibilities include economic development, managing local government relations, and community outreach.

My responsibilities in economic development include providing support to local and regional economic development partners by assisting with site visits, recruitment trips, and information gathering for consultant requests for potential projects. I also work with the Kentucky Cabinet for Economic Development, the Kentucky Association for Economic Development, One East Kentucky, and the Ashland Alliance to help attract industry to our region. Finally, I manage the Kentucky Power Economic Growth Grant ("K-PEGG") Program. In addition to economic development, I work diligently to maintain relationships with judge executives, mayors, and staff in Kentucky Power's service territory. These relationships are imperative during times of emergency response and helpful for economic development. I am responsible for the northern part of the territory and cover Boyd, Carter, Elliott, Greenup, Lawrence, Lewis, Morgan, Owsley, and Rowan counties. I am also responsible for Kentucky Power's community outreach in those counties. As part of community outreach, I organize staff and resources for community events and volunteer opportunities.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before this Commission in Case No. 2022-00387 (application for a special contract) and Case No. 2022-00424 (application for a special contract under tariffs E.D.R. and D.R.S.).

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe Kentucky Power's economic development efforts and the economic development challenges and successes present in the Company's service territory. My testimony also demonstrates that the Commission should authorize the Company to continue the K-PEGG program and addresses the Company's long-term plan for continuing its economic development in eastern Kentucky.

IV. THE NEED FOR ECONOMIC DEVELOPMENT IN THE COMPANY'S SERVICE TERRITORY

Q. WHY IS ECONOMIC DEVELOPMENT IMPORTANT FOR EASTERN KENTUCKY?

A. The International Economic Development Council defines economic development as "programs, policies and activities that seek to improve the economic well-being and quality of life for a community by creating and retaining jobs and providing a stable tax base."[1] Kentucky Power is actively involved in economic development activities for the sake of its customers and the communities it serves. If eastern Kentucky is going to reverse the trend of companies leaving the region and taking people with them, economic development is the only path forward.

Q. PLEASE DESCRIBE THE ECONOMIC TRENDS IN THE COMPANY'S SERVICE TERRITORY?

A. Kentucky Power's service territory has endured devastating job losses for over a decade. Coal mining employment in eastern Kentucky decreased more than sixfold, falling from 13,372 jobs in 2007 to 2,797 by the first quarter of 2022.[2] In addition, AK Steel in Boyd and Greenup counties, a major employer for the region, ceased operation during the same period. The high rate of job losses in eastern Kentucky has impacted the communities Kentucky Power serves in a variety of ways.

Unemployment Rates

The highest 11 unemployment rates in the Commonwealth are in the Kentucky Power service territory, as summarized in Figure ACC-1 below[3]:

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[1] https://www.iedconline.org/clientuploads/Downloads/Key_Strategies/IEDC_Why_and_Impact_Economic_Development.pdf

[2] Kentucky Center for Economic Policy, *The State of Kentucky Working 2022* https://kypolicy.org/the-state-of-working-kentucky-2022/.

[3] https://www.nkytribune.com/2023/05/kentucky-center-for-statistics-releases-county-unemployment-data-for-april/

Figure ACC-1

County	April 2023 Unemployment Rate (%)
Magoffin	8.5
Lewis	7.3
Martin	6.9
Elliott	6.7
Carter	6.5
Breathitt	5.8
Greenup	5.7
Johnson	5.6
Knott	5.4
Letcher	5.4

By comparison the average unemployment rate over the same period was 3.2% across Kentucky, and 3.1% nationally. [4] Additionally, the labor force participation rate is 42% in Kentucky Power's service territory compared to the US average of 63%. The unemployment rate and low labor participation rate drags down the average household income in the territory to $40,000 compared to $70,000 nationally and creates a situation where 27% of the residents live in poverty (12% is the US average).

<u>Population Loss</u>

With the loss of jobs, the territory lost population. Between 2008 and 2022, the Company's service territory lost 39,350 people.[5] To put that number in perspective, that total is more than the population of Greenup County. It is also more than the populations of Owsley, Elliott, Leslie, and Martin counties combined.

<u>Economies</u>

Business closures, and the resultant job and population losses, have significant impact on Kentucky Power's communities' economies. By way of illustration, Kentucky

[4] https://www.nkytribune.com/2023/05/kentucky-center-for-statistics-releases-county-unemployment-data-for-april/
[5] https://www.census.gov/

Power utilized IMPLAN (an economic impact software nationally recognized and accepted by economic development professionals) to model the impact of the 240 jobs lost at AK Steel when it closed its doors in late 2019. IMPLAN is a micro-computer-based input-output ("I-O") modeling system. The IMPLAN model looks at the impacts of ongoing economic activity and capital investments [6] and quantifies them. With IMPLAN, one can estimate I-O models of up to 528 sectors for any region consisting of one or more counties. In modeling AK Steel's economic impact on the local area, the model specifically considered Kentucky Power's Service territory and employment analysis for AK's specific industry (steel manufacturing).

IMPLAN's Ongoing Economic Activity results consider the annual impact of 240 steel manufacturing jobs as represented by the production, purchase or sale of products or services as well as working for a wage or salary in the local area.

Figure ACC-2 provides IMPLAN's results for the ongoing economic activity (now gone) associated with the 240 AK Steel jobs in Kentucky Power's service territory. The AK Steel jobs represented 240 direct employee and 630 total jobs in the local economy.

Figure ACC-2

Impact Type	Employment	Labor Income	Value Added	Output
1-Direct effect	240.00	$33,333,348.80	$73,098,770	$263,453,614.87
2-Indirect	217.09	$13,026,665.84	$22,448,050.24	$51,427,721.60
3-Induced	173.10	$8,056,012.23	$14,565,629.03	$26,390,941.09
Total	630.18	$54,416,026.88	$110,112,456.97	$341,272,277.55

[6] Money used by a business to purchase fixed assets such as land, machinery, or buildings.

Direct effect refers to the employment, labor income, and value-added effects for the jobs specifically to operate the AK Steel plant. *Indirect* effect refers to the employment, labor income and value-added effects of the business-to-business purchases (goods or service) within AK Steel's supply chain resulting from AK Steel's facility being located in the area. *Induced effect* refers to the value added within the local economy stemming from household spending of labor income which is generated by the spending of the employees. [7]

Q. HOW HAS THE DOWNWARD ECONOMIC TREND IN KENTUCKY POWER'S SERVICE TERRITORY IMPACTED THE COMPANY?

A. The high unemployment rate impairs our customers' ability to pay for goods and services, including electricity. Population loss translates to customer loss for Kentucky Power. Between 2008 and 2022, the Company lost 11,462 customers and has seen its total annual weather normalized sales fall by 1,879 GWh, or 25.5 percent. Generally speaking, sales represent the denominator in utility rate making and thus loss of load directly correlates to increased rates for the remaining customers.

Q. HOW DOES EASTERN KENTUCKY COMPARE TO OTHER PARTS OF THE COMMONWEALTH WITH RESPECT TO ECONOMIC DEVELOPMENT?

A. Kentucky Power's service territory is relatively new to the concept of economic development, and this puts it at a disadvantage when compared to other regions in Kentucky. For example, Greater Louisville, Inc., the regional chamber of commerce/economic development organization for the metro-Louisville area, has been

[7] Please see https://blog.implan.com/understanding-implan-effects for further information on these terms.

involved in economic development activities since 1987, while One East Kentucky, the largest regional economic development organization in eastern Kentucky, began operations in 2015. Regions like central Kentucky have a nearly 30-year head start in identifying sites and preparing them for economic development.

Additionally, eastern Kentucky faces a particular hardship because of its lack of economic diversity. The decline of coal and the closure of major manufacturers across the region have left eastern Kentucky in need of residents and a tax base. Many of the communities in Kentucky Power's service territory also do not have the resources to be actively involved economic development activities.

Finally, eastern Kentucky's terrain makes large, quality sites for economic development scarce. Many of the sites without a significant slope are hindered by flood plain issues. The regional industrial parks in the Company's service territory are re-claimed strip mine sites that face a unique set of building challenges as well.

V. KENTUCKY POWER'S ECONOMIC DEVELOPMENT EFFORTS

Q. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO SUPPORT ECONOMIC DEVELOPMENT IN ITS SERVICE TERRITORY.

A. Kentucky Power recognizes the importance of healthy local economies and takes a leadership role in economic development in eastern Kentucky. Since 2012, Kentucky Power has worked diligently with economic development organizations to promote business investment, site development, job creation, and load growth in eastern Kentucky.

The Company's efforts are also aimed at recruiting industry and making capital investments in its service territory, thereby increasing employment opportunities, and expanding the tax base. Loss of jobs is crippling many of the communities in the

Company's service territory. The population loss that has occurred as a result is leaving local governments scrambling for resources as the tax base is dwindling.

Kentucky Power works closely with and supports local economic development organizations to focus on key aspects in its economic development efforts: industry retention, industry expansion, industry attraction, and site development. New and diversified economic activity in the Company's service territory benefits both customers and the Company.

Additionally, the external affairs managers as well as Kentucky Power's president and COO are all graduates of the University of Oklahoma Economic Development Institute and are experienced practitioners of economic development. Kentucky Power holds seats on the boards of the Ashland Alliance, One East Kentucky, Hazard-Perry County Economic Development Alliance, and the Kentucky Association for Economic Development. Further, Kentucky Power representatives regularly participate in board meetings for the area development districts, industrial park authorities and workforce development. Kentucky Power eagerly lends its knowledge and assistance to its communities for economic development activities.

Q. DOES THE COMPANY HAVE ANY OTHER ECONOMIC DEVELOPMENT-FOCUSED PROGRAMS IN PLACE?

A. Yes. Since 2015, Kentucky Power has administered and contributed to funding the K-PEGG Program, which provides grant funding targeted specifically at projects designed to enhance the economic development potential of the communities in the Company's service territory. In Case No. 2014-00396, the Commission recognized the importance of a region's utility in economic development when it first approved the Company's

Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S."), which funds the K-PEGG Program. The K-PEGG program is funded through Tariff K.E.D.S. at the rate of $1.00 per non-residential meter per month with a corresponding dollar-for-dollar Company match.

Q. PLEASE FURTHER DESCRIBE THE K-PEGG PROGRAM.

A. K-PEGG funding is awarded for use in the following categories: Economic Development Education, Sites and Buildings-Product Improvement, Marketing and Promotion, and Professional Consulting Services. The program allows Kentucky Power to work strategically with communities, government, and economic development partners to facilitate business location and expansion specific to the Company's twenty-county service territory. Here is a brief description of each K-PEGG Program category:

<u>Economic Development Education</u>

The focus of this category is to provide educational opportunities to local economic development practitioners within the Company's service territory. These opportunities seek to raise the bar of performance for our communities and partners that are focused on economic development. Funds from this category have facilitated education for economic development professionals in the service territory.

<u>Sites and Building-Product Improvement</u>

In 2012, Kentucky Power engaged InSite Consulting Group to identify areas of improvement in the region's industrial sites. The criteria for this category were based around these recommendations and include infrastructure improvements, master plan updates, due diligence items, site compaction and Build Ready certification, and "close the deal" funding.

This category is designed to bring to market new or existing sites and facilities within the Kentucky Power service territory and position communities to compete successfully for new jobs and investment or to retain existing jobs. The product improvement funds allow partner communities to leverage local, state, federal and private participation in economic development projects and make sites competitive in the site selection process.

Site selection involves measuring the needs of a new project against the merits of potential locations. A formal process became widely accepted post WWII when large companies needed to identify ideal locations for new corporate campuses and manufacturing operations as the US population and economy expanded. Bringing properties to market is critical for success in economic development. Regional economic development partners rely on K-PEGG funding to meet this important need.

According to Site Selection Group, a leading provider of global location advisory, economic incentive and corporate real estate services:

> There is little that is more frustrating to an economic developer than having high levels of prospect activity and having no buildings or sites to show. Exacerbating the issue is that companies' deadlines to select a site and bring products to market are getting shorter and shorter. To compete for jobs and investment, economic developers are becoming more engaged and taking a leadership role to provide viable real-estate options to prospects [8]

Many industrial sites in Kentucky Power's territory are former mine land sites, often referred to as "fill sites." Due to this fact, these sites are often at a competitive disadvantage because each building site must be compacted before a foundation can be

[8] https://info.siteselectiongroup.com/blog/navigating-the-site-development-process

constructed. This can add significant cost to build on a site and makes some eastern Kentucky sites less competitive for industry.

<u>Marketing and Promotion</u>

K-PEGG lends support to regional economic development organizations who serve as the primary marketing arm in the region's economic development activities. The organizations tasked with marketing industrial properties in eastern Kentucky have limited funding. Industrial authorities are in place to manage most of the properties but lack any funding to do property improvements or marketing; especially with the decline of the coal severance dollars that previously would typically fund these activities for industrial parks.

<u>Professional Consulting Services</u>

The use of consultants is often necessary for to provide a skill or resource that is not readily available in a community or government or to provide a targeted approach to an effort that will ensure strategic investment of time and money.

Q. WHAT RESULTS HAVE BEEN REALIZED FROM THE COMPANY'S ECONOMIC DEVELOPMENT FOCUS?

A. Kentucky Power and its economic development partners continue to work to remove barriers to development. By working together, the region has produced certified and build-ready sites and quantified the skills of its workforce so that it can be ready for potential projects. Together, through these key aspects of economic development, Kentucky Power and its community, government, and economic development partners work diligently to build a stronger eastern Kentucky.

The Company's K-PEGG Program also has realized success in each of the categories for which that program awards funding:

Economic Development Education

Regional economic development organizations have used K-PEGG awards to host economic development training for 67 elected officials. Economic development education is important for local officials. Economic development education will help them understand the factors that attract investment to a community and the importance of strategic planning and partnerships. Educated officials will be able to set clear goals for their communities and have the skills to work collaboratively to reach those goals. Local officials with economic development training will be better equipped to identify and pursue funding opportunities for economic development projects.

Sites and Building-Product Improvement

A particular success in site development is found in Paintsville. The Johnson County Fiscal Court was approved for a K-PEGG in 2021 to complete due diligence on the Hager Hill Industrial Site. Johnson County leveraged the K-PEGG results to achieve Build-Ready certification from the Kentucky Cabinet for Economic Development. The Build-Ready designation means necessary permits, including water, environmental, archeological, and geotechnical studies are on file, as well as preliminary building plans, cost estimates and schedule projections. It is common for K-PEGG to assist with these preliminary studies ahead of the site certification process. Sites will not be considered Build-Ready without them.

After achieving Build-Ready certification, Johnson County applied and was approved for a Kentucky Product Development Initiative ("KPDI") grant. Johnson County intends to purchase the property adjacent to the existing park, doubling the size of the industrial park.

KPDI, is a partnership between the Kentucky Cabinet for Economic Development and the Kentucky Association for Economic Development ("KAED"). In 2018, KAED was approved for a K-PEGG to support its pilot of KDPI. KPDI was developed to address a shortage of top-quality locations in the Commonwealth. KPDI grants are awarded for utility infrastructure upgrades, property acquisition, facility enhancement or due diligence necessary to prepare sites and buildings for investment. The initiative enhances quantity and quality of Kentucky's available sites and buildings, addresses the lack of capital in a market and encourages collaboration among Kentucky economic developers and stakeholders to help new and expanding businesses find a suitable location more quickly.[9]

EastPark in Ashland also benefited from a KPDI grant in 2023. The grant allowed EastPark to purchase the former Unity Aluminum site, which is also Build-Ready Certified with K-PEGG funds. The site is important to the region as it has the only 100,000 square foot speculative building available in the state.

An additional product the Kentucky Power service territory has to market is its workforce. K-PEGG has funded two studies of the region's workforce. Those studies quantify the number of workers available for a prospect and qualify their skills. The studies concluded that the region's workforce possessed the skills necessary to transition to aerospace, aviation, and advanced manufacturing sectors. This workforce information has been valuable to the state, our regional partners, and the Company for recruitment. The information in the study has been noted as a major factor in the location of

[9] https://ced.ky.gov/Newsroom/NewsPage/04252019_KAED

companies like Dajcor, Danieli; a metal industry supplier located in Ashland and Omnis Building Technologies; a building materials manufacturer located in Greenup.

K-PEGG has also assisted in site development that will train the workforce of the future and re-train the numerous displaced coal and steel workers in our service territory by assisting eKentucky Advanced Manufacturing Institute with upgrades to its training equipment and Galen School of Nursing with expanding its facilities to train additional nurses.

Marketing and Promotion

In 2020, One East Kentucky leveraged K-PEGG funds as a match for a $1.2 million grant from the Appalachian Regional Commission to recruit new industry, develop industrial sites, and build a robust business retention and expansion program.[10] SOAR also used K-PEGG funds to create EKY Remote, a marketing campaign to recruit remote workers to the region.[11]

Kentucky Power fully funded through K-PEGG the AEROready™ Certification process for its service territory. AEROready™ certification involves a deep analysis of items to ensure that regions, site, and communities certified reduce risks for potential aerospace companies. The certification validates the region as ready for aerospace industry, that there is a supply of labor and opportunity, and that necessary infrastructure is in place. The certification process provided Kentucky Power's regional economic development organizations analyzed data, a recruiting plan and a SWOT (strengths,

[10] https://halrogers.house.gov/2020/9/congressman-rogers-announces-1-2-million-grant-for-opportunity-east-kentucky
[11] https://ekyremote.com/

weaknesses, opportunities and threats) analysis to better prepare them to recruit aerospace projects to the regions.

<u>Professional Consulting Services</u>

K-PEGG awards for professional consultants include broadband studies for Pikeville, gap analysis for industrial sites in Greenup County, strategic planning for Ashland, Jenkins, Prestonsburg, Pikeville, Whitesburg, and Hazard, and site identification in Lawrence County.

The City of Pikeville used K-PEGG funds to study broadband feasibility in 2016. This study was then used by the city to plan its broadband network. In 2022, Pikeville announced its partnership with Intermountain Cable/Gearheart fiber to build its network. Broadband is considered critical infrastructure for recruitment and Pikeville anticipates its deployment to lead to many opportunities for the community.[12]

K-PEGG assisted Ashland Alliance with a gap analysis study of industrial sites in Greenup County. This analysis assisted Greenup County and EastPark Industrial Park in identifying flaws to existing industrial sites. Since the study, K-PEGG has assisted in extending a road to allow for easier access to the Build Ready site in EastPark and a road plan for access to the South Shore Industrial Site.

The City of Ashland and One East Kentucky engaged consultants to assist Ashland, Jenkins, Prestonsburg, Pikeville, Whitesburg and Hazard with strategic development plans in 2022. Those plans are targeted at downtown development to retain population and enhance the quality-of-life aspect for recruitment.

[12] https://www.wymt.com/2022/11/16/officials-give-update-pikeville-broadband-project/

Lawrence County used K-PEGG funds for professional consulting to identify potential industrial sites, determine their flaws, and create a plan to bring them to market. Lawrence County intends to use the results of the study to apply for KPDI funds for site development.

VI. ECONOMIC DEVELOPMENT PROPOSALS IN THIS CASE

Q. HOW DOES THE COMPANY PLAN TO CONTINUE TO SUPPORT ECONOMIC DEVELOPMENT IN EASTERN KENTUCKY?

A. Kentucky Power will continue its leadership role in economic development for eastern Kentucky. Dividends from economic development efforts are often long-awaited but critical to the Company's service territory. To maintain progress and encourage further economic development of its service territory Kentucky Power is proposing to continue the K-PEGG program and maintain Tariff K.E.D.S. at the rate of $1.00 per meter per month for its non-residential customers with the Company's dollar-for-dollar match.

Q. HOW WILL THE CONTINUATION OF THE K-PEGG PROGRAM BENEFIT KENTUCKY POWER'S CUSTOMERS?

A. Economic development is the engine that drives community economies in Kentucky Power's service territory. Through the collaborative work that Kentucky Power does with workforce development agencies, local economic development organizations, local units of governments, and private developers, we are helping to create critically needed jobs, diversify our economy, provide existing businesses with tools to compete and grow, increase the tax base for our local communities, and provide training and opportunities for an already highly skilled workforce in eastern Kentucky. A vibrant, growing economy helps all customers by increasing the customer base over which the fixed costs of Kentucky Power's operations can be spread.

The K-PEGG Program that Kentucky Power proposes to continue in this case directly addresses the primary economic development challenges that exist in Kentucky Power's service territory. In addition to having a skilled workforce, it is also critically important that economic development organizations in Kentucky Power's service area are equipped with an inventory of prospective buildings and sites to incentivize business expansions within the service territory or new businesses to locate within the service territory. Kentucky Power currently works with many of our economic development organizations and local communities to aggressively pursue business opportunities for the Company's service area. Not having an adequate inventory of available facilities can be a competitive disadvantage when competing for some opportunities. Utilizing the K-PEGG Program to continue to incentivize local governments and developers to invest in our communities will result in new jobs for our customers, increased investments in our local communities, and an expanded customer base to share in Kentucky Power's fixed costs.

Success in economic development takes time. Kentucky Power and its territory are a little more than a decade in a long game. The region has seen a bit of success, but the economic hardships the area faces demonstrate that more is needed. Economic development is part of Kentucky Power's long-term strategy to support the region's revitalization. The Company and its partners have laid the groundwork by getting sites ready, quantifying the region's attributes in workforce and transportation, and developing marketing strategies to recruit to the region. The Commonwealth of Kentucky is seeing record years in economic development investment and many of the potential projects have been sent to eastern Kentucky to compete. Since the beginning of 2023, Kentucky Power and its partners have submitted 21 requests for information from companies looking to locate a project. Those projects potentially represent more than $17 billion in capital investment and nearly 17,000 jobs. The region is just beginning to see the opportunity presented by having available sites in a unique period of growth in the Commonwealth.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Amanda C. Clark, being duly sworn, deposes and says she is the External Affairs Manager for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Amanda Clark

Amanda C. Clark

Commonwealth of Kentucky	)	
	)	Case No. 2023-00159
County of Boyd	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Amanda C. Clark, on June 15, 2023.

Scott E. Bishop

Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2023-00159
Regulatory Assets And Liabilities; (4) A	)	
Securitization Financing Order; And (5) All Other	)	
Required Approvals And Relief	)	

DIRECT TESTIMONY OF

EVERETT G. PHILLIPS

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
EVERETT G. PHILLIPS ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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EXHIBIT EGP-4	DRR Work Plan (2024-2028)

DIRECT TESTIMONY OF
EVERETT G. PHILLIPS ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Everett G. Phillips. My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101. I am the Vice President of Distribution Region Operations for Kentucky Power Company ("Kentucky Power" or "Company").

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a bachelor's degree in Electrical Engineering in 1985 from West Virginia University and a master's degree in Business Administration in 2007 from University of Phoenix. I am a registered professional engineer in the Commonwealth of Kentucky. I have over 38 years of electric utility operations experience in the areas of distribution construction design and engineering, major storm restoration, business continuity planning, and management.

Throughout my career, I have held positions of increasing responsibility within the utility space. After graduation from college in 1985, I began my career as an electrical engineer in Huntington, West Virginia for Appalachian Power Company, an affiliate of Kentucky Power. In 1994, I was promoted to Appalachian Power area supervisor in Clintwood, Virginia. In 1998, I was promoted to the Kentucky Power

Pikeville district superintendent position, and in 2000, I was promoted to the Pikeville district manager. In 2004, I moved to Ashland, Kentucky, where I served as Director of Customer and Distribution Operations. In 2017, I was promoted to Managing Director of Distribution Region Operations, and in 2019 my title changed to Vice President of Distribution Region Operations.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF DISTRIBUTION REGION OPERATIONS?

A. I am responsible for overseeing all aspects of the Company's distribution system including its planning, construction, operation, and maintenance. My duties include the safe and reliable delivery of service to customers, the oversight and management of service extensions to new customers, and the restoration of service when outages occur. I am also responsible for Kentucky Power's Distribution Vegetation Management Program and oversee the Company's distribution grid modernization investments for reliability improvements.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before this Commission in the Company's base rate case filings, Case Nos. 2009-00459, 2014-00396, 2017-00179 and 2020-00174. My testimony in each proceeding focused on the Company's Distribution Vegetation Management Program and system reliability.

III. <u>PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides an overview of the Kentucky Power distribution system and describe the operating challenges the Company currently faces with respect to distribution. I will also describe the Company's distribution reliability programs aimed at addressing those challenges. My testimony also discusses the Company's reliability performance indices and how the Company's reliability programs, including the Distribution Vegetation Management Program ("Vegetation Management Program"), positively impact reliability performance. I support the Company's request to continue the one-way balancing mechanism associated with its Vegetation Management Program. I also describe the distribution system capital investments made since the Company's last base rate case (Case No. 2020-00174) and the test year per book level of operation and maintenance ("O&M") expense for distribution operations.

In order to further address the reliability needs of the Company's system, I am also supporting the Company's proposal to implement the Distribution Reliability Rider ("DRR"). The Company's proposed DRR includes a suite of programs to address the most prevalent challenges and leading outage causes experienced on the Company's system improving reliability for our customers.

Finally, I will provide an update on Kentucky Power's Smart Grid investments consistent with the Commission's Order from Case No. 2012-00428.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibit attached to my testimony:

Exhibit	Description
EXHIBIT EGP-1	Map of Kentucky Power Service Territory
EXHIBIT EGP-2	Map of Kentucky Vegetation Density
EXHIBIT EGP-3	Jackson, KY National Weather Service Historical Data
EXHIBIT EGP-4	DRR Work Plan (2024-2028)

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSALS RELATED TO DISTRIBUTION SYSTEM INVESTMENT AND O&M IN THIS PROCEEDING.

A. The Company is requesting to continue the one-way balancing mechanism associated with its Vegetation Management Program. This is based on an annual budget amount equal to its actual test year Vegetation Management Program O&M expense of $22.4 million, as shown on Application Section V, Exhibit 2 W43**.** As explained later in my testimony, the Company is proposing to continue its 5-year cycle for trees inside of rights-of-way ("TIR").

The Company is proposing to implement the DRR to improve reliability for our customers through planned additional distribution investment and associated O&M. Specifically, through the DRR, the Company is proposing to expand its efforts to widen its ROW to address trees outside of rights-of-way ("TOR") and falling limbs. Through the DRR, the Company will also make additional distribution investments to address equipment-related outages, address operating challenges related to the current system configuration, and further harden the Company's distribution system. The initial DRR Work Plan is a five-year work plan (2024-2028). The proposed estimated capital and O&M spend through the DRR for the first year (2024) is $19.4 million. I describe the DRR in further detail in Section IX of my testimony and summarize the costs in Figure EGP-10.

IV. DESCRIPTION OF THE KENTUCKY POWER DISTRIBUTION SYSTEM

Q. PLEASE DESCRIBE THE DISTRIBUTION SYSTEM THAT SERVES KENTUCKY POWER'S CUSTOMERS.

A. Kentucky Power serves approximately 163,400 retail customers in Kentucky in a service area that covers approximately 3,787 square miles. Kentucky Power's distribution system includes approximately 233 distribution circuits, approximately 9,919 miles of primary and secondary overhead distribution lines, and approximately 189 miles of primary and secondary underground distribution lines. The Company's 10,108 miles of overhead and underground distribution lines operate at voltages between 2.4 kV to 34.5 kV.

Kentucky Power's distribution system was originally designed to serve coal mining operations that were prevalent throughout its service territory in the 1970s-80s. As such, the Company's distribution system consists largely of long 34.5 kV and 12.47 kV circuits, that average 62.1 and 34.0 miles in length, respectively, with the longest circuit covering 173 primary line miles. A map of Kentucky Power's service territory is attached hereto as Exhibit EGP-1.

V. KENTUCKY POWER'S INVESTMENT IN ITS DISTRIBUTION SYSTEM SINCE THE LAST BASE RATE CASE

Q. HOW MUCH CAPITAL HAS KENTUCKY POWER INVESTED IN ITS DISTRIBUTION SYSTEM SINCE THE LAST BASE CASE?

A. The Company invested approximately $256.9 million in its distribution system from April 1, 2020, through March 31, 2023.

A breakdown of Kentucky Power's distribution capital additions per year for each general project category is shown in Figure EGP-1.

Figure EGP- 1 – Kentucky Power Distribution Capital Additions by Year ($)

	4/1/20-12/31/20	1/1/21-12/31/21	1/1/22-12/31/22	1/1/23-3/31/23	4/1/20-3/31/23	4/1/22-3/31/23
CATEGORY	**2020**	**2021**	**2022**	**2023**	**TOTAL**	**Test Year**
Asset Improvement	$7,954,481	$14,570,335	$13,783,891	$4,453,006	$40,761,713	$15,824,427
Customer Service	$10,495,460	$12,412,159	$11,052,136	$3,632,774	$37,592,529	$11,512,875
Vegetation Mgmt. Program	$6,388,589	$9,970,789	$9,633,203	$8,032,775	$34,025,356	$10,227,264
Other	$42,609	$24,405	$3,117	$120,593	$190,724	$123,580
Planning Capacity	$634,500	$7,704,389	$303,804	($68,891)*	$8,573,802	$61,839
Reliability	$8,692,524	$6,005,792	$4,737,388	$1,500,956	$20,936,660	$5,059,549
System Restoration	$9,067,463	$21,747,237	$15,462,491	$1,355,257	$47,632,448	$14,946,733
Sub-Total	**$43,275,626**	**$72,435,106**	**$54,976,030**	**$19,026,470**	**$189,713,232**	**$57,756,266**
Intangible Plant	$4,750,228	$5,321,280	5,062,347	$928,312	$16,062,167	$5,276,308
General Plant	$2,818,472	$9,554,380	$36,746,819	$2,024,735	$51,144,406	$37,954,681
Sub-Total	**$7,568,700**	**$14,875,660**	**$41,809,166**	**$2,953,047**	**$67,206,573**	**$43,230,989**
Total	**$50,844,326**	**$87,310,766**	**$96,785,196**	**$21,979,517**	**$256,919,805**	**$100,987,255**

* Negative number is the result of excess material returned to stock on a distribution substation project.

Q. PLEASE DESCRIBE THE NATURE OF THESE DISTRIBUTION CAPITAL ADDITIONS.

A. Capital additions represent the annual investment in distribution infrastructure needed to provide reliable electric service to new and existing customers. The Company invests in the following general capital project categories:

- <u>Asset Improvement</u> – projects include replacement of outdated, failing equipment, and other necessary infrastructure upgrades needed to maintain safe and reliable electric service for Kentucky Power customers.

- <u>Customer Service</u> – work required to connect new customers and customers who upgrade their facilities to the distribution system as well as the costs of the necessary transformers and meters.

- <u>Vegetation Management Program</u> – includes capital work for the TIR and TOR programs, performed by Kentucky Power's Forestry department, to widen existing clearance zones, remove large trees inside and outside of the ROW, or to establish a new clearance zone for new construction.

- Other - miscellaneous projects, as well as distribution projects that support other business units, including distribution upgrades made in response to a transmission system change.

- Planning Capacity - comprised of projects developed as part of Kentucky Power's long-range planning for meeting electrical load on Kentucky Power's distribution system. The need for capacity expansion can be due to either new customers or new load by existing customers in an area. While the Company is seeing an overall decrease in customers, there are pockets of growth that must be addressed on individual stations or circuits where the loading has increased.

- Reliability - investments that target known reliability issues affecting groups of customers or whole circuits experiencing reliability issues. This work includes activities such as replacing poles, installing lightning mitigation, replacement of crossarms, small conductors, addition of sectionalizing devices, as well as necessary upgrades to allow for additional switching on the distribution system to improve the resiliency of the distribution grid in these targeted areas.

- System Restoration – involves restoring electrical service following an unplanned event. These are typical system restoration projects, such as replacing poles, reconductoring full-length spans, and replacing transformers damaged during a storm or weather-related event, generally caused by TOR. This category also includes the replacement of streetlights and outdoor area lights.

Q. DID KENTUCKY POWER MAKE OTHER CAPITAL INVESTMENTS SINCE THE LAST RATE CASE?

A. Yes. The Company also made distribution -related intangible and general plant capital investments since the last rate case.

Intangible capital projects are routine software updates and new programs that increase the efficiency of Kentucky Power's Distribution organization.

Additionally, as shown in Figure EGP-1, the total amount for Distribution-General Plant since the Company's last rate case is $51.1 million. The majority of these costs are related to:

- Telecommunication upgrades necessary to improve internal Kentucky Power communications. These upgrades allow for more efficient transfer of information and data within the Company. For field employees, these upgrades facilitated improvements to radio systems that provided a more reliable connection to organizations such as dispatch and service centers.
- Buyout of existing Kentucky Power leases (excluding land leases). These buyouts converted leased assets to owned assets on the books of the Company. The bought-out leases consist primarily of Fleet, Telecom, Mobile Handling Equipment and Technology equipment.

Q. WHAT WAS THE ANNUAL LEVEL OF KENTUCKY POWER'S DISTRIBUTION O&M EXPENSE FOR THE PERIOD 2020-2022 AND THE TEST YEAR?

A. Figure EGP-2 shows Kentucky Power's per book (unadjusted) distribution O&M expenses by FERC Account for calendar years 2020 through 2022, and for the test year.

Figure EGP-2 –Kentucky Power Distribution O&M Expenses ($)

	FERC ACCT	2020	2021	2022	Test Year
Distribution Operation	5800	$758,510	$829,970	$805,659	$842,415
	5810	$312	$3,410	$1,964	$2,549
	5820	$222,575	$259,294	$388,479	$413,460
	5830	$692,064	$397,079	$351,141	$288,721
	5840	$151,144	$152,750	$238,861	$236,693
	5850	$83,521	$78,060	$46,816	$60,855
	5860	$1,379,775	$1,151,401	$1,229,732	$1,179,733
	5870	$201,141	$193,715	$200,910	$206,568
	5880	$4,770,802	$2,424,122	$3,192,387	$3,637,288
	5890	$1,386,488	$242,074	$933,528	$937,317
Total		$9,646,332	$5,731,877	$7,389,475	$7,805,598
Distribution Maintenance	5900	$3,036	$26,434	$5,110	$7,828
	5910	$111,506	$8,122	$20,773	$19,055
	5920	$337,490	$683,774	$337,440	$307,280
	5930	$32,329,792	$33,683,296	$33,194,092	$35,399,412
	5940	$78,228	$19,443	$48,395	$51,244
	5950	$45,466	$52,827	$23,586	$30,987
	5960	$57,121	($8,742)**	$20,854	$11,275
	5970	$34,857	$50,515	$33,477	$30,875
	5980	$41,156	$20,541	$25,517	$23,125
Total		$33,038,652	$34,536,208	$33,709,243	$35,881,083
Distribution Operation		$9,646,332	$5,731,877	$7,389,475	$7,805,598
Distribution Maintenance		$33,038,652	$34,536,208	$33,709,243	$35,881,083
Total		**$42,684,984**	**$40,268,085**	**$41,098,719**	**$43,686,680**

* **Note**: negative number is generally the result of reimbursements for make ready work related to pole attachments.

Q. PLEASE DISCUSS THE TEST YEAR O&M EXPENDITURES VS. HISTORICAL SPEND.

A. The Company's test year O&M is showing a slight increase to historical spending, primarily related to FERC Account 5930 – Maintenance of Overhead Lines. Company Witness Whitney supports various adjustments to test year Distribution O&M expense, including adjustments to normalize the level of storm-related expense in FERC Account 5930. Company Witness West supports the Company's overall Kentucky retail jurisdiction annual revenue requirement, which reflects an adjusted Distribution O&M of $36.2 million, composed of the following items shown in Figure EGP-3:

Figure EGP-3–Kentucky Power Adjusted Distribution O&M Expenses

Adjusted Kentucky Retail Jurisdiction Distribution O&M	FERC Account	Description	Amount Requested
Distribution Operation	5800-5890	Distribution Operation Expense	$8.0 million
Distribution Maintenance	5930	Vegetation Management Program	$22.4 million
		Major and Non-Major Storm Projects	$1.0 million
		Other Distribution Maintenance Overhead Line Expense	$4.0 million
	5900-5920; 5940-5980	Other Distribution Maintenance Expense	$0.8 million
Distribution Maintenance	5900-5980	Distribution Maintenance Expense	$28.2 million
Total		Distribution O&M Expense	**$36.2 million**

Q. IS THE TEST-YEAR AMOUNT REQUESTED FOR O&M REASONABLE?

A. Yes. The test-year amounts of O&M are in line with the Company's historical O&M expenditures since its last base rate case. This represents the amount necessary for the Company to continue to provide safe and reliable service to its customers. In order to further improve reliability for customers, the Company is proposing the DRR, which has associated O&M not included in the test year amount.

VI. RELIABILITY INDICES AND PERFORMANCE

Q. HOW DOES KENTUCKY POWER MONITOR AND TRACK RELIABILITY PERFORMANCE?

A. The primary metrics used to gauge service reliability are System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), Customer Average Interruption Duration Index ("CAIDI"), Customer Minutes of Interruption ("CMI"), and Customer Interruption ("CI"). These metric data are analyzed for historical trends by area and outage cause, which ultimately is used in planning the reliability work.

SAIFI is the average frequency of sustained interruptions per customer over a predefined area. It is the total number of (sustained) customer interruptions divided by the total number of customers served. Kentucky Power measures SAIFI in terms of events on a rolling twelve-month basis. Kentucky Power considers SAIFI to be general indicator of the condition of an electric system under most circumstances.

SAIDI represents the total time the average customer is without service due to sustained interruptions over a predefined period of time. It is the sum of customer minutes of interruption from each outage divided by the total number of customers served. Kentucky Power measures SAIDI in minutes on a rolling twelve-month basis. SAIDI is equal to the product of SAIFI and CAIDI. Kentucky Power considers SAIDI to be a balanced general indicator of overall system performance.

CAIDI is the average time needed to restore service to the average customer per sustained interruption. It represents the sum of customer interruption durations divided by the total number of customers interrupted. Kentucky Power measures CAIDI in minutes on a rolling twelve-month basis. Kentucky Power considers CAIDI to be a general indicator of response and recovery performance when sustained outages occur.

Kentucky Power also tracks CMI when evaluating system reliability performance. CMI is a subset of CAIDI and represents the total number of customers that experience a sustained outage multiplied by the duration of each customer interruption.

Kentucky Power calculates and reports SAIFI, SAIDI and CAIDI indices without Major Events to provide a more realistic view of how the system operates during most operational conditions. Major weather events are typically excluded from the calculation of these industry standard metrics to better represent system performance during normal conditions and to allow for more consistent comparisons with other utilities and industry averages.

Q. WHAT ARE MAJOR STORM EVENTS AND WHY ARE THEY EXCLUDED IN FIGURE EGP-4?

A. IEEE 1366-2017, the "IEEE Guide for Electric Power Distribution Reliability Indices," defines a major event as "an event that exceeds reasonable design and or operational limits of the electric power system." A Major Storm Event includes at least one Major Event Day ("MED")." A MED is defined as "a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purpose of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather)." The IEEE standard uses an accepted statistical approach to determine when it is appropriate to exclude a major event. By excluding major storm events, which by definition are storm events that exceed reasonable design or operational limits, the Company also is able to give the Commission a clearer picture of the progress being made to improve the Company's reliability.

Q. PLEASE PROVIDE THE COMPANY'S RECENT SAIFI, CAIDI, AND SAIDI PERFORMANCE.

A. The Company's SAIFI, CAIDI, and SAIDI indices for 2017 through 2022 are shown in Figure EGP-4.

Figure EGP-4 SAIFI, CAIDI, SAIDI Performance Indices

Year	**SAIFI**	**CAIDI**	**SAIDI**
2017	2.169	187.3	406.3
2018	2.342	206.8	484.2
2019	2.485	195.2	485.0
2020	2.010	197.7	397.4
2021	1.852	217.1	402.1
2022	2.289	214.3	490.6

The increase in SAIDI and SAIFI for 2022 as compared to prior years was caused by unusually stormy Major Storm Event and non-Major Storm Event weather conditions during the year. For example, in July of 2022, Kentucky Power's service territory experienced a historic 1000-year probability flooding event that is described in more detail by Company Witness Blankenship. Additionally, beyond this flooding event, there were 17 storm days recorded in July 2022. Excluding the MEDs for July 2022, customers experienced 18.8 million CMI resulting primarily from this severe weather. January 2022 also stood out as the Company experienced thunderstorms, rain, and flooding that although were severe, did not include any MEDs, yet still totaled 9.6 million CMI. The non-MED minutes for both January 2022 and July 2022 that were in excess of historical averages (2018-2021) were equivalent to an increase of over 102.2 minutes to the Company SAIDI.

Q. IS THE COMPANY'S RELIABILITY PERFORMANCE RELATED TO UNDERINVESTMENT IN ITS DISTRIBUTION SYSTEM?

A. No. As explained further below, the Company's service territory presents many unique challenges to reliability. Despite that, the Company has made and continues to make the necessary upgrades to it distribution system to serve its customers and address the most prevalent outages causes on its system. Specifically, the Company has made a variety of distribution investments that are targeted at outages related to TIR, TOR, and equipment failures as explained further below. As shown in Figures EGP-6 through EGP-9, these programs have provided significant benefits to customers in terms of improved resiliency of the existing distribution grid, improved reliability for customers, and improved safety for the public and employees.

Furthermore, as explained further by Company Witness West, the Company invests more than any other investor-owned utility in the Commonwealth on a per customer basis. This, coupled with the reliability improvements that the Company has made over the last 10-plus years, demonstrates the Company is investing properly in its distribution system. However, the Company recognizes the need to complete additional scopes of work to address reliability concerns on its system, which is why the Company is proposing the DRR and its associated 5-year Work Plan.

VII. <u>OPERATING CHALLENGES</u>

Q. DESCRIBE THE OPERATING CHALLENGES THAT KENTUCKY POWER FACES.

A. **<u>Terrain</u>**: The Company's service territory consists of heavily forested and mountainous terrain that includes steep, rocky, heavily forested hill sides, and narrow valleys that constrains access to the transmission and distribution facilities. The difficulties this terrain creates in damage assessment, material and labor mobilization, and damage repairs increases customer outage restoration times.

Vegetation Density: Approximately 75% of Kentucky Power's overhead primary miles are exposed to vegetative risk and threat of interruption due to one or both TOR and TIR causes. Please see Exhibit EGP-2 for a map of the vegetation density in the Company's territory. The forests consist of mostly large, mature trees that experience natural tree mortalities that are compounded by invasive species of disease and insects, such as the Emerald Ash Borer. Since these trees are larger and heavier, when they do fall, they cause severe damage to the Company's distribution assets, such as broken poles, cross arms, and conductors.

Insects: Another contributor to the poor health of the trees outside of the ROW is the Emerald Ash Borer beetle. Kentucky is home to more than 220 million ash trees.[1] When a tree becomes infested with the Emerald Ash Borer, it dies within a few years, which makes it much more vulnerable to falling or being blown over into the Company's facilities and causing customer outages. While Emerald Ash Borer activity peaked in the Company's territory about 2.5 years ago, and is somewhat diminishing now, the effects of the devastation are still being felt as the trees destroyed by the insects, both TIR and TOR, are dead and dying.

Major Storm Events: Kentucky Power experienced 11 Major Storm Events (defined above) between January 11, 2020, and April 1, 2023. These Major Events included high windstorms, thunderstorms, straight-line windstorms, ice and snowstorms, and

[1] https://entomology.ca.uky.edu/entfact/kentucky-emerald-ash-borer-eab-resources-updates

rainstorms that caused mudslides and/or flooding. For more detail and descriptions of the Major Storm Events, please see the testimony of Company Witness Blankenship.

<u>Rainfall</u>: Average rainfall for the past several years has increased from the 30-year average. The increased rainfall contributes to the spread of insects, forest pathogens, and root disease affecting trees. The rainfall also loosens the soil. All together the increased effects of increased rainfall destabilizes the root structures, making the trees more susceptible to failure due to the associated increases in wind speeds. This has led to an increase in outages caused by TOR. As shown in Exhibit EGP-3, precipitation data from the National Weather Service for Jackson, Kentucky for the years of 1981 to 2010 shows a monthly average rainfall of 4.03 inches per month, or an annual average of 48.34 inches of rainfall. By contrast, the average annual precipitation for the most recent five-year period (2018-2022) was 59.13 inches, a 22.3% increase.

<u>Wind</u>: Over the last several years, Kentucky Power has experienced an increase in the number of Weather Alert Events which has caused an increase in the number of customer outages. Windstorms that produce wind gusts of at least 40 mph and other weather events that include wind are included in these weather alerts. Additional details on Weather Alert Events, windstorms and weather events are described in Company Witness Blankenship's testimony.

<u>Operational-Long circuits lengths, 34.5 kV circuits</u>: Due to the rural nature of the Company's service territory, the Company has long circuit lines and fewer customers per mile of primary distribution than other Kentucky investor-owned utilities ("IOU"). For example, the Company has approximately 16 customers per distribution line mile. This is significantly lower than our IOU peers in Kentucky that vary from between 34 and 65 customers per distribution line mile. This results in more exposure per mile per customer served for Kentucky Power, and greater potential for outage per customer with the additional exposure. This translates to potentially more customers interrupted and an increase in customer minutes of interruption. Additionally, primary voltage differences between stations and/or circuits (12.47 kV vs. 34.5 kV), generally has limited transfer load capability due to capacity of step-up or step-down transformers feeding the normal open points or connection points. There is also the potential for greater scheduled outages, especially where work is inaccessible to bucket trucks. Kentucky Power operates 39 circuits that have no three-phase connection to another circuit. When customers on these circuits experience an outage, they must wait for the circuit to be restored because the circuits do not have an alternative power source.

Q. PLEASE SUMMARIZE THE PRIMARY CAUSES OF OUTAGES IN KENTUCKY POWER'S SERVICE TERRITORY.

A. Figure EGP-5 summarizes the primary causes of customer outages and shows that vegetation outside of the ROW and equipment failures are the two leading causes of service interruption. Together these outage types account for 68% of CMI. Vegetation outside ROW, or TOR, accounts for 46% of total CMI and distribution equipment failures account for 22%. Moreover, TOR outages represent approximately 36,499,258 customer minutes interrupted out of approximately 79,488,727 total customer minutes interrupted for 2022.

Figure EGP-5 Major Outage Causes

Major Outage Causes - 2018-2022 CMI						
Outage Cause	**2018**	**2019**	**2020**	**2021**	**2022**	**% of Total 2022 CMI**
Trees Outside the ROW	36,151,502	41,010,994	30,255,212	30,474,613	36,499,258	46%
Equipment Failures	13,894,662	12,269,660	14,375,575	11,802,883	17,644,837	22%
Scheduled Company	10,847,405	9,713,420	4,442,381	7,103,757	5,665,724	7%
All Other Outage Causes	19,026,795	16,564,391	16,527,505	16,575,061	19,678,908	25%
Total CMI	79,920,364	79,558,465	65,600,673	65,956,314	79,488,727	100%

While the Company prudently invests in and maintains all distribution equipment, equipment failures eventually occur. These failures occur for a variety of reasons including equipment in service beyond manufacturer's useful life, stress as a result of conditions, and material or manufacturer defects caused by storms, vegetation, or vehicle accidents. Two primary examples of distribution equipment failures negatively impacting reliability are failures of insulators and cutouts. The outages caused by these equipment failures represent approximately 37% of total CMI for the 2022 distribution equipment failures. Insulator failures account for approximately 4,600,384 CMI and cutouts represent approximately 1,849,019 CMI out of a total of 79,488,727 CMI for 2022. Additional details regarding specific reasons for the equipment failures can be found later in my testimony in Section IX- the DRR section.

The All-Other category, which in sum totals approximately 25% of the total CMI, consists of a number of causes including: weather-related, trees inside the ROW, vehicle accidents, animals, ice, unknown causes, vandalism, etc.

VIII. DISTRIBUTION RELIABILITY PROGRAMS

Q. DOES KENTUCKY POWER CURRENTLY HAVE SPECIFIC PROGRAMS AIMED AT MAINTAINING AND IMPROVING THE RELIABILITY OF ITS SYSTEM?

A. Yes. Kentucky Power currently uses a combination of programs to maintain reliability on its distribution infrastructure. These programs are designed to reduce the number of service interruptions and to minimize their impact on customers. The Company's distribution management programs can be divided into three major categories:

1) Distribution Asset Management.

2) Major Distribution Reliability and Capacity Additions; and

3) Kentucky Power's Distribution Vegetation Management Program.

1) Distribution Asset Management

Q. PLEASE DESCRIBE KENTUCKY POWER'S DISTRIBUTION ASSET MANAGEMENT PROGRAMS.

A. The Distribution Asset Management Programs are designed to maximize the efficiency of expenditures and optimize system performance. The programs and their distribution system roles are:

1. Overhead Circuit and Underground Facilities Inspection and Maintenance Program: Every two years Kentucky Power visually inspects its overhead and the external, above-ground portions of underground distribution underground facilities to identify and correct potential problems before they can lead to an outage or cause a hazardous situation for the public. Through identifying and repairing such

potential problems, Kentucky Power's customers experience safer service with fewer service interruptions.

2. Capacitor and Regulator Inspection and Maintenance Program: The purpose of this program is to inspect and maintain all fixed and switched capacitor and regulator installations to ensure these devices function properly. Capacitor and regulator installations provide voltage support throughout the Kentucky Power service territory and are a critical component in the implementation of Volt/VAR Optimization, which improves the energy efficiency of the Company's distribution system.

3. Recloser Maintenance / Replacement Program: The Company performs preventive maintenance on reclosers, and replaces, as needed, recloser units that are not operating properly. When a recloser device senses a fault, the device will automatically open and allow a brief period for the cause of the fault to clear from the line. The reclosing equipment will then automatically re-energize the circuit. A recloser that does not open and close properly can turn a momentary interruption into a sustained interruption of service or result in an interruption to more customers than necessary.

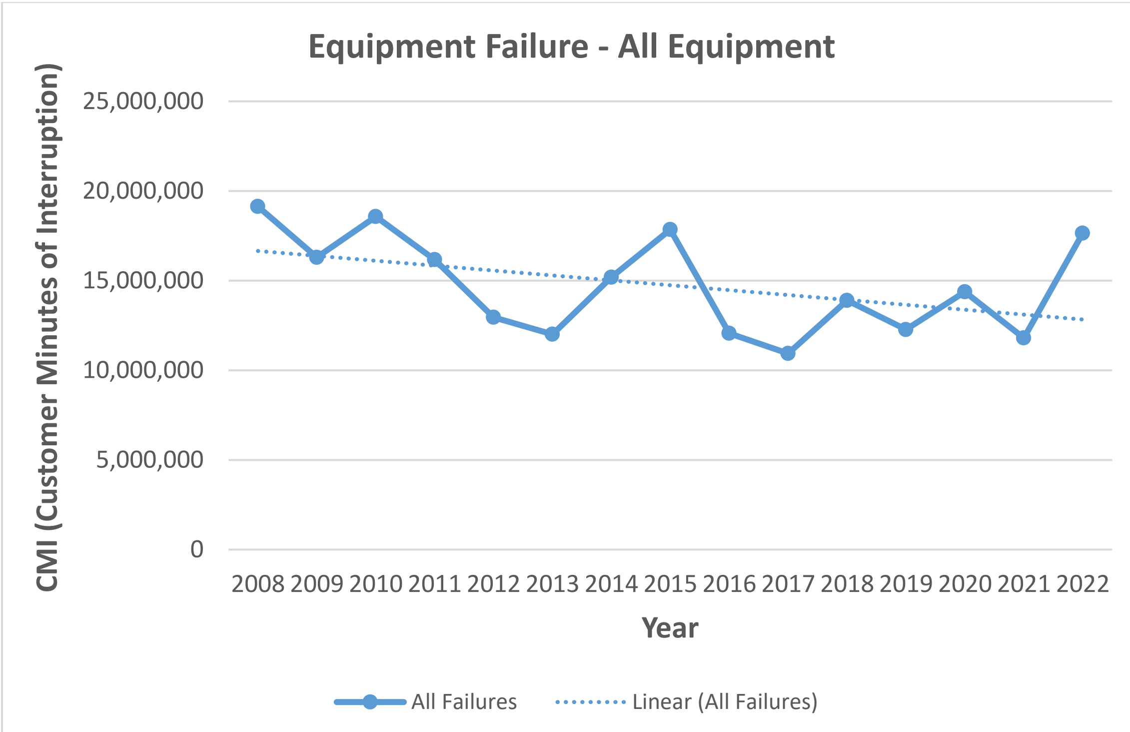
4. Overhead Conductor Program: This program minimizes primary and secondary conductor failures by replacing overhead conductors that show signs of wear. Targeted areas are identified using historical reliability data, and also include areas with an above average number of splices identified through the overhead facilities inspection program.

5. Sectionalizing Program: This program improves the reliability of Kentucky Power's distribution circuits by adding new, or modifying existing, sectionalizing devices. These sectionalizing devices may be manual pole top switches, automatic devices such as reclosers, automatic switches, or fused cutouts. The addition of manual switches where warranted allows the outage duration to be lessened for the customers served by the unaffected portions of the circuit that can be re-energized. Fused cutouts or reclosers work to remove a faulted section of the circuit from service and prevent the entire circuit from experiencing a sustained outage. This enhanced sectionalizing capability results in smaller circuit segments and fewer customers being interrupted after faults occur on distribution circuits.

Q. PLEASE PROVIDE DETAILS ON THE RELIABILITY BENEFITS THAT THE COMPANY'S CUSTOMERS RECEIVE THROUGH EXECUTION OF THESE PROGRAMS?

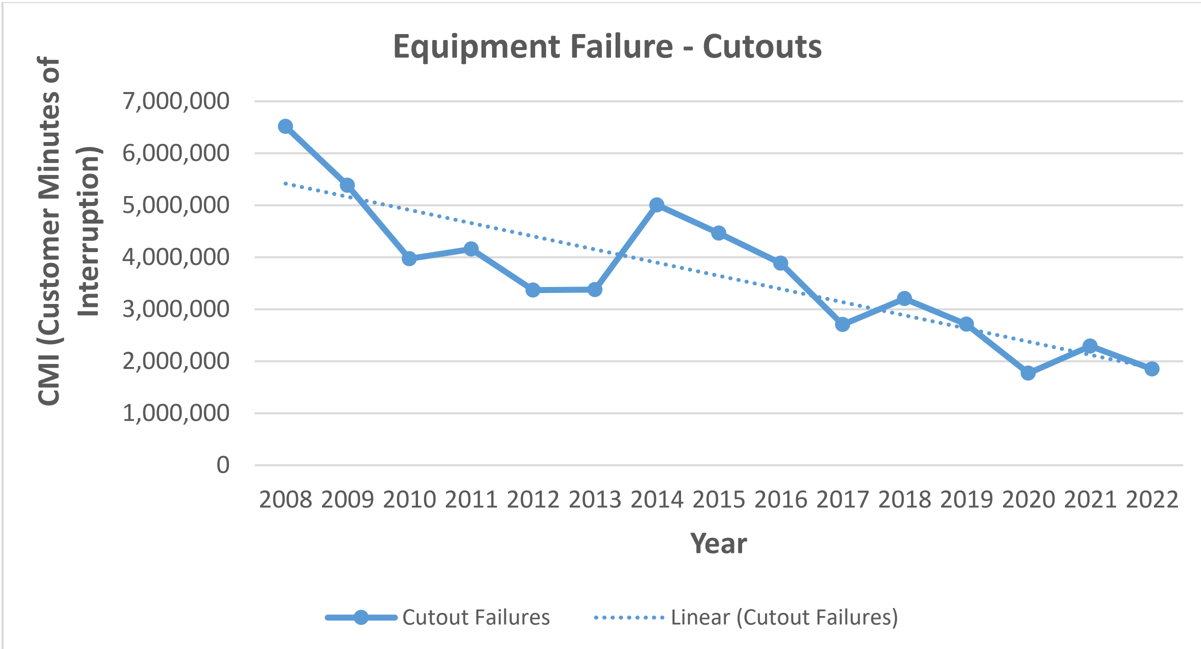
A. As shown by the trendline in Figure EGP-6, weather events in 2022 aside, equipment failures since 2008 have generally been trending downward. As shown in Figure EGP-6, Kentucky Power's customers have generally experienced a reduction in CMI caused by equipment failures.

Figure EGP-6 Trendline of Equipment Failure-All Equipment



The Company actively monitors equipment failures by reviewing historical outage data. Monitoring equipment failures at this level allows the Company to target its efforts towards mitigating outages related to specific equipment to improve overall reliability for Kentucky Power customers. For example, over the past 15 years (2008-2022) cutouts were the leading cause of equipment failures. By reviewing the historical outage data, and determining the leading causes of equipment failures, the Company has targeted cutouts resulting in a reduction in CMI of 72%, as illustrated in Figure EGP-7.

Figure EGP-7 Trendline of Equipment Failure-Cutouts



Insulator failures has been the second leading cause of equipment failure related CMI across the Company's distribution system during the past 15 years. However, in 2022 insulator failures were the leading cause of equipment failure-related outages and contributed 4,600,384 CMI in 2022. Similar to the actions taken to address cutout outages, the Company will address equipment outages for insulator failures through its DRR, which is described further below.

2) Major Distribution Reliability and Capacity Additions

Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE MAJOR DISTRIBUTION RELIABILITY AND CAPACITY ADDITIONS PROGRAM.

A. Each year, the Company undertakes various major distribution reliability improvements in addition to those included in the Asset Management Programs described previously. The improvements range from the simple construction of new distribution feeder ties to the complex additions of new substations with new distribution feeders to better serve our customers.

The Company's proactive planning efforts identify areas where the expected demand for electricity is approaching the limit of the distribution system's current capacity. The reliability improvement projects are necessary to serve load growth and upgrade, improve, or effectively maintain the Company's distribution system. These projects either re-conductor the existing feeders or allow portions of the existing distribution system to be reconfigured. The expansion of the distribution system to serve new customers can also result in the upgrade or replacement of distribution facilities to maintain and enhance reliable service to the Company's customers.

3) Kentucky Power's Distribution Vegetation Management Program

Q. PLEASE PROVIDE A SUMMARY OF KENTUCKY POWER'S VEGETATION MANAGEMENT PROGRAM.

A. Systematic, whole system vegetation management programs are widely utilized by the utility industry as an effective way to reduce the frequency and duration of vegetation related outages. Kentucky Power's Vegetation Management Program includes two major components for: (1) trees inside the ROW ("TIR"), a five-year cycle-based program, and (2) trees outside the ROW, identifying and removing danger trees and enhancing the ROW.

1. Distribution Vegetation Management Program-TIR

The TIR program is a cycle-based maintenance program that completes vegetation clearing and inspection of all distribution circuit ROW once every five years. The Company began the current five-year cycle-based Vegetation Management Program January 1, 2019. Activities associated with the program include inspections, customer communications, brush removal, trimming of trees, tree removals, certain herbicide applications, and post-clearing audits and inspections. The Company's Forestry Staff facilitate coordination and review of these tasks. All other functions are executed by contracted third parties working on behalf of Kentucky Power.

The Company is in the fifth year of the current five-year cycle and is approximately 60 miles ahead of target. Specifically, Kentucky Power targeted 1,623 miles for annual cycle maintenance and completed on average for the past four years, 1,638 miles per year. As shown later in this section, since the Company started focusing on TIR in June of 2010 and began implementing the five-year cycle maintenance, Customer Interruptions and CMI have decreased substantially over that period.

2. <u>Distribution Vegetation Management Program-TOR</u>

Vegetation, particularly trees outside ROW, remains the principal cause of outages in Kentucky Power's service territory. Kentucky Power's service territory is heavily forested and largely rural with difficult-to-access distribution equipment.

These terrain characteristics present unique accessibility and operational challenges that must be taken into consideration when planning distribution system maintenance. In the Company's 2018 Vegetation Management Plan, Kentucky Power established a program to widen the Company's existing ROW to address outside of the ROW causes of outages, including the removal of danger trees from outside the ROW. The Company began the program on a provisional pilot basis in the Company's Hazard District.

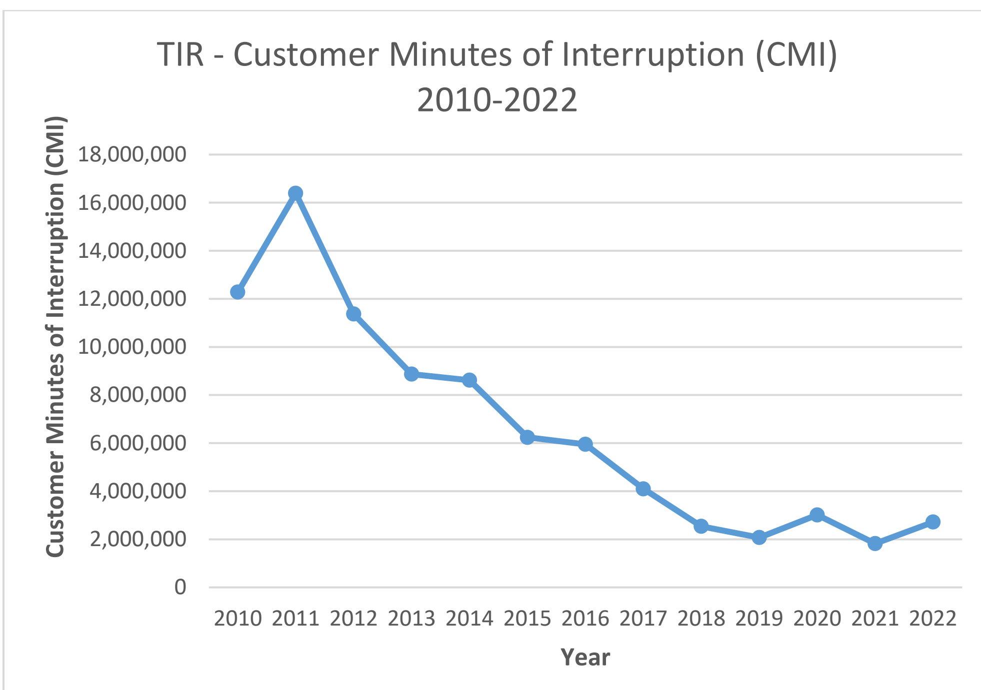
Based on the success in the Hazard and Pikeville Districts (the results of which are discussed later in this testimony), Kentucky Power is asking for an enhancement of the program. The Company is planning to extend it to additional circuits, as well as to go further into the circuits where widening has occurred as part of the proposed DRR.

Q. DOES THE TIR VEGETATION MANAGEMENT PROGRAM PROVIDE IMPROVED RELIABILITY FOR THE COMPANY'S CUSTOMERS?

A. Yes. The TIR program focuses on re-clearing and maintaining the Company's ROWs. As a result, one of the best measures of its effectiveness is CMI associated with trees and vines within the Company's ROWs.

As shown in Figure EGP-8, customer minutes interrupted as a result of trees and vines in the ROW, which measure the total impact of the interruptions, declined from 16,388,594 minutes in 2011 to 2,719,179 minutes in the year ended December 31, 2022. That represents an approximately 83% improvement between 2011 and 2022.

Figure EGP-8 – TIR CMI Reduction Trend



TIR interruptions are expected to remain mostly unchanged for the following reasons:

- The Company has completed end-to-end maintenance clearing for the entire primary distribution system and maintains control of its ROW.
- Refusals of customers to allow the Company to clear ROW to the Company's vegetation specifications are not expected to decline; and
- Outages on secondary distribution lines constitute a greater portion of the remaining total outages, limiting a reduction in the total number of outages beyond the current numbers. The Company's distribution vegetation management work has less effect on secondary distribution lines because secondary lines, including service to home attachments, are positioned lower on the poles and are subject to interference from customer planted trees and tall shrubs that become overgrown.

The trend over a ten-year period, as shown in Figure EGP-8 clearly shows the success the Company and its customers are experiencing from the investment in distribution vegetation management. In order to maintain this success, the Company must continue to invest in this cycle-based vegetation management approach. Due to the significant reliability improvements made by lowering CMI related to TIR outages, it is important and prudent to continue current funding levels and implementation to ensure the continued success of the program. Any reduction in the program levels can possibly cause an uptick in the results and require more dollars to bring the issues back under control.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE ONE-WAY BALANCING MECHANISM ASSOCIATED WITH THE COMPANY'S VEGETATION MANAGEMENT – TIR PROGRAM?

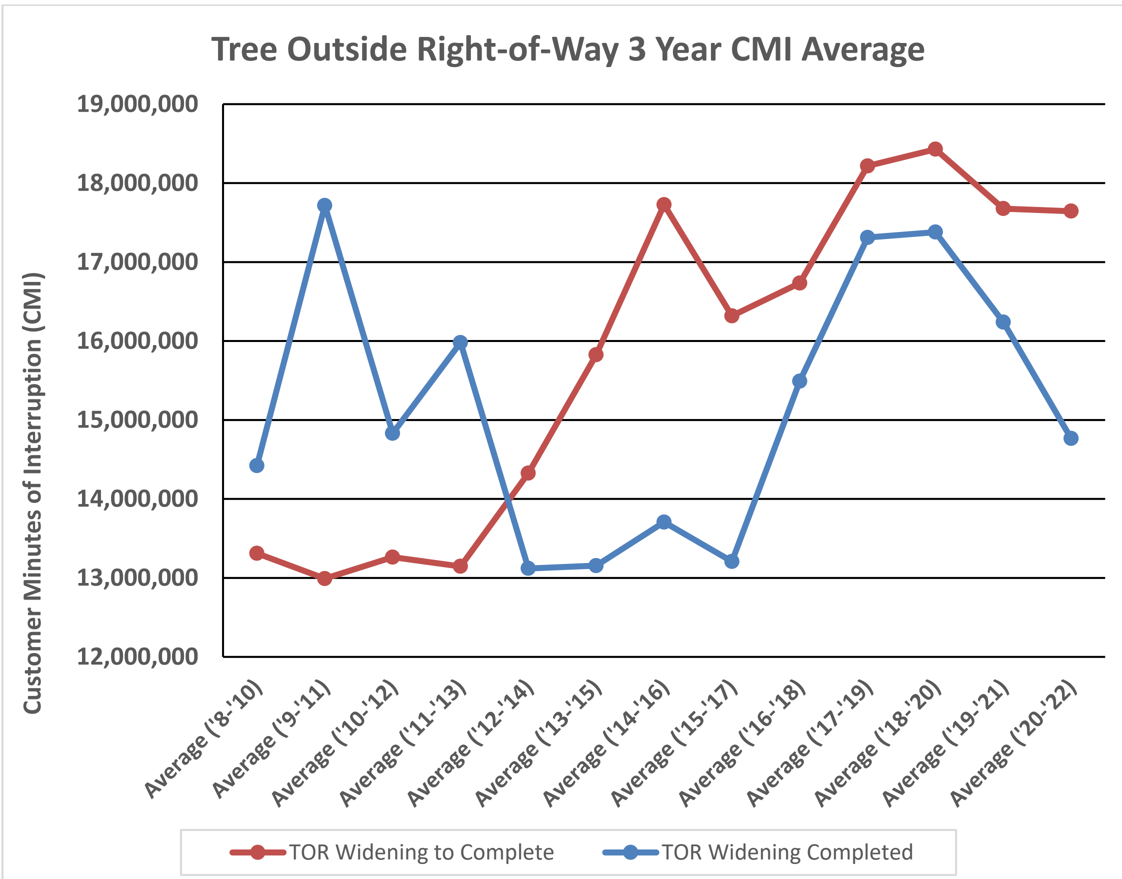
A. No. The Commission established the one-way balancing mechanism in its June 22, 2015 Order approving the Settlement Agreement in Case No. 2014-00396. In Case Nos. 2017-00179 and 2020-00174, the Commission found that the one-way balancing adjustments should be continued, with an adjustment based upon the change in the vegetation management program's annual revenue requirement approved in those cases. All expenses are recorded against each year's annual budget. Any annual shortfall or excess is applied to the balancing account. The Company proposes to continue the balancing account until further order of the Commission. The Company is proposing that actual test year Vegetation Management Program O&M expense of $22.4 million, as shown on Application Section V, Exhibit 2 W43, be established as the annual budget for the one-way balancing mechanism resulting from this proceeding.

Q. DOES THE TOR VEGETATION MANAGEMENT PROGRAM PROVIDE IMPROVED RELIABILITY FOR THE COMPANY'S CUSTOMERS?

A. Yes. In 2018, Kentucky Power initiated a pilot program to address the threat presented by trees outside its rights-of-way. At the end of 2022, the Company had completed portions of targeted widening on 65 of the 233 distribution circuits, or 28% of the Company's distribution circuits. This targeted approach represents approximately 6.6% of the Company's overhead primary distribution miles. To normalize outlier weather event years, the Company reviews a rolling three-year average of data for

TOR. Figure EGP-9 demonstrates there was a 15% reduction in SAIDI for average CMI 2018 through 2020 versus the average 2020 through 2022 for those circuits where some widening has occurred versus those circuits remaining to be completed has remained relatively flat.

Figure EGP-9 Three Year Average of TOR vs. CMI (2008-2022)



As shown in Figure EGP-9, circuits where the Company performed ROW widening to address TOR experienced a decrease in CMI as compared to those circuits that were not widened. In order to maintain and expand this success to all customers, the Company proposes to continue and expand in its TOR enhanced ROW widening program through the DRR.

IX. DISTRIBUTION RELIABILITY RIDER

Q. WHAT IS THE COMPANY'S LONG-TERM STRATEGY TO ADDRESS THE CHALLENGES IT FACES AND IMPROVE RELIABILITY?

A. As discussed above, the Company's distribution system faces numerous challenges. These challenges pose an immediate threat, and in fact have been major contributors to the Company's reliability performance. These operating challenges translate into customer outages, as highlighted in Figure EGP-5. Recent data shows that vegetation outside of the ROW and equipment failures are the two leading causes of service interruption.

In order for the Company to reverse these trends and improve reliability, the Company has developed a three-pronged strategy, as described in the DRR Work Plan, and shown in Exhibit EGP-4. The DRR Work Plan will initially focus on the two leading outages causes in order to improve reliability for customers.

As noted above, TOR was identified as the single largest cause of CMI. To address this, in 2018 the Company implemented a provisional pilot program through widening ROW. This approach has shown success in addressing TOR and improving reliability for customers. Therefore, as the first part of the Company's strategy, the DRR Work Plan would expand the Company's efforts to take the enhanced ROW widening approach and achieve similar reliability improvements the Company has seen through its provisional pilot.

The second part of the strategy is to add additional opportunities for transferring customers when a fault occurs. These include programs such as additional tie-lines, additional substation sources, Distribution Automation Circuit Reconfiguration ("DACR") and recloser modernization.

The final part is asset renewal. Under asset renewal, the Company will monitor and track specific defective equipment to determine if there is a tie to a manufacture or year make or model and upgrade the equipment. Examples of this process are cutouts and insulators. As a result of the Company's inspection program, Kentucky Power noticed cracking of the porcelain cutouts (there were multiple manufacturers for cutouts) over a span of time. The issues were occurring where the bonding agent to the mounting assembly of the porcelain or the porcelain was cracking. The Company noticed that when significant freezing and thawing occurred the following year the Company would see increased failures, especially after rain. Not all issues of cutouts are visibly noticeable from the ground and the Company began targeting a program to replace porcelain cutouts. As explained earlier, Figure EGP-7 demonstrates the CMI improvement trendline for cutouts.

In addition, the Company has identified that on certain models of epoxilators (insulators), used on 34.5 kV, over time, damage has occurred from UV rays. As the damage to the equipment occurs, the epoxilators are more noticeable from the ground. The Company plans to include this equipment in the next 2-year circuit inspection cycle and will identify and replace equipment where noticeable from ground. The asset renewal program identified in the DRR Work Plan will position the Company to be more readily able to invest proactively and reduce customer minutes of interruption from defective equipment.

Once these DRR programs have been fully implemented over the next several years and reliability has improved, the Company can then begin the next phase of its long-term strategy through the DRR and continue upgrading its system from medium loading to heavy loading. Please see Company Witness Blankenship's testimony for additional detail about the Company's strategy to increase the level of "heavy loading" of the Company's facilities. Company Witness West explains the details of how the DRR cost recovery mechanism will function, including how costs incurred in support of DRR programs will be tracked and transparently presented to the Commission and Staff for review on an annual basis.

Q. PLEASE DESCRIBE THE FOUR EQUIPMENT-RELATED PROGRAMS INCLUDED IN THE DRR WORK PLAN.

A. The Company has performed a review of reliability information to help develop the Company's proposed initial DRR programs. Specifically, the Company reviewed historical outage types and impacts associated with those outages. This information helped the Company develop the proposed DRR programs, which are designed to target the outage causes responsible for the greatest number of customer minutes of interruption. The DRR programs will provide for investment in:

<u>Additional Distribution Assets</u>

The Company is proposing adding additional assets to improve operational efficiencies that reduce customer minutes of interruption. The specific programs include:

- Additional Tie Lines – Construct primary lines to tie two circuits together, permitting electrical load to be transferred between the two circuits. This will reduce the number of radial circuits.

- DACR/Recloser Modernization –
    - DACR – Install automation equipment on distribution circuits allowing isolation of a fault; and reconfigures a circuit to close other devices to re-energize the non-impacted areas of original circuit impacted by initial fault.
    - Recloser Modernization – Upgrade the recloser devices to operate as single-phase devices instead of 3-phase. However, they will remain in the 3-phase circuit. Upgrade existing reclosing devices to electronically controlled devices. These devices will allow for more precise coordination with other devices, provide event recordings for outage and power quality investigations, and enable future DACR implementation. These devices will also allow for single phase operation in 3-phase circuits to keep customers from other phases energized when there are single phase outages on 3-phase devices.
- Additional New Distribution Substation Sources – The Company will construct new distribution substations with associated transmission lines in and out of the substation. This will include construction of distribution lines to tie into existing distribution circuits. Each new substation will require a minimum of two to three years to place in service due to long lead times on station equipment. When outages occur, the new substations will allow the Company to restore power faster when the system has capacity to shift load to adjacent circuits. The new substations with this additional pathway of new circuits are intended to reduce outage durations for customers.

Distribution Asset Renewal

- Asset Renewal and Resiliency – This is a feeder renewal and hardening program that will renew and improve the feeder and enable overhead mainline facilities to better withstand major and non-major weather events. Under this program, Kentucky Power will select targeted facilities projects to renew and improve cable, conductor, hardware and equipment that will reduce the risk of feeder-level outages. This improvement will include strengthening structures by replacing to a higher design standard, upgrading conductors, and relocating difficult to access facilities. The Resiliency and Grid Hardening program is comprised of replacing cutouts, arrestors, cross-arms, overhead hardware, and underground service equipment rehabilitation. In addition, the Company will evaluate aging infrastructure to replace with equipment designed for heavy loading criteria to better protect against extreme weather, (*e.g.* replace poles and conductors to withstand up to one half inch of ice). This will ruggedize the system and accommodate greater system capacity for additional load carrying capability and transferability. The Company will also use this program to replace certain types of equipment that are leading to high levels of outage, such as insulators.

Q. WHAT ARE THE COSTS ASSOCIATED WITH THE PROPOSED DRR?

A. The DRR is the proposed mechanism by which the Company will recover the eligible costs associated with DRR projects that are proposed in the DRR Work Plan. Figure EGP-10 below shows the estimated capital and O&M costs for the proposed DRR

Work Plan from 2024 through 2028.

Figure EGP-10 Estimated DRR Capital and O&M Expenditures

DRR Component	Projected 2024 Spend	Projected 2025 Spend	Projected 2026 Spend	Projected 2027 Spend	Projected 2028 Spend
CAPITAL					
TOR – Enhanced ROW Widening	$12,000,000	$12,000,000	$12,000,000	$12,000,000	$12,000,000
Additional Tie Lines	$1,000,000	$3,300,000	$3,200,000	$1,500,000	$1,600,000
DACR/Recloser Modernization	$1,000,000	$4,000,000	$8,900,000	$0	$13,900,000
Additional New Distribution Substation Sources	$3,000,000	$12,000,000	$4,800,000	$22,600,000	$10,100,000
Asset Renewal/ Storm Hardening or Resiliency	$2,000,000	$4,000,000	$4,000,000	$2,700,000	$2,400,000
Totals	**$19,000,000**	**$35,300,000**	**$32,900,000**	**$38,800,000**	**$40,000,000**
O&M					
TOR – Enhanced ROW Widening	$0	$0	$0	$0	$0
Additional Tie Lines	$100,000	$300,000	$300,000	$200,000	$200,000
DACR/Recloser Modernization	$100,000	$200,000	$400,000	$0	$700,000
Additional New Distribution Substation Sources	$0	$0	$0	$0	$0
Asset Renewal/ Storm Hardening or Resiliency	$200,000	$400,000	$400,000	$300,000	$200,000
Totals	**$400,000**	**$900,000**	**$1,100,000**	**$500,000**	**$1,100,000**

Q. WHAT CUSTOMER BENEFITS WILL THE DRR PRODUCE?

A. The DRR will provide many benefits for customers, including the following:

- Improved resiliency of the existing distribution grid;
- Improved reliability for customers; and

- Improved safety for the public and employees.

As shown in Figure EGP-11 the five programs that the Company plans to implement in the DRR are expected to provide reliability improvements as the capital improvements are implemented over the 2024-2028 timeframe.

Figure EGP-11 Expected Reliability Improvements 2024-2028

DRR Component	Equipment Affected	Measurement Units
TOR – Enhancing ROW Widening	Poles, conductor	Equipment replaced
Additional Tie Lines	Poles, conductor, regulators, switches	Tie lines completed
DACR /Recloser Modernization	Reclosers, telecommunication equipment including radios, antennas, distribution remote terminal units ("DRTU's")	DACR circuits put in-service
Additional New Distribution Substation Sources	Station transformers, circuit breakers, regulators	Distribution Sources added
Asset Renewal/ Storm Hardening or Resiliency	Poles, conductor	Equipment replaced
Total Projected SAIDI Minute Reduction by 12/31/29*	**56 minutes**	

*SAIDI (CMI) Savings potentially achieved the year following the capital investment installation.

Q. HOW WILL THE COMPANY REPORT ON THE DRR GOING FORWARD?

A. As explained further by Company Witness West, if approved, the Company will begin to implement the plan in 2024 and submit a filing for recovery of the investments. In addition, the Company will file a report, in a form similar to Exhibit EGP-4, which shows its performance in comparison to its plan for that year for the Commission to review. The Company suggests this report would be part of the Company's annually filed reliability report.

X. UPDATE ON SMART GRID INVESTMENTS

Q. PLEASE DESCRIBE "SMART GRID" INVESTMENTS.

A. Smart grid technology uses advanced information tools to improve the efficiency, reliability, and safety of the distribution system. In its April 13, 2016 order in Case No. 2012-00428, the Commission directed each utility in the Commonwealth subject to its jurisdiction to identify its Smart Grid investments in each rate case. The information provided in this section fulfills the Commission's directive.

Q. WHAT KINDS OF SMART GRID INVESTMENTS HAVE THE COMPANY MADE SINCE THE LAST BASE CASE?

A. Since the last base case, Kentucky Power has made $3,463,115 in Smart Grid investments in its distribution system. These investments allow for a series of automated actions that can reduce the impact and duration of an outage. If a fault occurs on a distribution line that has DACR, the DACR system will recognize the fault location, isolate that portion of line, and restore unaffected customers through other portions of DACR construction, all before a truck is dispatched to the scene. To facilitate these processes, Kentucky Power utilizes a Distribution Management System that includes Supervisory Control and Data Acquisition ("SCADA") to provide system analysis and remote control of the distribution system. The Data Management System gathers information from electronic devices in the field, including the DACR equipment, and integrates it with the mapping system to provide the real-time status of these automated circuits. It also allows remote operation of devices on those circuits by dispatchers if immediate intervention, maintenance, or load control is needed.

These Smart Grid investments provide customer benefits and an enhanced customer experience. For example, upgrades to some of the Smart Grid investments have improved DACR logic, which allows for more reliable and diversified automated reactions, as well as greater monitoring capabilities of the DACR scheme. As another example, the Company has made Smart Grid investments that include the construction of new station and line equipment in order to break up overhead line miles on already existing distribution circuits. Breaking up the overhead line miles facilitates redundancy for customers in the area and can improve reliability by providing an alternate source of power in the event of an outage. Ultimately, these types of Smart Grid investments reduce the frequency and duration of customer outages. For this reason, the Company looks for opportunities to incorporate Smart Grid investments into the construction of new distribution circuits.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Everett G. Phillips, being duly sworn, deposes and says he is the Vice President, Distribution Region Operations for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Everett G. Phillips

Everett G. Phillips

Commonwealth of Kentucky	)	
	)	Case No. 2023-00159
County of Boyd	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Everett G. Phillips, on June 22, 2023.

Scott E. Bishop

Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

Electric Distribution Service Areas

PSC Regulated Rural Electric Utilities

Members of East Kentucky Power Cooperative, Inc. (transmission cooperative)

- Big Sandy RECC
- Blue Grass Energy Cooperative
- Clark Energy Cooperative
- Cumberland Valley Electric
- Farmers RECC
- Fleming-Mason Energy Cooperative
- Grayson RECC
- Inter-County Energy Cooperative
- Jackson Energy Cooperative
- Licking Valley RECC
- Nolin RECC
- Owen Electric Cooperative
- Salt River Electric Cooperative
- Shelby Energy Cooperative
- South Kentucky RECC
- Taylor County RECC

Members of Big Rivers Electric Corporation (transmission cooperative)

- Jackson Purchase Energy
- Kenergy Corporation
- Meade County RECC

Municipal Utilities

Barbourville, Bardstown, Bardwell, Benham, Benton, Berea, Bowling Green, Corbin, Falmouth, Frankfort, Franklin, Fulton, Glasgow, Henderson, Hickman, Hopkinsville, Jellico (TN), Madisonville, Mayfield, Murray, Nicholasville, Olive Hill, Owensboro, Paducah, Paris, Princeton, Providence, Russellville, Vanceburg, Williamstown

PSC Regulated Investor Owned Utilities

- Duke Energy Kentucky, Inc.
- Kentucky Power Company
- Kentucky Utilities Company (KU)
- Louisville Gas and Electric Company (LG&E)

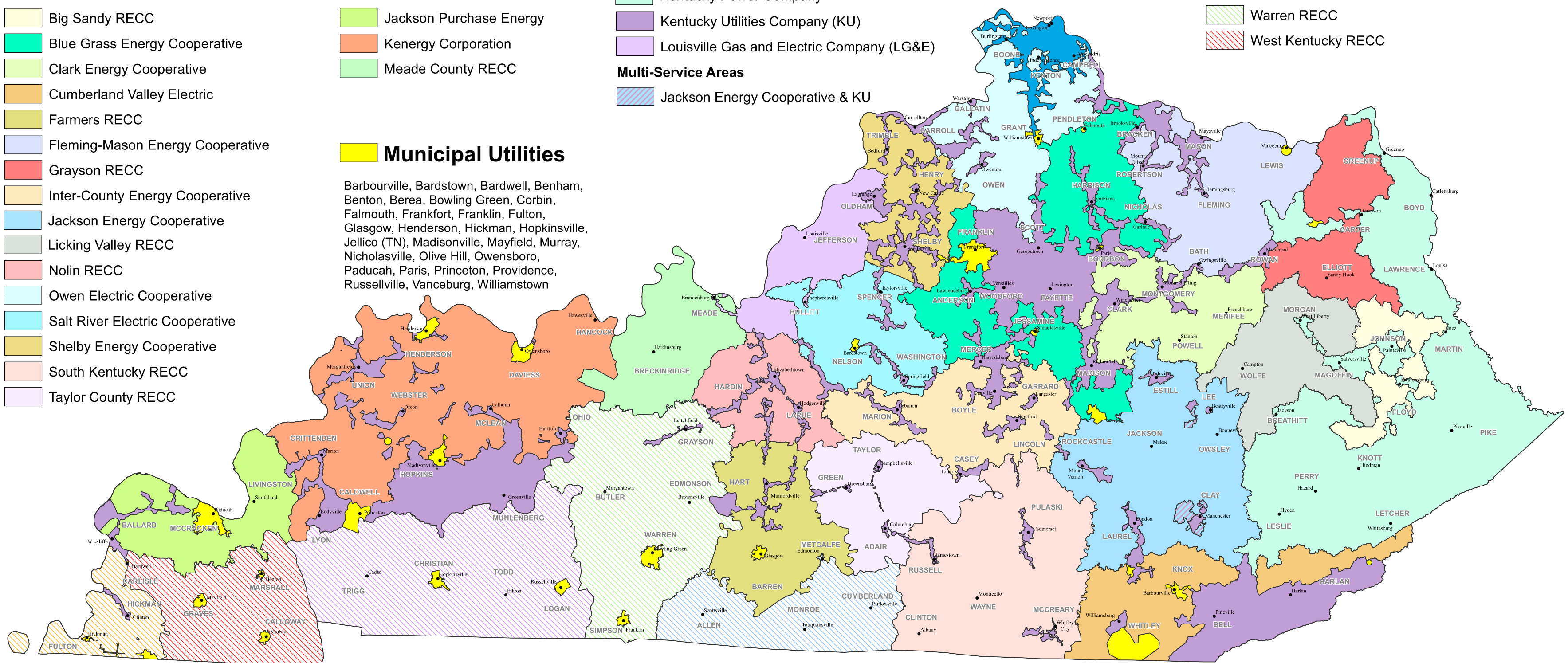
Multi-Service Areas

- Jackson Energy Cooperative & KU

- County Seats
- County Boundaries

TVA Regulated Utilities

- Gibson EMC (TN)
- Pennyrile RECC
- Tri-County REMC
- Warren RECC
- West Kentucky RECC



10 5 0 10 20 30 40 50 Miles

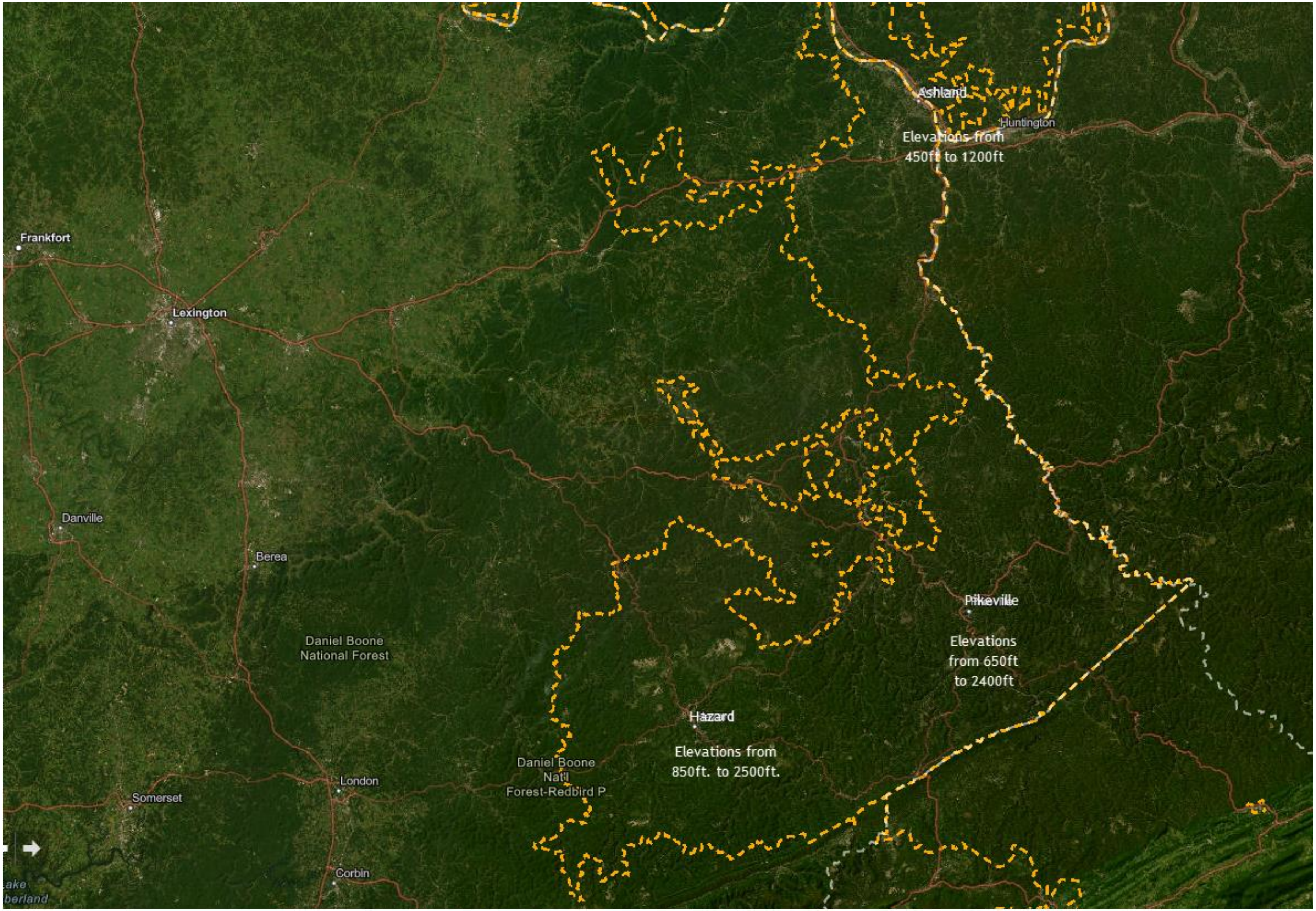
10 5 0 10 20 30 40 50 Kilometers

The electric service areas are compiled from certified territory maps on file with the Public Service Commission. These are legal documents which define the retail service area of electric suppliers regulated by the Commission (Kentucky Statute 278.017). The legal certified territory boundaries are drafted on 1:24,000 USGS topographic maps, and can be assumed to have an accuracy of 100 feet. This map, which was compiled from that data, is for informational purposes only, and has no legal standing.

Kentucky has 30 municipal systems serving over 500,000 customers. Ten of these are provided wholesale power by the Tennessee Valley Authority (TVA) and are regulated by them. The others are self-regulated by the municipality. The boundaries for the municipal systems were either derived from the Public Service Commission's certified territory maps, or from boundaries submitted for informational purposes to the PSC from the utility. If the municipal service area boundaries were unknown, a circle was placed around the urbanized area.

Kentucky Public Service Commission
March 17, 2023

Kentucky Power Vegetation Density/Service Territory



Recorded Data from National Weather Service for Jackson, KY

30 Yr Normal Precip (1981 - 2010) Jackson, KY Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Norm
	3.61	**3.75**	**4.12**	**3.83**	**5.20**	**4.70**	**4.65**	**3.69**	**3.46**	**3.19**	**3.96**	**4.18**	**48.34**

Monthly Total Inches Precipitation for Jackson, KY Area

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
2001	2.50	3.72	2.17	1.69	4.39	4.19	6.43	2.41	1.09	1.41	1.82	2.55	34.37
2002	4.09	1.24	7.96	4.11	5.23	4.98	5.50	1.72	3.48	6.39	3.61	4.28	52.59
2003	2.10	7.88	1.47	5.14	5.98	7.54	3.95	5.12	4.33	2.20	5.49	3.78	54.98
2004	4.23	3.77	3.87	4.01	10.78	6.18	7.02	2.39	7.55	4.96	4.37	3.27	62.40
2005	5.12	3.03	3.52	7.47	2.50	2.78	4.08	3.92	0.51	1.57	2.66	3.18	40.34
2006	5.57	1.85	2.89	4.57	3.61	3.24	3.87	3.69	6.39	5.49	2.43	2.03	45.63
2007	2.83	1.20	2.71	3.22	1.82	2.15	4.05	2.64	2.49	3.80	3.37	5.18	35.46
2008	2.46	3.41	4.14	4.00	3.24	3.94	6.13	1.16	0.67	1.46	3.03	6.86	40.50
2009	5.80	1.73	3.52	3.64	9.22	7.03	6.40	3.55	4.88	3.54	0.80	5.96	56.07
2010	4.27	3.11	2.43	2.61	7.92	5.60	3.34	3.51	2.05	1.68	5.77	2.97	45.26
2011	2.72	3.97	4.74	10.20	6.69	5.49	6.02	3.07	3.20	4.25	5.48	4.18	60.01
2012	4.86	3.90	4.07	2.67	4.20	1.91	7.39	4.75	6.77	4.24	0.84	6.39	51.99
2013	5.73	1.91	4.63	3.70	4.23	6.36	6.62	10.04	1.27	2.13	3.01	7.09	56.72
2014	3.15	4.47	5.51	5.43	2.30	3.12	5.77	8.55	2.35	7.77	2.97	2.49	53.88
2015	2.12	4.06	6.26	10.29	1.74	7.42	8.87	5.02	2.09	2.40	2.41	4.64	57.32
2016	3.29	6.27	2.38	3.82	7.04	5.01	6.35	6.83	1.32	1.51	2.91	6.16	52.89
2017	4.71	2.86	4.42	4.02	7.41	6.21	4.13	4.56	3.33	5.29	1.30	3.28	51.52
2018	1.92	8.00	6.97	4.12	6.18	4.63	5.06	4.43	9.17	5.12	4.91	7.47	67.98
2019	4.26	8.87	2.40	2.80	4.90	8.01	6.97	1.25	T	6.01	5.80	6.30	57.57
2020	3.37	7.12	9.42	4.69	4.98	5.38	5.45	6.21	3.78	3.19	2.94	4.91	61.44
2021	3.55	8.09	5.44	3.39	2.24	3.84	7.52	8.78	2.39	2.84	1.67	2.71	52.46
2022	7.71	5.61	2.21	3.60	6.51	3.43	14.86	3.65	1.31	0.83	2.81	3.69	56.22
2023	**4.26**	**5.14**	**4.09**										
20 Yr Mean (through Mar 2023)	4.10	4.42	4.28	4.67	5.17	4.96	6.19	4.66	3.47	3.51	3.25	4.63	53.03
3 Yr Mean ('20 - '22)	4.88	6.94	5.69	3.89	4.58	4.22	9.28	6.21	2.49	2.29	2.47	3.77	56.71
5 Yr Mean ('18 - '22)	4.16	7.54	5.29	3.72	4.96	5.06	7.97	4.86	4.16	3.60	3.63	5.02	59.13

DRR Component	Program Description	Measures for Reliability Improvements	Projected 2024 Capital Spend	Projected 2025 Capital Spend	Projected 2026 Capital Spend	Projected 2027 Capital Spend	Projected 2028 Capital Spend
TOR - Enhanced ROW Widening	Targeted widening generally 10' to 30' on the uphill side of facilities. Circuits targeted based on historical TOR SAIDI and forester field inspections.	Reduce number of customer minutes of interruption (CMI) for TOR outages	$12.0M	$12.0M	$12.0M	$12.0M	$12.0M
Additional Tie Lines	Construct primary lines to tie two circuits together, permitting electrical load to be transferred between the two circuits. This will reduce the number of radial circuits.	Reduce number of customers minutes of interruption (CMI)	$1.0M	$3.3M	$3.2M	$1.5M	$1.6M
DACR (Distribution Automation- Circuit Reconfiguration)/Recloser Modernization	DACR-Install automation equipment on distribution circuits allowing isolation of a fault; reconfigures a circuit to close other devices to re-energize the non-impacted areas of original circuit impacted by initial fault. Recloser- Upgrade the recloser devices to operate as single-phase devices instead of 3-phase. However, they will remain in the 3-phase circuit. This operational change will reduce customer minutes of interruption. Upgrade existing reclosing devices to electronically controlled devices. These devices will allow for more precise coordination with other devices, provide event recordings for outage and power quality investigations, and enable future DACR implementation. These devices will also allow for single phase operation in 3-phase circuits to keep customers from other phases energized when there are single phase outages on 3-phase devices.	Reduce number of customers minutes of interruption (CMI)	$1.0M	$4.0M	$8.9M	$0.0M	$13.9M
Additional New Distribution Substation Sources	Construct new distribution substations with associated transmission lines in and out of substation. Construct distribution lines to tie into existing distribution circuits. The new substations will be in remote areas, helping to reduce the number of radial distribution circuits. Each new substation will require a minimum of two years to place in-service due to long lead times on station equipment.	Reduce number of customers minutes of interruption (CMI)	$3.0M	$12.0M	$4.8M	$22.6M	$10.1M
Asset Renewal/ Storm Hardening or Resiliency	Replace aging or failing equipment such as cutouts and insulators, as well as replace aging infrastructure with equipment designed for NESC heavy loading criteria to better protect against extreme weather; *i.e.*: replace poles and conductors to withstand up to one half inch of ice.	Reduce number of customers minutes of interruption (CMI) and outage time	$2.0M	$4.0M	$4.0M	$2.7M	$2.4M
		Totals	**$19.0M**	**$35.3M**	**$32.9M**	**$38.8M**	**$40.0M**

NOTE: SAIDI (CMI) savings begins the year following when the Capital investment has been made, for example, SAIDI (CMI) savings would occur 2025 -2029. The Company projects **56 SAIDI** minutes saved at the completion of the proposed 5-year DRR Plan.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2023-00159
Regulatory Assets And Liabilities; (4) A	)	
Securitization Financing Order; And (5) All Other	)	
Required Approvals And Relief	)	

DIRECT TESTIMONY OF

STEPHEN D. BLANKENSHIP

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
STEPHEN D. BLANKENSHIP ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT SDB-1	Major Storm Event Cost Summary
EXHIBIT SDB-2	NESC Transfer Case Discovery

DIRECT TESTIMONY OF
STEPHEN D. BLANKENSHIP ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Stephen D. Blankenship. My business address is 12333 Kevin Avenue, Ashland, Kentucky 41102. I am the Region Support Manager for Kentucky Power Company ("Kentucky Power" or the "Company"). Kentucky Power Company is a subsidiary of American Electric Power Company, Inc. ("AEP").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a bachelor's degree in Industrial Relations in 1995 from the West Virginia Institute of Technology, and an associate degree in Electronics and Computer Engineering Technology in 2019 from Grantham University. Throughout my 25-year career, I have held positions of increasing responsibility within the AEP family of companies, which have focused primarily on distribution operations. I began my career in 1998 as a Customer Service Representative in Hurricane, WV for American Electric Power Service Corporation ("AEPSC"), a subsidiary of AEP. From 2002 to 2016, I held distribution dispatching positions of increasing responsibility in locations that included Ft. Wayne, Indiana; Columbus, Ohio; and Ashland, Kentucky. In 2016, I was promoted to Distribution Dispatch Supervisor for Kentucky Power. In

2019, I was promoted to Meter Revenue Operations Manager for Kentucky Power and in 2020, I was promoted to Region Support Manager.

Q. WHAT ARE YOUR RESPONSIBILITIES AS REGION SUPPORT MANAGER?

A. I am responsible for the Company's distribution system operations, meter operations and storm review coordination. My duties also include the management of the safe and reliable restoration of the Company's distribution facilities following disruptions, proper implementation of normal and emergency procedures, and overall real time operation of the Company's distribution system. I am also responsible for coordination of the Company's storm response and Planning Section of the Incident Command System ("ICS") when implemented.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before this Commission in Case No. 2020-00174 (the Company's last base rate case).

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the reasonable and necessary distribution-related operations and maintenance ("O&M") costs Kentucky Power incurred for system restoration following 11 Major Storm Events that occurred between January 2020 and April 2023. The Company is proposing to securitize these costs as part of this proceeding.

My testimony will also address the following:

- the increase in the number of Weather Alert Events in the Company's service territory, including Major Storm Events and their magnitude;

- Major Storm Events' impact on the Company's distribution and transmission systems;
- how the Company prepared and responded to these storms as it relates to distribution; and
- the reasonableness of the distribution- and transmission-related O&M expenses incurred for system restoration.

My testimony will also demonstrate that the Company's storm restoration costs related to the 11 Major Storm Events were prudently incurred, are reasonable, and are not a result of underinvestment in the Company's distribution system.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits attached to my testimony:

Exhibit	Description
EXHIBIT SDB-1	Major Storm Event Cost Summary
EXHIBIT SDB-2	NESC Transfer Case Discovery

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WHAT IS THE COMPANY'S PROPOSAL RELATED TO THE RECOVERY OF THE 11 MAJOR STORM EVENTS THAT OCCURRED BETWEEN JANUARY 2020 AND APRIL 2023?

A. As a component of the Company's overall securitization request in this case, the Company is proposing to securitize approximately $79.3 million of regulatory assets associated with 11 Major Storm Events that occurred across the Company's service territory between January 2020 and April 2023. Company Witness West further describes the Company's overall securitization request in this proceeding.

IV. KENTUCKY POWER SYSTEM AND THE INCREASING LEVEL OF STORMS AND STORM SEVERITY

Q. PLEASE DESCRIBE THE DISTRIBUTION AND TRANSMISSION SYSTEMS THAT SERVES KENTUCKY POWER'S CUSTOMERS.

A. Kentucky Power serves approximately 163,400 retail customers in Kentucky in a service area that covers approximately 3,787 square miles. Kentucky Power owns approximately 1,263 circuit miles of transmission lines. Kentucky Power's transmission system is designed and constructed to meet heavy loading criteria.

Kentucky Power's distribution system includes approximately 10,108 circuit miles of underground and above-ground primary and secondary voltage lines. Kentucky Power's distribution system is designed and constructed to meet medium loading criteria, with some portions designed and constructed to meet heavy loading. Kentucky Power's service territory includes some of the most rugged and difficult topography in the Commonwealth. Its distribution and lower voltage transmission facilities cross mountainous and heavily wooded terrain. Company Witness Phillips provides further information regarding the Company's service territory and the corresponding operational challenges.

Q. WHAT ARE MAJOR STORM EVENTS AND HOW ARE THEY DETERMINED?

A. IEEE 1366-2017, the "IEEE Guide for Electric Power Distribution Reliability Indices," defines a major event as "an event that exceeds reasonable design and or operational limits of the electric power system. A Major Storm Event includes at least one Major Event Day. A Major Event Day is defined as "a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purpose of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather)." The IEEE standard uses an accepted statistical approach to determine when it is appropriate to exclude a major event. By excluding major storm events, which by definition are storm events that exceed reasonable design or operational limits, the Company also is able to give the Commission a clearer picture of the progress being made to improve the Company's reliability.

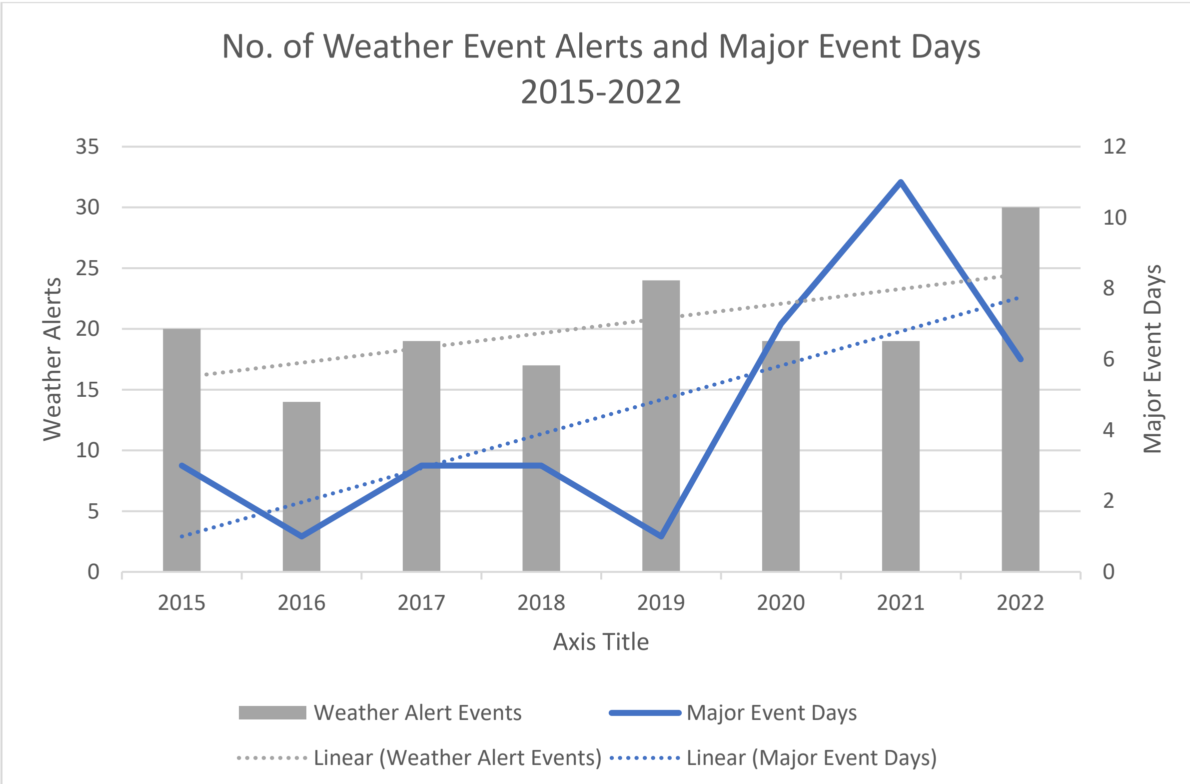
Q. WHAT ARE WEATHER ALERT EVENTS?

A. Weather Alert Events are predicted weather events which meet pre-defined thresholds that have been set by AEP's Meteorology department. These thresholds include ice storms that produce a quarter inch of ice or more, snowstorms that produce at least three inches of wet snow or six inches of dry snow, windstorms that produce wind gusts of at least 40 mph, and severe thunderstorms.

Q. HAS KENTUCKY POWER BEEN EXPERIENCING A GROWING NUMBER OF WEATHER ALERT EVENTS AS WELL AS MAJOR STORM EVENTS?

A. Yes. Figure SDB-1 shows that over the last several years, Kentucky Power has experienced an increase in the number of Weather Alert Events and Major Storm Events, which has caused an increase in the number of customer outages. Weather Alert Events can also include Major Storm Events.

Figure SDB-1



Although Figure SDB-1 indicates a decrease in the number of Major Storm Events between 2021 and 2022, as I describe in more detail below, this does not take into consideration the magnitude and severity of some of the Major Storm Events that the Company experienced in particularly in 2021 and 2022, but also in any other year.

Q. PLEASE ELABORATE ON THE MAGNITUDE AND SEVERITY OF WEATHER ALERT EVENTS OVER THE PERIOD AT ISSUE.

A. Weather Alert Events and Major Storm Events have been increasing in magnitude and severity over the last three years. Below are three examples of recent severe Major Storm Events impacting the Company's service territory:

- April 12, 2020 Straight-Line Wind Storm – This storm, also known as a "gravity wave," produced winds of more than 40 mph and gusted as high as 79 mph near

Dorton, Kentucky. A gravity wave is a meteorological phenomenon where strong winds of one to two hours' duration occur along with a rapid fall and rise in surface pressure.[1] Several other gusts of 40+ mph occurred, leading to numerous instances of damage across eastern Kentucky, including downed trees, power lines, and structural damage. This damage resulted in several roadways being blocked for a period of time into the morning of April 13, 2020. As many as 70,000 to 75,000 power outages were reported across eastern Kentucky.

- February 2021 Ice and Snow Storms – This event included three storms that resulted in about one inch of ice and four to six inches of snow in the worst-hit areas of the Company's service territory. Many roads became impassable due to downed trees and electrical lines, as well as ice and snow. In total, 110,365 customers were impacted by this event. These storms were so severe and destructive, Governor Beshear declared a State of Emergency across Kentucky on February 11, 2021.
- July 28, 2022 Historic Flood Event – This event was a historic 1,000-year probability flooding event that included heavy rain, deadly flash flooding, mudslides, and landslides. Flash flooding presents the most dangerous kinds of floods as it combines destructive power with incredible speed. There were times during this event that rainfall rates exceeded four inches an hour, with an estimated 14-16 inches of rainfall during the five-day event. Restoration crews faced serious access issues as some roads and bridges were entirely washed away, flooded, or blocked by debris. Governor Beshear declared a State of Emergency

[1] https://www.weather.gov/jkl/041220_Gravity_Wave (last accessed June 16, 2023).

across Kentucky on July 28, 2022. The event led to 39 deaths and widespread catastrophic damage.

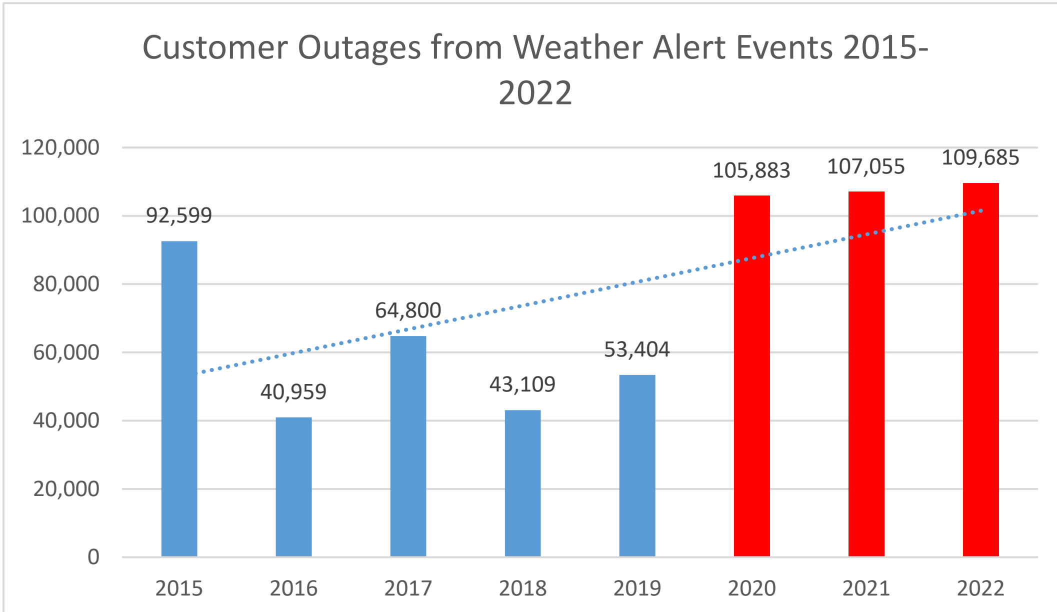
These Major Storm Events, as well as others that the Company has recently experienced, are discussed in more detail later in my testimony.

Another indicator of the increase in number and severity of Major Storm Events is demonstrated by the number of requests the Company has made to establish regulatory assets related to the extraordinary expenses resulting from restoring customer service following these events. The Company has had to make six such filings related to 11 Major Storm Events since 2020. From 2009 until 2020, the Company had to make only three filings (Case Nos. 2009-00352, 2012-00445, and 2016-00180). The average deferral amount for each of the 11 Major Storm Events that occurred from 2020 through 2023 is approximately $7.2 million, whereas the average deferral amount for each of the nine Major Storm Events that occurred between 2009 and 2016 was approximately $3.0 million.

Q. HAVE THESE WEATHER ALERT EVENTS CONTRIBUTED TO AN INCREASE IN CUSTOMER OUTAGES?

A. Yes. These increased and intensified Weather Alert Events, combined with above 30-year average rainfall, have contributed to increased customer outages near historic levels in recent years. As shown in Figure SDB-2, the average number of customer outages over the past three years caused by these Weather Alert Events is significantly higher than the previous five years.

Figure SDB-2



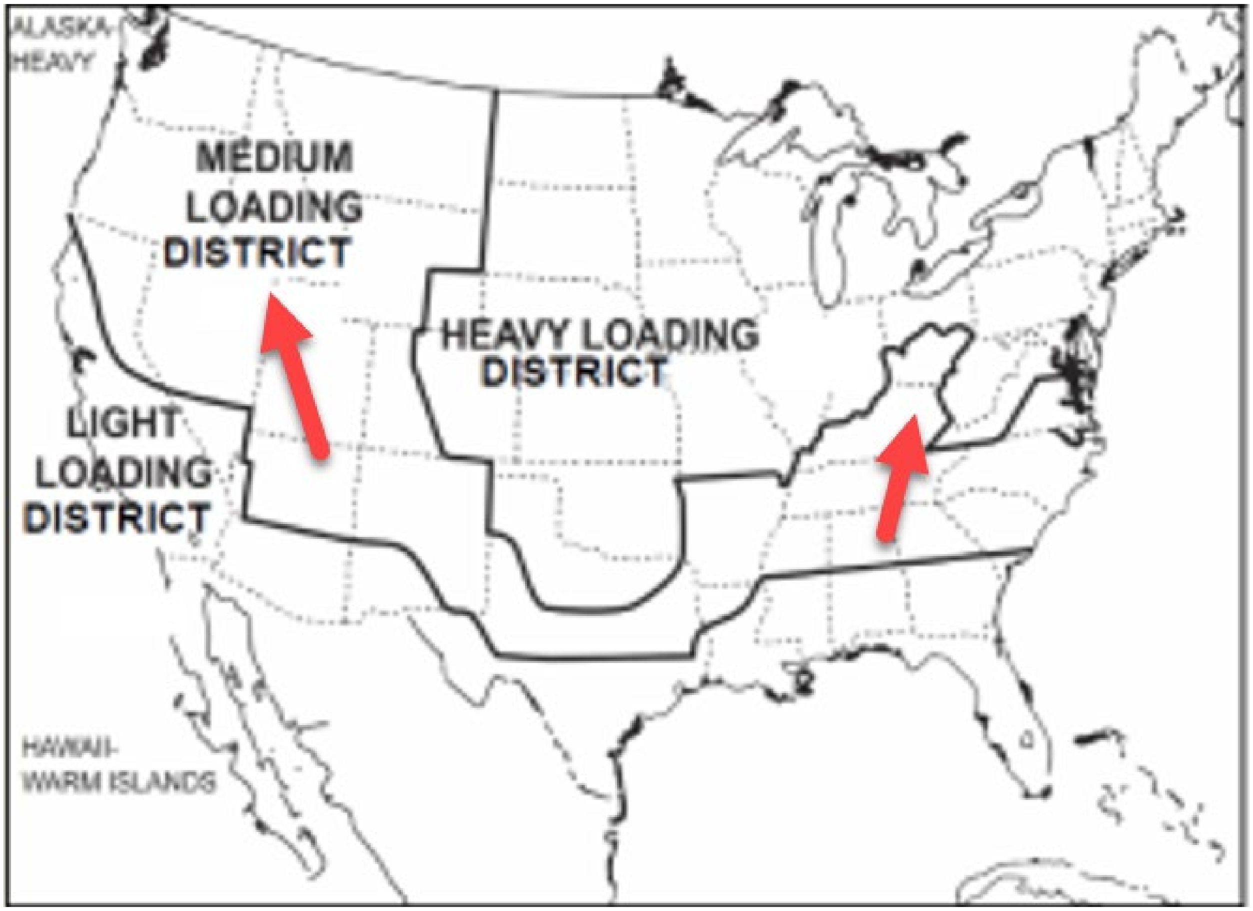
In sum, the increase in the number of customer outages is attributable to both the increasing number of Major Storm Events, as well as the magnitude and severity of these events.

Q. WHAT IS THE CURRENT NESC LOADING OF THE COMPANY'S DISTRIBUTION SYSTEM?

A. The 2023 National Electrical Safety Code ("NESC") contains safety rules for overhead lines, including detailed strength ("loading") requirements and clearance rules for the support structures, such as poles and cross arms.[2] Section 250 in the 2023 NESC describes the structural loadings for the United States. Figure SDB-3 below shows that the NESC requires medium loading in the Company's service territory.

[2] Lawrence M. Slavin, "NESC® Requirements (Strength and Loading)," in Overhead Distribution Lines: Design and Applications, IEEE, 2021, pp.45-61, doi: 10.1002/9781119699170.ch6.

Figure SDB-3



As detailed recently in Case No. 2021-00481 (proposed transfer of ownership of Kentucky Power), the Company's distribution lines were built to medium loading standards in accordance with NESC requirements, but the Company has been systematically upgrading to heavy loading standards over the last several years:

> Prior to 2014, Kentucky Power's distribution lines were built using the medium loading zone requirement of the National Electrical Safety Code (NESC), which means that the distribution line is built to withstand a 1/4 inch of ice. Although Kentucky is shown to be in the medium loading zone according to Figure 250-1 of the NESC (see JA_R_KIUC_2_39_Attachment1), in January of 2014, Kentucky Power began designing the distribution lines to meet heavy loading requirements, which means lines are now built to withstand up to a half inch of ice. It will

take several years to replace or modify over 210,000 poles and associated power lines to meet the heavy loading zone requirements.[3]

In 2014, Kentucky Power began utilizing a new line design tool enabling the Company to upgrade its distribution system from NESC medium loading to heavy loading. This line design tool uses a structural load case analysis with NESC heavy loading criteria on distribution poles and conductors. Specifically, the tool is used to design distribution lines for customer service, line construction and maintenance, reliability improvement projects, and various maintenance programs. Additionally, in 2009, the Commission issued a report after the September 2008 Wind Storm and the January 2009 Ice Storm recommending that "…utilities consider upgrading to heavy loading standards in some circumstances. For example, it may be beneficial to shorten span lengths when building lines in treed areas, thus improving the ability of those lines to sustain the weight of fallen vegetation."[4]

Q. HOW IS THE COMPANY'S DISTRIBUTION LINE LOADING RELEVANT TO THE WEATHER ALERT EVENTS AND MAJOR STORM EVENTS YOU HAVE BEEN DISCUSSING?

A. It is relevant in contextualizing the severity of several of the recent Major Storm Events the Company's service territory has experienced. For example, during the February 2021 Ice and Snow Storms, the amount of ice that accumulated on portions of the Company's system exceeded even the NESC heavy loading guidelines – the highest distribution structure strength requirements in place anywhere in the United

[3] *See* Exhibit SDB-2, Company's response to KIUC 2-39, *In The Matter Of: Electronic Application of American Electric Power Company, Inc., Kentucky Power Company and Liberty Utilities Co. For Approval of the Transfer of Ownership and Control of Kentucky Power Company*, Case No. 2021-00481 (February 14, 2022).

[4] *See* The Kentucky Public Service Commission Report on the September 2008 Wind Storm and the January 2009 Ice Storm, "Ike and Ice Report," November 19, 2009, Finding and Recommendation B1, at page 83.

State. Thus, even if all portions of the Company's distribution system had been constructed to meet the highest applicable national standards at the time of the event, the distribution system still could not have withstood that magnitude of ice, and the event still would have resulted in significant damage and customer outages.

Furthermore, the ice from the storm weighed down trees causing some to fall and damage the Company's distribution facilities. This damage also still would have occurred regardless of the loading standards to which the Company's distribution system was built. Company Witness Phillips discusses the proposal to enhance the Company's trees outside of the rights-of-way program, which would mitigate tree-related infrastructure damage and outages going forward.

V. MAJOR STORM EVENTS' IMPACT ON KENTUCKY POWER'S SYSTEM

Q. PLEASE SUMMARIZE THE ELEVEN MAJOR STORM EVENTS THAT IMPACTED THE COMPANY'S SYSTEM.

A. Kentucky Power experienced 11 Major Storm Events between January 11, 2020 and April 1, 2023 that resulted in storm restoration costs totaling $79.3 million above the level of such costs in the Company's current base rates. These major events included high windstorms, thunderstorms, straight-line wind storms, ice and snow storms, and rainstorms that caused mudslides and/or flooding. Figure SDB-4 summarizes the dates, type, and customer impacts of the Major Storm Events.

Figure SDB-4

Major Storm Event	Outages	Total Customers Impacted	CMI
January 11, 2020 High Wind Storm	190	10,673	4,507,240
April 8-9 2020 Thunderstorms	153	10,656	5,206,342
April 12, 2020 Straight-Line Wind Storm	909	72,459	200,900,139
December 24-25, 2020 Snow Storm	105	8,531	9,343,938
February 2021 Ice and Snow Storms (February 10, 15, and 17)	1,950	110,365	381,441,588
February 28, 2021 Major Flood Event	194	19,108	18,238,339
June 17, 2022 Thunderstorms and High Winds Event	437	27,794	28,828,056
July 28, 2022 Historic Flood Event	669	60,954	168,832,446
March 3, 2023 High Winds Event	349	28,049	21,744,501
March 25, 2023 High Winds Event	244	17,139	8,297,558
April, 2023 High Winds Event	516	35,318	32,241,177

<u>January 11, 2020 High Wind Storm</u>

Q. PLEASE DESCRIBE THE JANUARY 11, 2020 HIGH WIND STORM.

A. Strong winds (gusts peaking at 58 mph) associated with intense rain showers immediately along a cold front, damaged structures, downed trees, and caused power outages all across eastern Kentucky on January 11, 2020. The rain and high winds caused significant damage to Kentucky Power's system, knocking down trees and utility poles, damaging pole mounted transformers, and causing power outages for thousands of Kentucky Power customers. Earlier heavy rainfall also led to a large mudslide along U.S. Highway 421 near Hyden, in Leslie County, which caused large trees and rocks to fall into and block the road.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE JANUARY 11, 2020 HIGH WIND STORM.

A. The Company utilized the ICS for restoration efforts in connection with this storm, which I explain in further detail later in my testimony. The Company experienced a total of 190 outage cases, impacting a total of 10,673 customers for a total of 4,507,240 customer minutes of interruption ("CMI"). Nearly all outages were caused by the high winds and mudslides near the Company's distribution facilities. Kentucky Power repaired and replaced 27 poles, 5 cross arms, 8 distribution transformers, and approximately 158 spans of conductor as a result of the storm. The actual total distribution system cost to restore service to customers was $1,038,054, of which $646,479 was the actual jurisdictional incremental O&M expense attributable to the storm.[5]

__April 8-9, 2020 Thunderstorms__

Q. PLEASE DESCRIBE THE APRIL 8-9, 2020 THUNDERSTORMS.

A. Beginning the afternoon of April 8, 2020, and continuing into the morning on April 9, 2020, severe thunderstorms producing high winds up to 46 mph and hail passed through Kentucky Power's service territory. The storms damaged structures, downed trees, and caused power outages throughout Kentucky Power's service territory. The thunderstorm and high winds caused significant damage to Kentucky Power's system,

[5] *See* Order at 2*, In the Matter of: Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To the Extraordinary Expenses Incurred By Kentucky Power Company In Connection With Three 2020 Major Storm Events,* Case No. 2020-00368 (Ky. P.S.C. February 5, 2021).

knocking down trees and utility poles, damaging pole mounted transformers, and causing power outages for thousands of Kentucky Power customers.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE APRIL 8-9, 2020 THUNDERSTORMS.

A. The Company experienced a total of 153 outage cases, impacting a total of 10,656 customers for a total of 5,206,342 CMI. Nearly all outages were caused by the high winds and hail near the Company's distribution facilities and high winds causing structure and conductor damage to the Company's transmission facilities. Kentucky Power repaired and replaced 17 poles, 2 cross arms, 5 distribution transformers, and approximately 84 spans of conductor on its distribution system and 3 structures, 2 cross arms, multiple damaged insulators and multiple spans of conductor on its transmission system as a result of the storm. The actual distribution and transmission costs were $666,335 and $260,645 (totaling $926,980), respectively, of which $474,856 was the actual jurisdictional incremental O&M expense attributable to the storms.[6]

<u>April 12, 2020 Straight-Line Wind Storm</u>

Q. PLEASE DESCRIBE THE APRIL 12, 2020 STRAIGHT-LINE WIND STORM.

A. A strong storm system with straight-line winds moved through eastern Kentucky and Kentucky Power's service territory with sustained winds of more than 40 mph and gusts as high as 79 mph. The high winds caused extensive damage within the Company's service territory, downing trees and power lines, damaging buildings, and

[6] *See id.*

causing several roadways to be blocked into the morning of April 13, 2020. The storm also caused widespread power outages in the Company's Ashland, Hazard, and Pikeville districts.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE APRIL 12, 2020 STRAIGHT-LINE WIND STORM.

A. The Company utilized the ICS for restoration efforts as well as mutual assistance in connection with this storm. The Company experienced a total of 909 outage cases, impacting a total of 72,459 customers for a total of 200,900,139 CMI. Nearly all outages were caused by the high winds near the Company's distribution facilities and high winds causing structure and conductor damage to the Company's transmission facilities. Kentucky Power repaired and replaced 305 poles, 604 cross arms, 169 distribution transformers, and approximately 1,128 spans of conductor (for a distance of approximately 172,993 feet of conductor) on its distribution system, and 7 structures, 3 cross arms, and multiples spans of conductor on its transmission system as a result of the storm. The Company further removed an in-line switch damaged by the storm and had to relocate a 1-mile line section of the Hazard-Leslie 69 kV circuit. The actual costs to restore service to customers were $15,185,740 for Kentucky Power's distribution system, and $2,999,277 for its transmission system ($18,185,017 total), of which $9,843,199 was the actual jurisdictional incremental O&M expense attributable to the storm.[7]

[7] *See id*.

<u>December 24-25, 2020 Snow Storm</u>

Q. PLEASE DESCRIBE THE DECEMBER 24-25, 2020 STORM.

A. On Thursday, December 24, 2020 and continuing through mid-day December 25, 2020, a snow storm swept through the Company's service territory resulting in accumulations of 4-8 inches of heavy, wet snow causing widespread power outages in the Ashland, Hazard, and Pikeville Districts. Initially, the weight of the snow weakened (and broke) tree limbs causing outages; as melting occurred the weakened limbs sprang back up and caused new outages. Thus, restoration efforts were hindered as new outages continued to occur while older outages were restored due to the melting of heavy snow. The snowstorm caused damage to Kentucky Power's system, knocking down trees and utility poles, damaging pole mounted transformers, and causing power outages for thousands of Kentucky Power customers.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE DECEMBER 24-25, 2020 STORM.

A. The Company experienced a total of 105 outage cases, impacting a total of 8,531 customers for a total of 9,343,938 CMI. Kentucky Power repaired and replaced 6 poles, two transformers/oil spills, and approximately 182 spans of conductor as a result of the snow storm. There also were a total of two forced transmission line outages in the Hazard district. All outages were attributed to ice and snow that caused conductor damage to Kentucky Power transmission facilities. The first outage (Daisy – Leslie 69kv circuit) was caused by heavy ice that caused the conductor to sag into the tree tops, causing the conductor to burn in two. The second outage (Leslie – Pineville 161kv circuit) was caused by a broken ground wire that made contact with the conductor. Company personnel responded and repaired the broken conductors and stabilized the loose ground wires for both circuits. The estimated cost associated with the storm was $1,653,486, of which $1,043,892 was the actual jurisdictional incremental O&M expense attributable to the storm.[8]

<u>February 2021 Ice And Snow Storms</u>

Q. PLEASE DESCRIBE THE FEBRUARY 2021 ICE AND SNOW STORMS.

A. Between February 10, 2021 and February 17, 2021, Kentucky Power's service territory experienced three ice and snow storms that caused extensive damage and widespread power outages in the Company's Ashland, Hazard, and Pikeville Districts. The storms brought down power lines and ice-laden trees causing extensive debris and damage that required a massive cleanup effort. The first ice storm extended from February 10, 2021 to February 11, 2021 and resulted in 0.25"-0.50" of ice accumulation. The ice caused widespread outages as it brought down power lines and caused ice-laden trees to fall on lines. The storm damage was of such a magnitude and so extensive that outside resources were brought in to assist in restoration efforts. Beginning February 8, 2021, the Commonwealth's Division of Emergency Management established a winter storm event, and Governor Beshear on February 11, 2021 declared a State of Emergency across Kentucky due to the severe weather. The second ice storm extended from February 15, 2021 to February 16, 2021 and resulted in an additional 0.25"-0.50" of ice accumulation. Following the second ice storm, the total ice accumulation measured approximately 0.50"-1.00"

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[8] *See* Order at 5, *In the Matter of: Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To the Extraordinary Expenses Incurred By Kentucky Power Company In Connection With The December 24-25, 2020 Snow Storm,* Case No. 2021-00135 (Ky. P.S.C. April 5, 2021).

across much of the Company's service territory. In addition to bringing down additional trees into power lines, the ice accumulation also caused many roads to become impassable. Many areas also received four to six inches of snow on February 17, 2021. In addition to snow, this storm brought rising temperatures, causing some of the ice from previous storms to melt, which resulted in additional trees breaking and falling on power lines. The combination of snow and melting ice therefore caused additional outages. It also further hampered restoration efforts due to the resulting hazardous road conditions.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE FEBRUARY 2021 ICE AND SNOW STORMS.

A. The Company utilized the ICS for restoration efforts, as well as mutual assistance in connection with this storm. The Company experienced a total of 1,950 outage cases, impacting a total of 110,365 customers for a total of 381,441,588 CMI. The resulting damage to the Company's transmission and distribution systems was significant. The storms caused 759 broken poles, 1,176 damaged cross arms, 412 damaged transformers, and 851 damaged cutouts. Additionally, the Company repaired or replaced thousands of spans of conductor, totaling more than 116 miles (nearly equal to the distance between Lexington, Kentucky and Ashland, Kentucky). Many of the outages experienced included multiple outages suffered by the same customers who had their service restored only to lose service again when the successive storms swept through Kentucky Power's service territory. The restoration efforts took nearly three weeks, and early restoration efforts frequently were impaired or were required to be repeated after new outages occurred from additional ice and/or snow. Restoration crews and thousands of employees and contractors from ten states assisted in restoring service to the Company's customers over the course of the three weeks. The estimated cost associated with the storm was $76,433,065, of which $46,199,297 was the actual jurisdictional incremental O&M expense attributable to the storm.[9]

<u>February 28, 2021 Major Flood Event</u>

Q. PLEASE DESCRIBE THE FEBRUARY 28, 2021 MAJOR FLOOD EVENT.

A. While the Company was still engaged in recovery efforts after the three February 2021 ice and snow storms, beginning late Friday night February 26, 2021 and continuing through March 1, 2021, Kentucky Power's service territory experienced a heavy rain event, resulting in severe flooding. Within 72 hours, most of Kentucky Power's service territory received 3.5 inches to 5.8 inches of rainfall. In select areas the service territory received 3.6 inches to 4.7 inches of rainfall within 24 hours. The Major Flood Event caused extensive flooding, damage, and widespread power outages mostly in the Company's Pikeville District. The Hazard and Ashland Districts also experienced flooding, damage, and power outages as a result of the Major Flood Event. On February 28, 2021, Governor Andy Beshear issued Executive Order 2021-135 declaring a state of emergency throughout the Commonwealth as a result of the severe weather system that generated heavy rain across the Commonwealth causing flash flooding, flooding, high wind gusts, mudslides, and landslides.

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[9] *See* Order at 4, *In the Matter of: Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To the Extraordinary Expenses Incurred By Kentucky Power Company In Connection With Three February 2021 Major Storm Events,* Case No. 2021-00129, (Ky. P.S.C. April 5, 2021); *see also* Notice of Filing Final Costs ("KPCO_Exhibit_3_Actual_Costs.xlsx.") (Post-Case Files, January 18, 2022).

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE FEBRUARY 28, 2021 MAJOR FLOOD EVENT.

A. The Company utilized the ICS for restoration efforts, as well as mutual assistance in connection with this storm. The Company experienced a total of 194 outage cases, impacting a total of 19,108 customers for a total of 18,238,339 CMI. The Company experienced significant access issues due to high flood waters and mudslides. These mudslides persisted even once the flood waters subsided. Accordingly, outside resources were brought in to assist with restoration efforts. The Major Flood Event resulted in approximately 12 broken poles, 33 pole relocations caused by mud slides, 17 damaged cross arms, and 68 downed spans of wire. The estimated cost associated with the storm was $2,006,759, of which $826,495 was the actual jurisdictional incremental O&M expense attributable to the storm.[10]

June 17, 2022 Thunderstorms and High Winds Event

Q. PLEASE DESCRIBE THE JUNE 17, 2022 THUNDERSTORMS AND HIGH WINDS EVENT.

A. The June 17, 2022 thunderstorms resulted in widespread wind gusts in the 40-65 mph range with several localized gusts of 65 to 80 mph. The thunderstorms caused extensive damage and widespread power outages in the Company's Ashland, Hazard, and Pikeville Districts. The storm damage was of such a magnitude and so extensive that outside resources were brought in to assist in restoration efforts.

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[10] *See* Order at 3, *In the Matter of: Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To the Extraordinary Expenses Incurred By Kentucky Power Company In Connection With The March 1, 2021 Major Storm Event,* Case No. 2021-00402 (Ky. P.S.C. April 5, 2021).

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE JUNE 17, 2022 THUNDERSTORMS AND HIGH WINDS EVENT.

A. The Company utilized the ICS for restoration efforts, as well as mutual assistance. The Company experienced a total of 437 outage cases, impacting a total of 27,794 customers for a total of 28,828,056 CMI. The event caused 53 broken poles, 52 damaged cross arms, and 11 damaged transformers. Additionally, the Company repaired or replaced 605 spans of conductor, totaling more than 23.6 miles. The restoration efforts took four days. Restoration crews and hundreds of employees and contractors from ten states assisted in restoring service to the Company's customers over the course of the four days. The estimated cost associated with the storm was $5,409,015, of which $3,401,582 was the actual jurisdictional incremental O&M expense attributable to the storm.[11]

<u>July 28, 2022 Historic Flood Event</u>

Q. PLEASE DESCRIBE THE JULY 28, 2022 HISTORIC FLOOD EVENT.

A. On July 28, 2022, Kentucky Power's service territory experienced complexes of thunderstorms which brought heavy rain, deadly flash flooding, mudslides, and landslides. At times rainfall rates exceeded four inches an hour with an estimated 14-16" of rainfall during the five-day catastrophic event. Most of the rainfall occurred during the evening of July 27, 2022 and morning of July 28, 2022. Flash flooding

[11] *See* Order at 2, *In the Matter of: Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To the Extraordinary Expenses Incurred By Kentucky Power Company In Connection With June 2022 and July 2022 Major Storm Events,* Case No. 2022-00293 (Ky. P.S.C. September 28, 2022).

presents the most dangerous kind of floods as it combines destructive power with incredible speed. Unsurprisingly, record flash flooding was exhibited across eastern Kentucky. The storm damage was of such a magnitude and so extensive that outside resources were brought in to assist in restoration efforts.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE JULY 28, 2022 HISTORIC FLOOD EVENT.

A. The Company utilized the ICS for restoration efforts, as well as mutual assistance in connection with this storm. The Company experienced a total of 669 outage cases, impacting a total of 60,954 customers for a total of 168,832,446 CMI. The July 28, 2022 Historic Flood Event caused 234 broken poles, 69 damaged cross arms, 33 damaged transformers, 13 damaged cutouts, and approximately 3,000 meters. The Company repaired or replaced 608 spans of conductor, totaling more than 23.7 miles. Additionally, there were 10 damaged substations: Bonnyman, Bulan, Burton, Chavies, Engle, Falcon, Haddix, Shamrock and Engle Tap, Topmost, and Whitesburg. Topmost was the worst hit experiencing 5 feet of water throughout the entire station. The restoration efforts took approximately two weeks. Restoration crews and approximately 1,168 employees and contractors from seven states assisted in restoring service to the Company's customers over the course of the two weeks. The estimated cost associated with the storm was $19,956,197, of which $11,449,177 was the actual jurisdictional incremental O&M expense attributable to the storm.[12]

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[12] *See* Order at 4, *In the Matter of: Electronic Application of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To the Extraordinary Expenses Incurred By Kentucky Power Company In Connection With June 2022 and July 2022 Major Storm Events,* Case No. 2022-00293 (Ky. P.S.C. September 28, 2022); *see also* Notice of Filing Actual Costs ("KPCO_Exhibit_3_Actual_Costs.xlsx.") (Post-Case Files, April 26, 2023).

<u>March 3, 2023 High Winds Event</u>

Q. PLEASE DESCRIBE THE MARCH 3, 2023 HIGH WINDS EVENT.

A. On March 3, 2023, Kentucky Power's service territory experienced thunderstorms and high winds that caused extensive damage and widespread power outages in the Company's Ashland, Hazard, and Pikeville Districts. Prior to the high winds event, between March 2, 2023 and March 3, 2023, the Jackson, KY area also received 0.76" of rainfall. The National Weather Service reported multiple wind gusts between 40-60 miles per hour ("mph") across the Company's service territory with a peak wind gust of 68 mph recorded near Index, KY.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE MARCH 3, 2023 HIGH WINDS EVENT.

A. The Company utilized the ICS for restoration efforts, as well as mutual assistance in connection with this storm. The Company experienced a total of 349 outage cases, impacting a total of 28,049 customers for a total of 21,744,501 CMI. Damage to 36 transformers, 58 broken poles, 64 sets of cross arms, 25 cutouts, and 449 spans of conductor occurred during this Major Storm Event. The damage was so extensive that outside resources were brought in to assist with restoration efforts. The estimated cost associated with the storm was $5,436,349, of which $3,295,455 was the actual jurisdictional incremental O&M expense attributable to the storm.[13]

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[13] *See* Order at 3, *In the Matter of: Electronic Application Of Kentucky Power Company For An Order Approving Accounting Practices To Establish A Regulatory Asset Related To The Extraordinary Expenses Incurred By Kentucky Power Company In Connection With The March 3, 2023, March 25, 2023, And April 1, 2023 Major Event Storms,* Case No. 2023-00137 (Ky. P.S.C. June 5, 2023).

<u>March 25, 2023 High Winds Event</u>

Q. PLEASE DESCRIBE THE MARCH 25, 2023 HIGH WINDS EVENT.

A. Between March 24, 2023 and March 25, 2023, the Jackson, KY area received 1.05" of rainfall. On March 25, 2023, Kentucky Power's service territory experienced high winds that caused extensive damage and widespread power outages in the Company's Ashland, Hazard, and Pikeville Districts. The National Weather Service reported multiple wind gusts between 40-55 mph across the Company's service territory with a peak wind gust of 55 mph recorded near Jackson, KY.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE MARCH 25, 2023 HIGH WINDS EVENT.

A. The Company utilized the mutual assistance for restoration efforts in connection with this storm. The Company experienced a total of 244 outage cases, impacting a total of 17,139 customers for a total of 8,297,558 CMI. Damage to 6 transformers, 21 broken poles, 33 sets of cross arms, 3 cutouts, and 312 spans of conductor occurred during the Major Storm Event. Damage was so extensive that outside resources were brought in to assist with restoration efforts. The estimated cost associated with the storm was $1,573,935, of which $1,028,326 was the actual jurisdictional incremental O&M expense attributable to the storm.[14]

<u>April 1, 2023 High Winds Event</u>

Q. PLEASE DESCRIBE THE APRIL, 2023 HIGH WINDS EVENT.

A. Between March 31, 2023 and April 1, 2023, the Jackson, KY area received 1.78" of rainfall. On April 1, 2023, Kentucky Power's service territory experienced high

[14] *See id*. at 4.

winds that caused extensive damage and widespread power outages in the Company's Ashland, Hazard, and Pikeville Districts. The National Weather Service reported multiple wind gusts between 40-70 mph across the Company's service territory with a peak wind gust of 70 mph recorded near Dorton, KY.

Q. PLEASE DESCRIBE THE DAMAGE TO THE COMPANY'S SYSTEM CAUSED BY THE APRIL 1, 2023 HIGH WINDS EVENT.

A. The Company utilized the ICS for restoration efforts, as well as mutual assistance in connection with this storm. The Company experienced a total of 516 outage cases, impacting a total of 35,318 customers for a total of 32,241,177 CMI. Damage to 45 transformers, 77 broken poles, 70 sets of cross arms, 52 cutouts, and 538 spans of conductor occurred during the Major Storm Event. Damage was so extensive that outside resources were brought in to assist with restoration efforts. The estimated cost associated with the storm was $6,971,039, of which $5,643,197 was the actual jurisdictional incremental O&M expense attributable to the storm.[15]

VI. STORM PREPARATION AND RESPONSIVENESS

Q. PLEASE DETAIL KENTUCKY POWER'S STORM PREPAREDNESS EFFORTS.

A. Even before the Company's storm response procedures are triggered by a storm event, like the ones described in this testimony, the Company is actively ensuring that its system and employees are prepared for and able to respond to storms quickly and efficiently in order to restore service to customers as soon as possible. Kentucky

[15] *See id.*

Power's storm preparedness efforts fall into two broad categories: (a) system hardening and resiliency; and (b) storm responsiveness. System hardening includes Kentucky Power's systematic approach to improving the existing infrastructure to make it more durable for both normal operating conditions and weather-related events. Grid resiliency efforts are designed to minimize the number of customers affected by an outage, as well as to enable the Company to restore power outages more quickly and efficiently when outages occur. There often is an overlap between system hardening and system resiliency activities, which are discussed in more detail by Company Witness Phillips.

The second category, storm responsiveness, includes Kentucky Power's regular and ongoing efforts to respond quickly when a major storm strikes, which I discuss in detail below.

Kentucky Power Company's Storm Responsiveness Overview

Q. PLEASE GIVE AN OVERVIEW OF HOW THE COMPANY ANTICIPATES AND PREPARES TO RESPOND TO STORMS.

A. Prior to a storm event, the AEP Meteorology team and the Company actively monitor the weather. To help determine if the weather will be severe, the AEP Meteorology team and the Company utilize a Storm Outage Prediction Model ("SOPM"). The SOPM application is a resource planning tool that uses historical weather events and utility damage to create predictions of utility damage due to the weather forecast. This is a critical tool in the Company's proactive preparation and response to adverse weather situations. As much as three days prior to a storm event, AEP Meteorology uses the SOPM predictions, along with their expertise and experience, to engage with the Company to help determine the appropriate preparatory steps to be taken. This includes helping the Company determine resource needs based upon the customer and damage outage predictions. If the predictions indicated that the storm will be severe enough, the Company will take the following steps as part of its storm response:

1. Incident Command System
2. Storm Preparation
3. Base Camps, Staging Sites, and Materials
4. Hazard Removal and Reconnaissance Assessments
5. Restoration Implementation
6. Safety

1. <u>Incident Command System</u>

Q. WHAT IS THE ORGANIZATION STRUCTURE THE COMPANY USES TO CARRY OUT MAJOR STORM EVENT RESTORATION?

A. The Company utilizes the Incident Command System ("ICS") during Major Storm Events. ICS is a standardized, on-scene, all-hazard incident management tool that allows responders to manage both small and large emergencies such as outages related to major storms and other events requiring quick responses. ICS is the same process used by other utilities and agencies such as the military and local and state government emergency responders in responding to emergencies. Its key element is a common chain of command where the roles are clearly defined. ICS's Benefits include that it:

- Establishes consistent roles and responsibilities;
- Separates key restoration roles, i.e., operations, planning, logistics, finance and safety;
- Limits spans of control;

- Clearly defines and limits the focus of employee's responsibilities during the restoration or emergency response;
- Provides standardized terminology that will allow for effective and efficient communication internally and with local, state, and federal government agencies; and
- Allows the Company to share resources efficiently and effectively regardless of the incident size and transition employees throughout the service area during events.

Q. PLEASE DESCRIBE THE OBJECTIVES OF THE ICS.

A. The primary objective of the ICS is to establish an emergency operation structure that will efficiently utilize all available resources to resolve the emergency situation. The ICS allows the Company to accomplish rapid and orderly repair of electric facilities for the protection of public health and safety and the restoration of services to all customers in the minimum time possible.

The second objective of the ICS is to provide for the timely collection of accurate damage assessment reports for management, employees, and the general public. The reports include such information as the extent of any damage to the distribution and transmission systems and the progress made in restoring service.

Q. PLEASE DESCRIBE THE COMPANY'S KEY FUNCTIONS UNDER THE ICS.

A. When a major emergency or disaster occurs, the first function of Company personnel is to clear all known public hazards, such as downed power lines, which pose an immediate danger to the public. The second function is to conduct a detailed assessment of the damage to the affected systems so that the Company can procure the necessary resources and management can position crews appropriately for the efficient restoration of service. The third function is to restore service to the most customers in the shortest time while keeping in focus restoration of service to vital community services and installations (critical loads). The fourth function is to restore service to all remaining customers as quickly as possible.

Q. DOES THE COMPANY UTILIZE OTHER RESOURCES ASIDE FROM COMPANY PERSONNEL DURING A MAJOR STORM EVENT?

A. Yes. The Company also engages help from Regional Mutual Assistance Groups ("RMAGs").

Q. PLEASE DESCRIBE MUTUAL ASSISTANCE RESOURCES.

A. AEP is a member, and by extension Kentucky Power Company, of several RMAGs, including Texas Mutual Assistance Group, Midwest Mutual Assistance Group, and Great Lakes Mutual Assistance Group. Membership in these groups provides for a potential source of additional assistance from other utilities as needed. Mutual assistance is used by utilities to facilitate the restoration of service as rapidly as possible after a storm or other adverse situation by supplementing a utilities' workforce with additional resources to safely and efficiently recover from an outage event. Additionally, the Company is a member of the non-profit trade association, Southeastern Electric Exchange ("SEE"), which is the largest Mutual Assistance resource in the country.

2. Storm Preparation

Q. PLEASE DESCRIBE HOW KENTUCKY POWER PREPARES TO RESPOND TO MAJOR STORM EVENTS.

A. Kentucky Power prepares for storms by utilizing the aforementioned SOPM tool and ICS structure along with its ongoing efforts to lay the groundwork to respond quickly when a major storm strikes. As I discussed above, procedures are in place to assess a storm before it hits using intelligent weather monitoring services, and when required, to ramp up personnel, communications, materials, equipment and outside resources, including mutual assistance, to match the severity of the storm. The Company also conducts training exercises periodically to ensure key employees understand their role and can practice their response.

3. Base Camps, Staging Sites, And Materials

Q. WHAT ARE BASE CAMPS AND STAGING SITES?

A. Base camps are locations where primary logistics functions for personnel for an incident are coordinated. Base camps are equipped and staffed to provide sleeping quarters, food, water, and sanitary services, as needed, to incident personnel. Staging sites are locations set up for an incident where materials can be placed while awaiting tactical assignment. During a Major Storm event, the Company's service centers can function as a staging site. Depending on the circumstances, locations may serve both as base camps for personnel and staging sites for materials.

Q. HOW ARE THE BASE CAMPS AND STAGING SITES GENERALLY SELECTED AND ORGANIZED?

A. The Company has relationships with most of the sites utilized as a part of the overall planning process for a snow or ice storm or similar event. The locations are chosen due to the availability of space necessary to establish a base camp or staging area in support of restoration efforts as well as their proximity to the Company's assets and the area impacted by the storm.

Q. DOES THE ESTABLISHMENT OF BASE CAMPS HELP WITH THE COMPANY'S RESTORATION EFFORTS?

A. Yes. In some situations, the Company takes the action to set up base camps, and that decision can help save restoration time. For example, during the February 2021 Ice and Snow Storms, the ice accumulation caused many roads to become treacherous or even impassable for several days, as temperatures never got above 32 degrees until February 21st; without the establishment of base camps closer to the restoration areas, the Company would no doubt have needed additional time to restore customers. With impassable roads, as well as some hotels being out of service, establishing base camps was the best housing option. An additional advantage of establishing base camps, is that meals could be provided during the duration of the storm. This was practical, as not only were restaurants closed or were inaccessible due to the roads, but providing meals where the restoration workers were stationed provided time savings.

Q. DID THE COVID PANDEMIC PRESENT ADDITIONAL CHALLENGES REGARDING THE ESTABLISHMENT AND LAYOUT OF THE BASE CAMPS FOR ANY OF THE ELEVEN MAJOR STORM EVENTS?

A. Yes. Due to the safety measures required as a result of COVID-19, social distancing prevented the base camps utilized during the February 2021 Ice and Snow Storms from being filled to normal occupancy. The Company, as well as the RMAGs, were following the Centers for Disease Control and Prevention ("CDC") Guidelines which restricted the capacity of the bunk trailers used within the base camps. However, the use of base camps for this Major Storm Event was the most feasible housing approach, due to the inaccessibility of roads to and from hotels, and the COVID-19 social distancing policy would have only allowed one occupant per hotel room.

Q. HOW DOES THE COMPANY ENSURE THAT IT HAS ADEQUATE MATERIALS FOR STORM RESTORATION EFFORTS?

A. The Company maintains stock of materials and supplies, which is held in storeroom locations throughout the Company's service territory and can be pre-staged in strategic locations during a storm event. As part of the ICS, a storm stock list that anticipates material demands to restore the system is maintained. From this list, pallets of the anticipated materials are developed and made ready for delivery to the locations of need. The list also serves as the basis for the initial storm orders of material to replace that used during the early stages of restoration.

4. <u>Hazard Removal and Damage Assessments</u>

Q. WHAT IS THE FIRST FUNCTION OF KENTUCKY POWER PERSONNEL AFTER THE ARRIVAL OF A STORM?

A. The first function of Company personnel after a storm hits is to clear all known public hazards that pose an immediate danger to the public.

Q. WHAT TYPES OF DISTRIBUTION HAZARDS EXIST AFTER SUCH STORMS?

A. Distribution lines and poles may be down across highways, roads, and streets. In some instances, the downed facilities may block passage completely, while in other instances, facilities may still be energized and thereby prevent safe passage across them. Also, as previously mentioned, the weather itself can pose hazards, such as making roads treacherous or impassable. As another example, as was the case during the July 28, 2022 Historic Flood Event, some of the Company's assets were completely submerged by flood waters and could not be accessed.

Q. PLEASE DESCRIBE HOW HAZARDS ARE IDENTIFIED AND ADDRESSED DURING AND AFTER THE STORMS.

A. Hazard assessment is an important component of the overall assessment process. Hazards are identified through calls from customers or civil authorities during the damage assessment process or by first responders and repair crews. Once a hazard location is identified, it is cleared, made safe, and assessed for repair, and guarded by qualified individuals until it can be mitigated, or, in cases where energized facilities are not involved, made safe by the placement of cones, barricade tape, or other suitable barrier until the facilities can be repaired.

Q. WHAT IS THE SECOND FUNCTION OF KENTUCKY POWER PERSONNEL AFTER THE ARRIVAL OF THE STORMS?

A. The second function is to conduct a detailed assessment of the damage to the affected systems so that necessary resources can be procured and management can position crews appropriately for the efficient restoration of service. In the event of a major restoration effort, it is very important to make a high-level damage assessment or reconnaissance early in the outage event. The earlier the need for additional resources is identified, the sooner those resources can be mobilized for the restoration effort.

Q. HOW IS THE RECONNAISSANCE ASSESSMENT CONDUCTED?

A. The reconnaissance assessment includes the following:

- Geographical description of the area involved
- Stations and/or circuits affected
- Equipment damaged and/or hazardous situations
- Estimated number of customers affected by district
- Restoration plans (manpower and material needs)
- Estimated restoration time

The reconnaissance assessment is followed as early as possible with assessment of major interruptions and three phase outages and finally a complete circuit detailed assessment.

5. <u>Restoration Implementation</u>

Q. PLEASE DESCRIBE THE COMPANY'S RESTORATION STRATEGY DURING A MAJOR STORM EVENT.

A. After hazard removal and damage assessment, the Company's third function is to restore service to the most consumers in the shortest time while keeping in focus restoration of service to vital community services and installations (critical loads). The fourth function is to restore service to all remaining users as quickly as possible.

Q. PLEASE DESCRIBE THE COMPANY'S STRATEGY TO RESTORE SERVICE TO ESSENTIAL SERVICES/CRITICAL LOADS.

A. The Company establishes guidelines to assist in setting the priority order in which assessed outages are worked. Critical loads are essential services to the safety, health and welfare of the community and given priority over other outages during restoration efforts. The Company has worked collaboratively with community leaders to identify these critical loads which include:

- Hospitals and health support facilities
- Fire, law enforcement and essential governmental agencies
- Water and sewage treatment facilities
- Perishable food processors
- Media communication centers
- Federal Aviation Administration Navigational Facilities

Q. PLEASE DESCRIBE HOW THE COMPANY IMPLEMENTS ITS STRATEGY TO RESTORE SERVICE TO THE MOST CUSTOMERS IN THE SHORTEST AMOUNT OF TIME.

A. In order to restore service to the most customers in the shortest amount of time, the Company generally works through restoration in the following overall order, prioritizing the stability and integrity of the entire transmission and distribution grid:

- Transmission circuits that could result in cascading station outages (outages that could lead to outages on subsequent circuits if overall demand remains the same after the initial outage)
- Subtransmission circuits that could also result in cascading station outages
- Subtransmission circuits that result in station outages
- Stations

- Distribution feeder circuits
- Distribution three phase branch circuits
- Two-phase and single-phase laterals
- Secondary/ Services
- Street lighting

Accordingly, for distribution, the first emphasis is on the feeder circuits, followed by the three-phase branch circuits, laterals, and secondary/services. Finally, street lighting is addressed. Of course, although this is the general work plan, the Company's crews in practice will work multiple facilities in parallel paths to the extent possible so that service can be restored as quickly as possible. Additionally, even though the overall work plan listed above indicates that restoration of transmission facilities comes prior to restoration of distribution facilities, the transmission and distribution work teams also proceed in parallel paths so that service can be restored as quickly as possible.

Q. WHAT IS THE BENEFIT OF INITIALLY FOCUSING ON THE FEEDER CIRCUITS IN THE RESTORATION PROCESS?

A. Focusing on the feeder circuits supports the restoration of the largest number of customers in the shortest time possible. A single feeder circuit may support service to as many as 1,000 customers whereas laterals, for example, may only support service to 10 customers. In practical terms, the feeder or "backbone" circuits feed smaller lateral circuits, and therefore need to be restored first.

Q. DOES THE COMPANY KEEP ITS CUSTOMERS AND OTHER STAKEHOLDERS INFORMED DURING RESTORATION EFFORTS?

A. Yes. The Company recognizes that timely communication is vital to the process of managing storm-related outages. Accordingly, the Company ensures that its customers, all those participating in the restoration effort, and the Commission remain apprised of all-important factors pertaining to the outage and restoration status of events. This is accomplished through the Company's One Voice Communication process. "One Voice" is a process that provides accurate and timely service restoration information to all interested parties – such as customers, the media, government, emergency management agencies and internal groups. The process promotes proactive communication and potentially answers many questions before they are even asked. Additionally, during larger storm events, such as those described above in my testimony, the Company provides periodic updates to the Commission until customer interruptions reach a certain threshold. Once the storm event has concluded, the Company is required to complete and submit a summary of the event.

6. <u>Safety</u>

Q. WHAT IS THE COMPANY'S PERSPECTIVE ON SAFETY DURING RESTORATION ACTIVITIES?

A. Kentucky Power and AEP are committed to the safety and health of its employees, external crews, contractors, and the general public. Our goal in every storm recovery event is "Zero harm" – no injuries or vehicle accidents.

Q. WHAT STEPS DOES THE COMPANY TAKE TO ENSURE SAFETY AMONG THE COMPANY'S EMPLOYEES AND THE CONTRACTOR PERSONNEL?

A. As noted above, the Company has safety representatives provide a safety orientation to mutual assistance and non-local contractor workers. This ensured that crews received the same message and were provided additional safety oversight. The training included live and video presentations and literature, plus information on local hospitals and regional cautions such as dangerous snakes and plants. Kentucky Power Safety personnel communicated daily with safety representatives from each of the mutual assistance and non-local companies. Kentucky Power also stationed Company safety representatives at each staging site who sat in on morning safety meetings with the non-local crews.

Q. PLEASE SUMMARIZE THE COMPANY'S STORM PREPARATION AND RESPONSIVENESS PROCESSES UTILIZED FOR THE 11 MAJOR STORM EVENTS.

A. The Company, as demonstrated in Figure SDB-5, followed its storm preparation and responsiveness processes during the 11 Major Storm Events to the extent necessary to ensure service was restored to our customers as quickly, efficiently, and safely as possible.

Figure SDB-5

Storm Preparation and Responsiveness Processes Utilized							
Major Storm Event	**ICS**	**Mutual Assistance**	**Storm Preparation**	**Base Camps (BC), Staging Sites & Materials (SS)**	**Hazard Removal & Reconnaissance Assessments**	**Restoration Implementation**	**Safety and Oversight**
January 11, 2020 High Wind Storm	Yes	No	Yes	SS	Yes	Yes	Yes
April 8-9 2020 Thunderstorms	No	No	Yes	SS	Yes	Yes	Yes
April 12, 2020 Straight-Line Wind Storm	Yes	Yes	Yes	SS	Yes	Yes	Yes
December 24-25, 2020 Snow Storm	No	No	Yes	SS	Yes	Yes	Yes
February 2021 Ice and Snow Storms (February 10, 15, and 17)	Yes	Yes	Yes	BC, SS	Yes	Yes	Yes
February 28, 2021 Major Flood Event	Yes	Yes	Yes	SS	Yes	Yes	Yes
June 17, 2022 Thunderstorms and High Winds Event	Yes	Yes	Yes	SS	Yes	Yes	Yes
July 28, 2022 Historic Flood Event	Yes	Yes	Yes	SS	Yes	Yes	Yes
March 3, 2023 High Winds Event	Yes	Yes	Yes	SS	Yes	Yes	Yes
March 25, 2023 High Winds Event	No	Yes	Yes	SS	Yes	Yes	Yes
April 1, 2023 High Winds Event	Yes	Yes	Yes	SS	Yes	Yes	Yes

VII. MAJOR STORM EVENT COSTS

Q. PLEASE SUMMARIZE THE COSTS OF THE 11 MAJOR STORM EVENTS THAT TOOK PLACE WITHIN THE COMPANY'S SERVICE TERRITORY BETWEEN JANUARY 2020 AND APRIL 2023.

A. Please see Figure SDB-6 below, which summarizes customers impacted and costs by Major Storm Event.

Figure SDB-6

Deferral Requested in Case No.	Storm Dates	Actual Total Costs	Actual Jurisdictional Incremental O&M Expense	Amount in Base	Approved Deferral Amount
2020-00368	January 11, 2020	$1,038,054	$646,480		$9,465,952
	April 8-9, 2020	$926,980	$474,856		
	April 12, 2020	$18,185,017	$9,843,199		
2021-00135	December 24-25, 2020	$1,653,486	$1,043,891		$1,043,892
Total 2020 Storms		**$21,803,537**	**$12,008,426**	**$1,498,582**	**$10,509,844**
2021-00129	February 10-11, 2021	$76,433,065	$46,199,297		$45,169,508
	February 15-16, 2021				
	February 17, 2021				
2021-00402	February 28, 2021	$2,006,759	$826,494		$826,495
Total 2021 Storms		**$78,439,824**	**$47,025,791**	**$1,029,789**	**$45,996,002**
2022-00293	June 17, 2022	$5,409,015	$3,401,582		$13,838,283
	July 26, 2022	$19,956,197	$11,449,177		
Total 2022 Storms		**$25,365,212**	**$14,850,759**	**$1,012,476**	**$13,838,283**

Deferral Requested in Case No.	Storm	Estimated Total Costs	Estimated Jurisdictional Incremental O&M Expense	Amount in Base	Estimated Deferral Amount**
2023-00137	March 3, 2023	$5,436,349	$3,295,455		$8,954,502
	March 25, 2023	$1,573,935	$1,028,326		
	April 1, 2023	$6,971,039	$5,643,197		
Total 2023 Storms*		**$13,981,323**	**$9,966,978**	**$1,012,476**	**$8,954,502**
Total Actual and Estimated Deferred Storm Costs Since 2020-00174					**$79,298,631**

*As of April 30, 2023
**The Company will file its final actual costs on or before September 30, 2023.

Exhibit SDB-1 includes a summary of storm costs for each of the 11 Major Storm Events by cost category. As stated by Company Witness West, the Company will be providing a detailed cost breakdown for each storm in response to Commission Staff's standard data request to provide all exhibits and schedules that were prepared in the utility's rate application.

Q. WHAT PROCESSES DOES THE COMPANY HAVE IN PLACE TO ENSURE THE PRUDENCY AND REASONABLENESS OF MAJOR STORM EVENT COSTS?

A. The Company has an onboarding process for mutual assistance as well as adheres to Edison Electric Institute ("EEI") governing principles for emergency assistance. The ICS uses a simple and effective check-in process as part of onboarding to establish resource accountability. Specifically, designated Company employees are given a roster of mutual assistance workers to ensure that the Company is receiving the agreed upon number of mutual assistance workers and is able to collect pertinent information for tracking and resource assignments. With this information, the Company knows what mutual assistance workers are on property, what areas and work they are assigned, as well as the hours that are worked. This helps the Company ensure that labor from mutual assistance is being properly charged. Through a systematic approach utilized as part of ICS, mutual assistance will be released in due course to help limit expenses incurred from these resources.

Although the Company utilizes formal contracts for mutual assistance so that items such as labor rates have already been established prior to a Major Storm Event, EEI member companies also use governing principles for emergency assistance during these types of events. The EEI governing principles include guidelines for costs and expenses incurred by mutual assistance resources as a result of furnishing emergency assistance. These costs and expenses include such items as wages, travel and living expenses, and replacement cost of material and supplies expended or furnished. After a Major Storm Event, Company personnel will review mutual assistance resource expenses to ensure that they followed these principles and were incurred properly for providing emergency assistance. For example, a properly incurred expense includes the mutual assistance wages and salaries paid while these resources are traveling to the Company's service territory to render emergency assistance.

Q. IN YOUR EXPERT OPINION, ARE ANY OF THE STORM COSTS A RESULT OF UNDERINVESTMENT IN THE COMPANY'S DISTRIBUTION SYSTEM?

A. No. As explained further by Company Witness Phillips and Company Witness West, the damage sustained to the Company's distribution system is not attributable to the Company's level of distribution investment. As discussed earlier in my testimony, the frequency and severity of storms has been substantially increasing in recent years. While the Company's distribution system was originally built to recommended NESC medium loading standards, the Company has been upgrading to higher NESC heavy loading standards where applicable. However, as was the case in the February 2021 Ice and Snow Storms, the amount of ice the storms brought were even above heavy loading standards and still would have caused considerable outages and damage even if the Company's entire distribution system met NESC heavy loading standards. Additionally, trees outside of the Company's ROW can either fall or be blown into the Company's distribution assets during Major Storm Events and cause outages. The Company has already implemented a pilot program and is proposing a more widespread targeted program to be implemented through the proposed Distribution Reliability Rider, to target these trees outside ROW, as discussed in more detail by

Company Witnesses West and Phillips. As such, despite the Company's prudent investment in its distribution system, it was necessary for the Company to incur the costs to restore service as safely and quickly as reasonably possible after each of the Major Storm Events described in this testimony.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company has demonstrated that the distribution-related O&M system restoration costs associated with 11 Major Storm Events that impacted the Company's service territory between January 2020 and April 2023 were reasonable and prudently incurred. Therefore, the Company is proposing to finance these costs through securitization, which request is supported and discussed in more detail by Company Witness West.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Stephen D. Blankenship, being duly sworn, deposes and says he is the Region Support Manager, for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Stephen D. Blankenship

Stephen D. Blankenship

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stephen D. Blankenship, on June 22, 2023.

Scott E. Bishop

Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

		2020-00368			2021-00135	Total 2020	2021-00129	2021-00402	Total 2021	2022-00293		Total 2022	2023-00137**			Total 2023 To Date*
		January 11, 2020	April 8-9, 2020	April 12, 2020	December 24-25, 2020		February 10-11; 15; and 17	February 28, 2021		June 17, 2022	July 26, 2022		March 3, 2023	March 25, 2023	April 1, 2023	
Total O&M by Category	**Salary and Wages**	$ 230,859	$ 139,708	$ 1,868,073	$ 263,268	$ 2,501,908	$ 3,082,331	$ 292,200	$ 3,374,531	$ 485,666	$ 2,853,945	$ 3,339,611	$ 509,213	$ 206,887	$ 410,842	$ 1,126,942
	Transportation	$ 55,926	$ 21,719	$ 424,346	$ 208,875	$ 710,865	$ 616,902	$ 152,411	$ 769,313	$ 26,391	$ 479,538	$ 505,929	$ 80,611	$ 48,750	$ 97,500	$ 226,861
	Other	$ 6,876	$ 3,856	$ 324,176	$ 16,290	$ 351,198	$ 9,946,877	$ 16,273	$ 9,963,150	$ 82,995	$ 565,617	$ 648,612	$ 147,471	$ 156,000	$ 390,000	$ 693,471
	Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
	Outside Contract Services (if applicable)	$ 491,868	$ 468,524	$ 8,646,426	$ 669,256	$ 10,276,074	$ 34,578,892	$ 709,387	$ 35,288,279	$ 3,097,623	$ 9,300,346	$ 12,397,968	$ 2,847,008	$ 720,000	$ 4,608,962	$ 8,175,970
	Total	$ 785,529	$ 633,807	$ 11,263,021	$ 1,157,689	$ 13,840,045	$ 48,225,002	$ 1,170,271	$ 49,395,273	$ 3,692,675	$ 13,199,446	$ 16,892,121	$ 3,584,303	$ 1,131,637	$ 5,507,304	$ 10,223,244
Incremental O&M by Category	**Salary and Wages**	$ 161,328	$ 118,249	$ 1,427,343	$ 222,313	$ 1,929,233	$ 2,184,187	$ 144,334	$ 2,328,521	$ 295,535	$ 1,904,513	$ 2,200,048	$ 369,083	$ 171,276	$ 716,440	$ 1,256,799
	Transportation	$ 4,392	$ 1,156	$ 33,319	$ 8,945	$ 47,812	$ 47,446	$ 5,660	$ 53,106	$ 1,364	$ 24,386	$ 25,750	$ 4,279	$ 2,673	$ 5,187	$ 12,140
	Other	$ 4,988	$ 3,202	$ 316,135	$ 14,607	$ 338,933	$ 9,941,049	$ 15,895	$ 9,956,944	$ 81,642	$ 551,662	$ 633,304	$ 145,352	$ 156,000	$ 390,000	$ 691,352
	Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Outside Contract Services (if applicable)	$ 475,773	$ 352,248	$ 8,066,401	$ 798,026	$ 9,692,448	$ 34,026,615	$ 660,605	$ 34,687,220	$ 3,023,042	$ 8,968,616	$ 11,991,657	$ 2,776,740	$ 698,376	$ 4,531,570	$ 8,006,686
	Total	$ 646,480	$ 474,856	$ 9,843,199	$ 1,043,891	$ 12,008,426	$ 46,199,297	$ 826,494	$ 47,025,791	$ 3,401,582	$ 11,449,177	$ 14,850,759	$ 3,295,455	$ 1,028,326	$ 5,643,197	$ 9,966,978
	Amount in base					$ 1,498,582			$ 1,029,789			$ 1,012,476				$ 1,012,476
	Approved Deferral Amount					$ 10,509,844			$ 45,996,002			$ 13,838,283				$ 8,954,502

*As of April 30, 2023
** Figures are estimated. The Company will file its final actual costs on or before September 30, 2023.

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's Second Set of Data Requests
Dated February 4, 2022

DATA REQUEST

KIUC 2_39 With respect to the $11 million incurred in the spring and winter of 2020 and the $75 million incurred in winter 2021 to repair the system and restore service in response to severe weather and storms, provide a copy of all analyses, root causes, and/or all other critiques performed by or for the Company that address the scope of physical damages, cost to repair the system and restore service, and/or proposals and/or recommendations to minimize such storm damages in the future. If no such analyses were performed, then describe why the Company did not engage in any self-assessments or third-party assessments.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding nor calculated to lead to the discovery of admissible evidence.

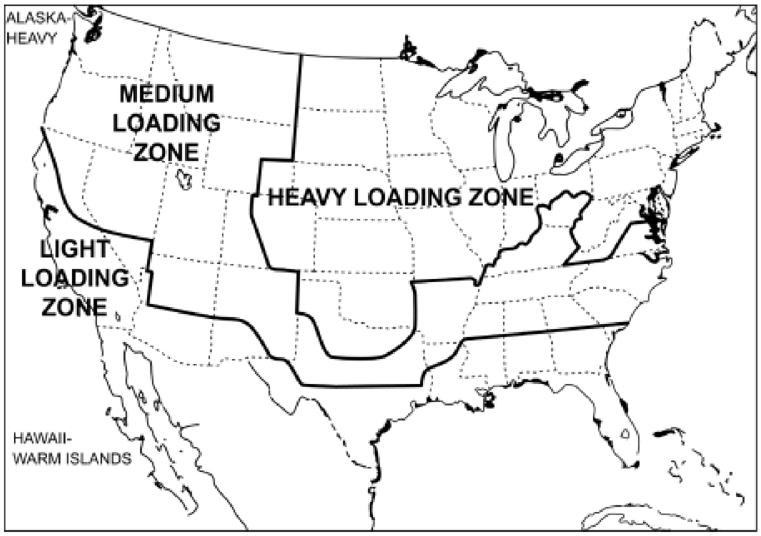
Subject to and without waiving this objection, the Joint Applicants state:

Each storm is unique in nature and after each storm, all charges were closely scrutinized to ensure accurate reporting of labor, equipment and material. The impacted areas were visually inspected to verify facilities were restored to normal and any hazardous conditions were mitigated. Some of the additional cost during the February 2021 storms were due to the fact there were three unusually destructive storms in one period that caused ice to accumulate to nearly one inch on trees and power lines. In addition, due to COVID protocols additional rooms and base camp trailers were needed to house employees and contractors.

No specific analyses were performed after the storms. However, Kentucky Power is taking steps to minimize storm damage in the future. Prior to 2014, Kentucky Power’s distribution lines were built using the medium loading zone requirement of the National Electrical Safety Code (NESC), which means that the distribution line is built to withstand a 1/4 inch of ice. Although Kentucky is shown to be in the medium loading zone according to Figure 250-1 of the NESC (see JA_R_KIUC_2_39_Attachment1.pdf), in January of 2014, Kentucky Power began designing the distribution lines to meet heavy loading requirements, which means lines are now built to withstand up to a half inch of ice. It will take several years to replace or modify over 210,000 poles and associated power lines to meet the heavy loading zone requirements.

Kentucky Power would demonstrate the prudency of the costs at issue in a future rate proceeding in which it seeks recovery of those cost. See also the Joint Applicants' response to AG 2-3.

Witness: Brian K. West



The Warm Island Loading District includes American Samoa, Guam, Hawaii, Puerto Rico, Virgin Islands, and other islands located from 0 to 25 degrees latitude, north or south.

Figure 250-1—General loading map of United States with respect to loading of overhead lines

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

TIMOTHY C. KERNS

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
TIMOTHY C. KERNS ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

TABLE OF CONTENTS

EXHIBITS

EXHIBIT	DESCRIPTION
Exhibit TCK-1	Company's Response to Commission's Staff Set 1, Question 6 in Case No. 2023-00145

DIRECT TESTIMONY OF
TIMOTHY C. KERNS ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Timothy C. Kerns. My business address is 200 Association Drive, Charleston, WV, 25311. In March 2023, I accepted the position of Vice President of Generating Assets for Appalachian Power Company ("Appalachian Power") and Wheeling Power Company ("Wheeling Power") effective April 2023. Appalachian Power and Wheeling Power are wholly owned subsidiaries of American Electric Power Company, Inc. ("AEP"). Immediately prior to my current role, I was Vice President of Generating Assets for Kentucky Power Company ("Kentucky Power" or "the Company") and Indiana Michigan Power Company ("I&M") from 2020 to 2023.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science in Mechanical Engineering Degree from West Virginia Institute of Technology and have been employed by AEP system companies for 34 years. I have worked at various power plants across the AEP System since 1989 in various positions including as a Performance Engineer, a

Maintenance Engineer, and a Plant Manager where, among other things, I performed, directed, and managed outage and non-outage maintenance and capital work. Specifically, from 1989 to 1996 I was a Performance, Maintenance and Environmental Engineer at the Philip Sporn Plant; from 1996-1998 I was an Equipment Troubleshooting Specialist for the Regional Services Organization ("RSO"); from 1998-1999 I was a Zone Superintendent for the RSO; from 1999-2000 I was a Regional Engineer Manager; from 2001 to 2006 I was the RSO Manager; from 2006-2011 I was the Plant Manager at the Tanners Creek and Lawrenceburg Plants; from 2011 to 2017 I was the Plant Manager at the Rockport Plant; from 2017 to 2020 I was the Managing Director of Generating Assets for I&M; and from 2020 to 2023 I was the Vice President of Generating Assets for Kentucky Power, Wheeling Power and I&M.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS VICE PRESIDENT GENERATING ASSETS FOR APPALACHIAN POWER AND WHEELING POWER.

A. In my new role I am responsible for the safe, reliable, and economic operation of the fossil-fueled generating assets owned and operated by the Companies. This includes the Amos, Mitchell, and Mountaineer coal-fired power plants, as well as the gas-fired Ceredo (simple-cycle combustion turbines), Clinch River (gas-fired boiler), and Dresden (combined-cycle) power plants, and Appalachian Power's hydro facilities. Specifically, I plan, organize, coordinate, direct, and control plant activities, including the operations, maintenance, engineering, and construction of the plant facilities. I also oversee plant budgets and interface with other AEP functional groups such as Accounting, Regulatory, and Commercial Operations to ensure the needs of the generating plants are met. Additionally, I am responsible for any decommissioning, demolition, and disposition of generating assets owned or operated by the Companies.

Q. PLEASE EXPLAIN YOUR FAMILIARITY WITH KENTUCKY POWER GENERATING ASSETS.

A. In my former role as Kentucky Power's Vice President of Generating Assets, I was responsible for the safe and reliable operation of Big Sandy Unit 1 and Mitchell Units 1 and 2 for over three years. More importantly, I was in the role throughout the test year for this proceeding.

Prior to the adoption of the resolutions identified in the Written Consent Action of the Mitchell Operating Committee, Kentucky Power was Mitchell Plant's operator until September 1, 2022. Until that time, I also had overall responsibility for the operation and maintenance of the Plant as the Company's Vice President of Generating Assets. I continue to have these responsibilities in my current role on behalf of Wheeling Power now that Wheeling Power is the operator for the Mitchell Plant. I am familiar with the day to-day operation of the Mitchell Plant as a result of my responsibilities in the oversight of Plant personnel in connection with the safe, reliable, and economic operation of the Plant. In this regard, my responsibilities include interacting on a regular basis with the Mitchell Plant manager, who reports directly to me, as well as with other Plant personnel in connection with both day-to-day and longer-term Plant activities. In addition, I regularly review budgets, review investments, and help plan the safe and reliable operation of that facility. I also continue to participate as a non-voting member of Mitchell Plant Operating Committee.

Lastly, as part of Wheeling Power's management team, I work in close coordination with the American Electric Power Service Corporation ("AEPSC") and Kentucky Power's Managing Director of Generating Assets to ensure the Mitchell Plant is safe, reliable and provides benefit to customers through effective management of O&M expenditures and capital investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony and testified on behalf of Kentucky Power before this Commission in Case Nos. 2020-00174 (2020 base rate case) and 2021-00421 (Mitchell Plant operating agreements). I have also submitted testimony on behalf of Wheeling Power before the West Virginia Public Service Commission ("WVPSC") in Case No. 21-0810-E-PC. In addition, I have submitted testimony and testified on behalf of I&M before the Indiana Utility Regulatory Commission in Cause Nos. 44967, 44511, and 45235, and the Michigan Public Service Commission in Cause Nos. U-18370, U-20070, and U-20359. Finally, I submitted testimony at the Federal Energy Regulatory Commission in AEP Generating Company's depreciation rate cases.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

- Describe Kentucky Power's generation assets;

- Describe and support the reasonableness of Kentucky Power's generation non-fuel, non-labor operation and maintenance ("O&M") expenses for the Mitchell and Big Sandy Plants;
- Describe the retired Big Sandy generating assets;
- Describe capital investments placed in-service at Kentucky Power's generating assets since the Company's last base case; and
- Describe the performance of the Company's generation fleet during Winter Storm Elliott.

Q. WHAT IS THE TEST YEAR FOR THIS PROCEEDING?

A. The test year in this proceeding is the twelve-month period from April 1, 2022 through March 31, 2023.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR TESTIMONY?

A. Yes. I am sponsoring the following exhibits attached to my testimony:

EXHIBIT	DESCRIPTION
Exhibit TCK-1	Company's Response to Commission's Staff Set 1, Question 6 In Case No. 2023-00145

IV. KENTUCKY POWER'S GENERATING ASSETS

Q. PLEASE DESCRIBE KENTUCKY POWER'S GENERATION ASSETS.

A. Kentucky Power's generation assets consisted of both owned and contracted generation capacity totaling 1,468 MW until December 7, 2022. Beginning December 7, 2022 through the 2022/2023 PJM planning year ending May 31, 2023, Kentucky Power's owned and contracted generation capacity totaled approximately 1,227 MW under the terms and conditions of the Power Coordination Agreement ("PCA").

Q. PLEASE BRIEFLY DESCRIBE KENTUCKY POWER'S OWNED GENERATION.

A. Kentucky Power's generation assets consist of a total of 1,075 MW of capacity from two generating plants, Big Sandy and Mitchell. The Company's assets and their characteristics are listed in Figure TCK-1.

Figure TCK-1: Kentucky Power Generation Assets

Plant	Kentucky Power-Owned Capacity (MW)	No. of Units	Location	Fuel	Expected Retirement Date
Big Sandy	295	1	Louisa, KY	Natural Gas	2031
Mitchell	780	2	Moundsville, WV	Coal	2040

Kentucky Power owns and operates the Big Sandy Plant located near Louisa, Kentucky. The plant currently has a single operating unit with a generating capacity of 295 MW. Big Sandy Unit 1 was originally placed in service in 1963 and operated as a 278 MW sub-critical coal-fired generating unit through mid-November 2015. As approved by the Commission in Case No. 2013-00430, and described later in my testimony, Big Sandy Unit 1 was converted to a natural gas-fired unit and returned to service May 31, 2016. The Unit is equipped with low nitrogen oxide ("NO_x") burners with overfire air for reduction of NO_x emissions.

The Mitchell Plant is located approximately 12 miles south of Moundsville, West Virginia on the Ohio River. Kentucky Power owns an undivided 50% interest in the Mitchell Plant; the other 50% interest is owned, and operated, by Wheeling Power. The plant comprises two super-critical pulverized coal-fired baseload generating units. Mitchell Unit 1 has a capacity of 770 MW and Mitchell Unit 2 has a capacity of 790 MW for a total capacity of 1,560 MW. Both Units were placed in service in 1971.

Q. PLEASE DESCRIBE WHAT COMPRISES KENTUCKY POWER'S CONTRACTED GENERATION.

A. Kentucky Power was a party to a unit power agreement ("UPA") with AEP Generating Company for power from the Rockport Plant that terminated December 7, 2022. The Rockport Plant is located along the Ohio River in southern Indiana and consists of two supercritical pulverized coal-fired generating units. Kentucky Power's contractual share of the Rockport output totaled 393 MW. Upon termination of the Rockport UPA, the Company forecasted that it would require 152.4 MW of replacement capacity through the 2022/2023 PJM planning year ending May 31, 2023 that would be obtained through the PCA between Kentucky Power and AEP's Operating Companies.

Q. HAVE THE RETIREMENT DATES FOR BIG SANDY UNIT 1 OR MITCHELL GENERATING UNITS CHANGED?

A. There have been no changes to the expected retirement dates of either Big Sandy Unit 1 or the Mitchell Plant. With continued investment and maintenance, Big Sandy Unit 1 is expected to reach its current retirement date of 2031 and the Mitchell plant is expected to reach its retirement date of 2040. However, it is my understanding that, based on its recently filed Integrated Resource Plan, the Company is proposing to operate Big Sandy Unit 1 through 2041. Additionally, as a result of the Commission's Order in Case No. 2021-00004 denying a Certificate for Public Convenience and Necessity ("CPCN") for Effluent Limitation

Guidelines ("ELG") projects at Mitchell Plant, Kentucky Power's interest in Mitchell will terminate in 2028.

Q. PLEASE DESCRIBE THE KENTUCKY POWER GENERATING ASSETS THAT HAVE BEEN RETIRED.

A. Due to EPA's Mercury and Air Toxics ("MATS") Rule, Big Sandy Unit 2, an 800MW coal-fired generating asset, was retired in May 2015 and Big Sandy Unit 1 was converted from coal-fired to natural gas-fired in May 2016. The fuel conversion allowed Big Sandy Unit 1 to continue to operate in compliance with the stringent air emission requirements of MATS. There were coal-related assets for Big Sandy Unit 1 that were retired since they were not required for its natural gas operations.

Demolition activities at Big Sandy Unit 2 began in 2016. Since that time, the dismantlement of coal handling equipment and the demolition of its cooling tower, turbine building, boiler house, and environmental equipment have been completed. Currently, fly ash pond post-closure monitoring activities and asbestos abatement continue at the Big Sandy Plant. The going-forward coal-related decommissioning ARO costs associated with the fly ash pond and asbestos abatement for Big Sandy Unit 2 are identified by Company Witness Whitney.

Big Sandy Unit 1, although converted to a natural gas generating asset in 2016, had some equipment solely related to its operation as a coal-fired facility. Examples of Big Sandy Unit 1's coal-related assets included the coal yard and its associated equipment, the conveyors and silos which transferred coal from the coal yard to the plant, the coal pulverizers, the Electrostatic Precipitators ("ESP"), and the fly ash and bottom ash handling systems. This equipment was no longer necessary when the unit began operating as a natural gas unit and was retired once the unit no longer operated as a coal-fired facility.

V. KENTUCKY POWER GENERATION O&M

Q. WHAT ARE THE O&M REQUIREMENTS OF KENTUCKY POWER'S GENERATION ASSETS?

A. Kentucky Power's plants must provide safe, economical, and reliable generation output to serve load and accommodate fluctuating customer needs. In addition, a unit's maintenance needs vary based on its type, design, age, condition, and operational characteristics. All units are maintained to maximize operations, and to do so in a safe manner in compliance with all local, state, and federal regulations.

Q. HOW ARE O&M COSTS CONTROLLED AT THE PLANTS?

A. To minimize O&M expenses, Kentucky Power relies on a system of maintenance and operations management programs to ensure optimal performance of the generating assets. These maintenance programs are:

- Predictive Maintenance: monitoring, inspections, and/or data analyses conducted to diagnose potential maintenance issues early and usually while the equipment is running to minimize downtime.
- Preventive Maintenance: protocols, testing, and physical work conducted on equipment to address anticipated or diagnosed vulnerabilities.

In addition, continuous improvements are incorporated into the operations and maintenance of the generating units to eliminate waste and increase process efficiencies. Together, these maintenance and operations management programs help to optimize operation of the assets and limit O&M cost escalations.

Q. WHAT IS KENTUCKY POWER'S TEST YEAR LEVEL OF GENERATION O&M EXPENSE?

A. Kentucky Power's non-fuel, non-consumables, non-labor test year Generation O&M expense is $27.634 million. As shown in Figure TCK-2 below, Kentucky Power's test year Generation O&M expenses include steam maintenance and steam operations amounts for Big Sandy, the Company's 50% undivided interest in Mitchell, and shared plant costs not attributable to a specific generating unit (known as Non-Plant costs).

TCK-2: Test Year Kentucky Power Non-Fuel, Non-Consumables, Non-Labor Test Year Generation O&M*

Category	Big Sandy Plant	Mitchell Plant	Non-Plant	Total
Steam Maintenance	$5,954,613	$12,408,247	$212,067	$18,522,160
Steam Operations	$1,570,122	$4,911,699	$2,629,917	$9,111,737
Total:	$7,524,734	$17,319,946	$2,841,984	$27,633,897

*Total may not sum due to rounding

Q. DOES THE TOTAL AMOUNT OF $27.634 MILLION REPRESENT AN APPROPRIATE AND REASONABLE ONGOING LEVEL FOR O&M FOR KENTUCKY POWER'S GENERATION ASSETS?

A. Yes. This total level is reasonable and fairly reflects an appropriate level of O&M for Big Sandy and Kentucky Power's undivided 50% share of the Mitchell Plant.

VI. GENERATION CAPITAL ADDITIONS

Q. PLEASE PROVIDE AN OVERVIEW OF GENERATION CAPITAL ADDITIONS PLACED IN-SERVICE SINCE THE COMPANY'S LAST BASE CASE.

A. As shown in TCK-3 below, Kentucky Power had steam and other generation plant related capital additions totaling approximately $44.167 million placed in-service since the Company's last base case. Of that amount, $11.221 million is associated with major fossil fuel generation capital projects and $22.529 million that is associated with Production Plant Blanket ("PPB") capital projects.

Allocations to Kentucky Power's fossil fuel generation organization for intangible projects (information technology projects that are not associated with physical capital additions at Kentucky Power's plants but provide benefits to Kentucky Power) account for a combined total of approximately $11.551 million. General capital additions that support plant operations account for approximately $456 thousand. The remaining fossil fuel generation capital amounts include Asset Retirement Obligation ("ARO") estimates that resulted in a reduction of approximately $1.590 million to capital additions.

Figure TCK-3 is inclusive of all environmental project capital additions placed in-service since the last base case. However, all environmental project costs associated with ESP, Selective Catalytic Converter Reduction ("SCR"), and Dry Sorbent Injection ("DSI") capital additions are collected through Environmental Compliance Plan ("ECP") Company filings as discussed by Company Witness Kahn.

Figure TCK-3: Generation Capital Additions
April 2020 – March 2023

Plant	Project Description	Addition to Plant ($)
Big Sandy Plant	**Fossil Fuel Major Projects**	
	(Non-Environmental)	
	North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Physical Security Upgrade	$519,594
		$519,594
	(Environmental)	
	Repurpose Big Sandy Bottom Ash Pond (BAP)	$417,077
		$417,077
	Big Sandy Fossil Fuel Major Projects Sub-Total:	**$936,672**
	Other Fossil Generation Capital Projects	
	Production Plant Blanket Projects:	$5,811,279
	Non-Environmental	$5,808,906
	Environmental	$2,373
	ARO	$2,752,924
	Big Sandy Other Fossil Generation Capital Projects Sub-Total:	**$8,564,203**
Big Sandy Plant Total		**$9,500,875**
Mitchell Plant (Kentucky Power Share)	**Fossil Fuel Major Projects**	
	(Non-Environmental)	
	Mitchell Unit 2 Cooling Tower Components Replacement	$2,772,398
	Mitchell Unit 2 Air Heater Basket Replacement	$2,077,824
	Mitchell Unit 1 - Phase 2 Generator Step-up (GSU) Transformer Replacement	$13,416
		$4,863,638
	(Environmental)	
	Mitchell Unit 2 Electrostatic Precipitator (ESP)Upgrades	$2,115,185
	Mitchell Unit 1 Selective Catalytic Converter (SCR) Catalyst Layer 4 Replacement	$1,357,439
	Mitchell Unit 0 Dry Sorbent Injection (DSI) Lime Conversion	$1,326,811
	Mitchell Landfill Expansion -Phase 3	$587,858
	Mitchell Unit 1 SCR Catalyst Layer 3 Replacement	$27,976
	Mitchell Unit 2 - SCR Catalyst Layer 3 Replacement	$5,483
		$5,420,752
	Mitchell Fossil Generation Capital Projects Sub-Total:	**$10,284,390**
	Other Fossil Generation Capital Projects	
	Production Plant Blanket Projects	$16,718,190
	Non-Environmental	$13,365,463
	Environmental	$3,352,727
	ARO	($4,343,418)
	Mitchell Other Fossil Generation Capital Projects Sub-Total:	**$12,374,772**
Mitchell Plant Total		**$22,659,162**
Various Facilities	Intangible Capital Projects	$11,551,194
	General Capital Projects	$456,050
Various Facilities Total		**$12,007,244**
Total Kentucky Power Capital Additions		**$44,167,280**

Q. PLEASE SUMMARIZE INDIVIDUAL MAJOR FOSSIL FUEL GENERATION CAPITAL PROJECT ADDITIONS OVER $1 MILLION INCLUDED IN FIGURE TCK-3 AND EXPLAIN WHY THEY WERE NECESSARY.

A. A summary of individual major fossil fuel generation capital project additions over $1 million reflected in TCK-3 and associated necessities are summarized below.

Mitchell Major Capital Projects

Non-Environmental

- Mitchell Unit 2 Cooling Tower Components – Some of the Cooling Tower components had reached the end of their useful life after 30 years of service and some components had deteriorated to a point where they would not last another 5-years without failing. This project replaced the Hot Water Distribution deck, louvers and louver columns, outer periphery longitudinal girts, and other associated components.
- Mitchell Unit 2 Air Heater Basket Replacement –The air heater baskets were one year beyond their typical life cycle and were beginning to deteriorate exponentially. As a result, Mitchell Unit 2 was beginning to experience increases in its equivalent forced outage rate ("EFOR") associated with the baskets. The existing air heater baskets have been replaced with new air heater baskets.

Environmental

- Mitchell Unit 2 ESP Upgrades – Upgrades required to comply with particulate matter emission limits and the state of West Virginia 10% opacity limit. The scope of the project included:
  - the installation of a new heated purge air system;
  - repair and replacement of corroded ESP sidewall casing, hopper casing, and ductwork as needed;
  - removal and replacement of the hot and cold roof, including insulation, for approximately half of the precipitator;
  - replacement of the discharge electrode support insulators as needed;
  - repair of the collecting and discharge electrode rapper system; and
  - replacement of the hopper level detection system.
- Mitchell Unit 1 SCR Catalyst Layer 4 Replacement – 4th layer SCR catalyst replacement was required to maintain desirable NOx removal effectiveness. NOx emissions are subject to the New Source Review ("NSR") Consent

Decree and Cross-State Air Pollution Rule ("CSAPR"). The catalyst layer replacement will also maintain effective mercury oxidation across the SCR catalyst reactor.

- Mitchell Units 0 DSI Lime Conversion Project – Mitchell Plant currently uses Trona for SO_3 mitigation. The project reconfigured the existing DSI system for Mitchell Units 1 and 2 to more efficiently handle hydrated lime in lieu of Trona, and reduce issues related to corrosion, as well as gain benefits such as heat rate improvement, improved Equivalent Unplanned Outage Rate ("EUOR"), and a lower minimum load. Conversion to lime also allows for the use of a higher percentage of high sulfur coal which has historically been cheaper than the lower sulfur coal, thereby resulting in lower overall fuel costs. The project also installed a new distributed control system for the DSI.

Q. WHAT ARE PPB PROJECTS?

A. PPB projects are capital projects necessary to provide for the safe, environmentally responsible, reliable, and efficient operation of our generating units. They are sometimes referred to as 'Maintenance Capital' projects. These projects are placed into two categories, major or minor. Major plant blanket projects will have a total cost of over $1,000,000, but under $3,000,000. Minor plant blanket projects, the vast majority of which are smaller component replacements and installations, are projects that have a total cost of under $1,000,000.

When evaluating these PPB projects, Kentucky Power looks for cost savings whenever possible without jeopardizing reliability and safety. All PPB projects over $1 million are also reviewed and approved through AEPSC's Strategic Capital Prioritization Process ("SCPP") which includes review and approval by AEP's Vice President (VP) of Project Solutions, VP of Engineering

Service, VP of Generation Shared Services, VP of Appalachian Power Company/ Wheeling Power Company Generating Assets, and VP of Southwestern Power Company Generating Assets.

Q. PLEASE DESCRIBE SOME OF THE PPB CAPITAL ADDITIONS OVER $1 MILLION SINCE THE LAST BASE CASE AT KENTUCKY POWER PLANTS.

A. The major PPB projects for the Big Sandy and Mitchell Plants are listed below:

Big Sandy Major PPB Capital Projects

- Big Sandy Unit 1 Generator Stator Re-wedge – The generator stator was last re-wedged in 2008 and upon inspection in fall 2022, it was determined the stator required another re-wedge in order to mitigate the potential risk of a premature stator failure and thereby enhance the reliability of the generator. A stator failure would have left the Unit in a forced state of being unable to operate for a period of one year or more due to long lead time materials.

Mitchell Plant Major PPB Capital Projects

- Mitchell Unit 2 SCR Catalyst Layer 4 Replacement – Need for the replacement of the catalyst 4th layer was due to normal deactivation over thousands of hours of run time. SCR NOx removal effectiveness requires adequate activity levels. SCR NOx performance is required for compliance with the NSR Consent Decree requirements and CSAPR regulations.

Q. PLEASE SUMMARIZE THE INTANGIBLE CAPITAL INVESTMENTS

A. Intangible capital projects are routine software updates and new programs that increase the efficiency of Kentucky Power's Generation organization.

Q. ARE EXPENSES RELATED TO ELG COMPLIANCE AT MITCHELL INCLUDED UNDER PPB PROJECTS OR INCLUDED IN O&M EXPENSES?

A. No. As I stated earlier in my testimony, this Commission did not approve the CPCN to execute ELG projects required by EPA to comply with its revisions to the ELG rule effective October 2020 at the Mitchell Units; therefore, Kentucky Power is not authorized to recover costs related to ELG compliance projects at Mitchell.

Q. HOW DOES THE COMPANY ENSURE ELG-RELATED COSTS ARE NOT CHARGED TO KENTUCKY POWER SINCE THIS COMMISSION ONLY APPROVED COAL COMBUSTION RESIDUALS ("CCR") PROJECT UPGRADES?

A. Pursuant to the September 1, 2022 Written Consent Action of the Mitchell Operating Committee, which is included as Exhibit V of Section II of the Company's Application, the Company hired Burns & McDonnell, an independent engineering, architecture construction, environmental consulting firm, to perform an assessment of the scope of work directly related to the CCR and ELG projects for the purpose of determining the appropriate allocation of CCR and ELG related costs. As a result of and in accordance with Burns & McDonnell's assessments, the Company established work orders to ensure costs related to the scope of work for each of the CCR and ELG projects are appropriately charged.

VII. GENERATION PERFORMANCE DURING WINTER STORM ELLIOTT

Q. PLEASE DESCRIBE WINTER STORM ELLIOTT.

A. As explained further by Company Witness Vaughan, Winter Storm Elliott was a bomb cyclone[1] that impacted the PJM region from December 23, 2022 through December 27, 2022 (the "Winter Storm Elliott Period"), causing extreme cold weather, including blizzards, high winds, and snow.

Q. WERE THE COMPANY'S GENERATION ASSETS AVAILABLE AND OPERATING DURING THE WINTER STORM ELLIOTT PERIOD?

A. Both Mitchell Unit 1 and Unit 2 (collectively, the "Mitchell Units") were available and operating throughout the Winter Storm Elliott Period. As shown in Exhibit TCK-1, Mitchell Unit 1 had a Net Capacity Factor[2] ("NCF") of 80.3% and Mitchell Unit 2 had an NCF of 74.1% during the Winter Storm Elliott Period. Big Sandy Unit 1 was in a Planned Outage and was unavailable.

Q. HOW DOES THE MITCHELL PLANT PREPARE FOR WINTER?

A. In preparation for winter, the Mitchell Plant implements a "Winter Preparedness Plan." In 2022, the plant implemented the "Winter Preparedness Plan" starting on October 3, 2022. The standard plan included employee training, completing preventative maintenance work orders, performing equipment checks, replenishing supplies, and other winter preparedness activities. Plant personnel completed a cold weather site specific plan review on October 19, 2022 and completed training on the North American Electric Reliability Council cold weather reliability standards

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[1] A bomb cyclone is a large, intense storm that rapidly intensifies and is defined by a sudden and significant drop in atmospheric pressure.

[2] Net Capacity Factor is defined as the ratio of the generating unit's ((net actual generation) to its net maximum capacity for the number of hours in the period being reported that the unit was in the active state) x 100%.

by October 31, 2022. Cold Weather Preparedness and Winterization checks conducted as preventative maintenance activities were completed by November 2, 2022.

Q. DID THE MITCHELL PLANT TAKE ANY ADDITIONAL PREPARATORY STEPS IN ADVANCE OF WINTER STORM ELLIOTT?

A. Yes. In anticipation of Winter Storm Elliott, Mitchell Plant staffing was increased to at least one on-site member from the plant leadership team and additional plant operations personnel and contractor support were brought on site.

Q. HOW DID THE MITCHELL UNITS PERFORM DURING WINTER STORM ELLIOTT?

A. Both Mitchell Units performed well during the Winter Storm Elliott Period. Both Units had a 0% forced outage factor[3] and 0% maintenance outage factor[4], meaning at no point during the event were either of the Mitchell Units unavailable.

Q. WAS EITHER UNIT'S OUTPUT REDUCED (OR DERATED) DURING WINTER STORM ELLIOTT?

A. Yes, at times, both Mitchell Units experienced derates due to operational issues. A "derate" is defined as a decrease in the available capacity of an electric generating unit, commonly due to a system or equipment modification or environmental, operational, or reliability considerations. As demonstrated in Exhibit TCK-1, a significant portion of the derates experienced at both Mitchell Units were required to comply with particulate matter emission limits and the state of West Virginia's

[3] Forced outage factor is the ratio of ((All hours experienced during forced outages) to the number of hours in the period being reported that the unit was in the active state) x 100%.
[4] Maintenance outage factor is the ratio of ((All hours experienced during maintenance outages) to the number of hours in the period being reported that the unit was in the active state) x 100%.

10% opacity limit. The opacity-related derates were not driven by Winter Storm Elliott. Mitchell Unit 1 also had a small 35 MW derate related to a boiler clinker for the duration of the Winter Storm Elliott Period.

The remaining derates were caused by frozen coal causing the coal conveyor to trip out, freezing of slurry feed tanks, and a pulverizer damper operation issue. This group of derates lasted a combined total of only 20.31 of the 240 hours of operation between both Mitchell Units during the Winter Storm Elliott Period.

During Winter Storm Elliott, Unit 1 had an equivalent availability factor[5] ("EAF") of 86.3%, and Unit 2 had an EAF of 78.4%.

Q. HOW DOES THE MITCHELL PLANT'S PERFORMANCE DURING WINTER STORM ELLIOTT COMPARE TO ITS HISTORICAL PERFORMANCE?

A. Both Mitchell Units performed favorably during Winter Storm Elliott as compared to their historic performance, as Figure TCK-4 demonstrates.

[5] Equivalent Availability factor is the ratio of ((Available hours – equivalent planned derated hours – equivalent unplanned derated hours – equivalent seasonal derated hours) to the number of hours in the period being reported that the unit was in the active state) x 100%.

Figure TCK-4: Mitchell Unit Performance:
Winter Storm Elliott Period Compared to 2016-2021

Mitchell Unit	Winter Storm Elliott Period Net Capacity Factor (“NCF”)	Average NCF (2016-2021)	Highest NCF (2016-2021)	Winter Storm Elliott Period Average Availability Factor (“EAF”)	Average EAF (2016-2021)	Highest EAF (2016-2021)
Unit 1	80.3%	36.9%	52.%	86.3%	57.1%	68.1%
Unit 2	74.1%	46.6%	65.8%	78.4%	69.3%	84.4%

As demonstrated above, Unit 1’s NCF and EAF and Unit 2’s NCF during the Winter Storm Elliott Period were higher during Winter Storm Elliott that their 6-year highest annual levels. Both Units’ NCF and EAF during the storm period far exceeded their 6-year averages.

Q. COULD THE COMPANY REASONABLY HAVE DONE ANYTHING DURING THE WINTER STORM ELLIOTT PERIOD TO INCREASE THE OUTPUT OF THE MITCHELL GENERATING FACILITIES?

A. No. Again, it is important to reiterate that, although the Mitchell Units were derated during Winter Storm Elliott, at no point was either Mitchell Unit unavailable to serve customers. Furthermore, the Company cannot legally operate the Mitchell Units in a manner that would violate the particulate matter emission limits and the state of West Virginia’s 10% opacity limit. The remaining non-opacity related derates were short in duration but were required to allow for the necessary repairs to be made while keeping the Units available. As such, when both Mitchell Units were needed during this extreme event, they were available and performed well, to the benefit of Kentucky Power customers.

Q. PLEASE DESCRIBE THE PLANNED OUTAGE AT BIG SANDY DURING WINTER STORM ELLIOTT.

A. Big Sandy Unit 1 began a Planned Outage on September 9, 2022. The outage was originally scheduled to be completed on December 4, 2022, but had to be extended several times through January 14, 2023 for a number of reasons including additional time required to repair the generator due to hot spots in the core, replacement of the generator rotor collector end retaining ring due to a crack discovered during the outage, the repair of the hydrogen seal housing at the exciter due to a leak, and the need to repair an unexpected condenser leak identified at start-up. The extensions to the outage were necessary to repair and/or replace generator components to prevent the risk of a catastrophic failure of the generator as well repair the condenser to allow the Unit to restart and avoid future forced outages. The timeline for the Company's outage extension request to PJM is discussed later in my testimony. Each extension for the Big Sandy fall 2022 outage was approved by PJM.

Q. WHAT IS A PLANNED OUTAGE?

A. A Planned Outage is a generating unit outage of a predetermined duration that can last for several weeks and occurs only once or twice a year. Typically, these events consist of a known scope of work and duration that is estimated prior to the outage being scheduled.

Q. HOW ARE PLANNED OUTAGES SCHEDULED?

A. Planned Outages are scheduled well in advance (months and sometimes even years) due to significant scope, equipment lead time, engineering, and time out of operation. Such outages are planned in conjunction with PJM and with PJM's approval. The Company schedules Planned Outages during the shoulder months attempting to avoid, to the extent practical, multiple units simultaneously in a Planned Outage.

Q. WHEN A UNIT IS IN A PLANNED OUTAGE, IS IT POSSIBLE TO QUICKLY RETURN THE UNIT TO SERVICE IF MARKET CONDITIONS CHANGE?

A. Generally, it is not. During a Planned Outage, a generating unit is often at least partly dismantled, often with pressure parts (parts that contain steam at very high pressures and temperatures when operating, such as boilers, turbines, etc.) taken apart to be inspected, maintained, and/or replaced. It is very difficult if not impossible to safely and quickly return a unit to service or deviate from the work plan for the outage, particularly when major equipment is disconnected or dismantled for repair at that time.

Q. PLEASE DESCRIBE THE SCOPE OF WORK THAT WAS TO BE COMPLETED DURING THE PLANNED OUTAGE AT BIG SANDY UNIT 1.

A. As originally scoped, the fall 2022 Planned Outage at Big Sandy Unit 1 included a generator field out inspection and a possible re-wedge of the Unit's stator.[6] The Company was, in fact, required to completely re-wedge the stator as part of this scope of work.

[6] The stator is the stationary part of a rotary system found in electric generators. In an electric generator, the stator converts the rotating magnetic field to electric current.

Q. WHY DID BIG SANDY'S OUTAGE EXTEND BEYOND ITS PLANNED OUTAGE END DATE?

A. In November 2022, the Company extended the Planned Outage at Big Sandy Unit 1 to December 12, 2022, as it needed additional time to complete the original scope of work. Then, on November 13, 2022, the Company discovered a crack on the generator rotor collection end retaining ring and determined that the retaining ring required replacement prior to returning the Unit to service. In order to complete that repair, on December 2, 2022, the Company requested the Planned Outage at Big Sandy Unit 1 be extended through December 30, 2022. PJM approved the extension on December 6, 2022. The Planned Outage was extended twice more for a hydrogen seal leak identified during an air leakage test and a condenser leak discovered during start up. These extensions were requested on December 22, 2022, and January 10, 2023, and were approved by PJM on December 28, 2022, and January 11, 2023, respectively.

Q. COULD THE COMPANY HAVE PLACED BIG SANDY UNIT 1 IN SERVICE WITHOUT ADDRESSING THE ITEMS THAT CAUSED THE PLANNED OUTAGE TO BE EXTENDED THROUGH THE WINTER STORM ELLIOTT PERIOD?

A. No, it could not. First, as explained further above, extending the outage to replace the retaining ring extended the Planned Outage through what became the Winter Storm Elliott Period. If the Company had not replaced that retaining ring, Big Sandy Unit 1 would have been at an increased risk of catastrophic failure. Therefore, the Company could not have safely placed the Unit back in service and operated it without replacing the retaining ring. It likewise could not have put the Unit safely back in service without fixing the hydrogen seal and condenser leaks.

Q. WAS THERE ANY WAY FOR THE COMPANY TO HAVE KNOWN ABOUT THE WINTER STORM ELLIOTT EVENT WHEN IT REQUESTED THE PLANNED OUTAGE EXTENSION ON DECEMBER 2, 2022.

A. No.

Q. WERE THE COMPANY'S ACTIONS RELATED TO EXTENDING THE BIG SANDY UNIT 1 OUTAGE REASONABLE?

A. Yes. The Company could not have brought Big Sandy Unit 1 back online to serve customers during Winter Storm Elliott without risking a catastrophic failure of the Unit as all the repairs described above were required to be completed in order to safely operate the Plant. Therefore, it was reasonable to extend the planned outage to ensure the Unit would be in good working order to service customers into the future.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Timothy C. Kerns, being duly sworn, deposes and says he is the Vice President of Generating Assets, for Appalachian Power Company and Wheeling Power Company, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Timothy C. Kerns

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Timothy C. Kerns, on June 27, 2023.

Scott E. Bishop
Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

DATA REQUEST

KPSC 1_6 Provide a detailed explanation of how Kentucky Power's generating units were operating during Winter Storm Elliott. Include in the response a list and event description in chronological order showing by unit and date any scheduled, actual, and forced outage for the months of November and December 2022.

RESPONSE

Winter Storm Elliott began in the Pacific Northwest on December 20, 2022 and moved east at a rapid pace becoming a bomb cyclone, an area of low pressure that intensifies rapidly, and entering the PJM territory on December 23, 2022. Winter Storm Elliott impacted the PJM territory from December 23, 2022 until December 27, 2022. During that period, none of the Company's generating units were forced from service.

Big Sandy Unit 1 was in its Planned Outage (9/9/22 – 1/14/23) which was extended from its planned end date of 12/12/2022 due to emergent generator repair work discovered during its reassembly. The completion of this work was required so the unit could be returned to service and operated safely and reliably.

Both Mitchell units operated continuously throughout the Winter Storm Elliott period (12/23/2022 – 12/27/2022). At times during that period, each of units' output was reduced (or derated) due to operational issues. Those deratings resulted in Net Capacity Factors (NCF) of 80.3% and 74.1% for Units 1 and 2, respectively and were largely unrelated to the extreme weather.

Table 1 below describes the performance of the Company's generating units during the period.

Kentucky Power Company
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Table 1. KPCo Unit Performance During the 5 day Winter Storm Elliott Period (12/23/2022 - 12/27/2022)

	Equivalent Forced Outage Rate (EFOR)	Equivalent Availability Factor (EAF)	Net Capacity Factory (NCF)
Big Sandy Unit 1	0.0%	0.0%	0.0%
Mitchell Unit 1	13.7%	86.3%	80.3%
Mitchell unit 2	21.6%	78.4%	74.1%

Performance Metric Definitions
Equivalent Forced Outage Rate (EFOR)[1] - The ratio of unit's forced outage hours + derates to the its forced outage hours + service hours expressed as a percentage.
Equivalent Availability (EAF)[1] - The ratio of the unit's available hours - all derate hours to the number of hours in the period.
Net Capacity Factor (NCF)[1] - The ratio of the unit's net generation to it maximum potential output for the period.
[1] Formal definitions and equations for performance metrics can be found in the ***NERC 2023 Data Reporting Instructions - Appendix F***

Attachment KPCO_R_KPSC_1_6_Attachment1 lists the curtailing (derating) events for the period by unit and in chronological order.

Attachment KPCO_R_KPSC_1_6_Attachment2 lists the forced, maintenance and planned outages in chronological order for the months of November and December 2022.

Witness: Robert A. Jessee

	Event Type Code *								
Unit Name	Outages	Curtail.	Event Start	Event End	Event Description	MW Reduction	Period Elapsed Loss (MWH)	Event Number	Event Elapsed Time (Hours)
Big Sandy 1	PO		09/09/22 11:00 PM	01/14/23 11:47 AM	Boiler i/r, Generator Field Out inspection/possible rewedge, Turbine Valve i/r, Corrosion Fatigue i/r, Cooling Tower i/r, ReHeat Attemperator i/r, Gas valve i/r, FD Fan and Motor i/r, High Energy Piping (HEP) i/r, Flow Accelerated Corrosion (FAC) i/r, Core Loop testing.	295	35,448	71	119.98
Mitchell 1		D3	12/22/22 12:00 AM	12/30/22 12:00 AM	Large clinker growing on North side of Boiler	35	4,200	948	119.98
Mitchell 1		D1	12/24/22 06:48 AM	12/24/22 07:06 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	465	140	949	0.30
Mitchell 1		D1	12/24/22 07:06 AM	12/24/22 07:43 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	97	60	950	0.62
Mitchell 1		D1	12/24/22 07:43 AM	12/24/22 08:20 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	465	287	951	0.62
Mitchell 1		D1	12/24/22 08:20 AM	12/24/22 12:00 PM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	140	514	952	3.67
Mitchell 1		D1	12/24/22 01:48 PM	12/24/22 07:34 PM	Opacity	80	462	953	5.77
Mitchell 1		D1	12/24/22 07:34 PM	12/25/22 09:00 AM	Opacity	90	1,210	954	13.43
Mitchell 1		D1	12/25/22 10:07 AM	12/25/22 12:31 PM	Frozen lumps of coal causing conveyor trip out outs	135	324	955	2.40
Mitchell 1		D1	12/26/22 12:20 AM	12/26/22 08:29 AM	Opacity	45	368	956	8.15
Mitchell 1		D1	12/26/22 08:29 AM	12/26/22 08:46 AM	Opacity	60	17	957	0.28
Mitchell 1		D1	12/26/22 08:46 AM	12/27/22 12:00 AM	Opacity	85	1,296	958	15.23
Mitchell 1		D3	12/27/22 12:00 AM	12/27/22 01:40 AM	Opacity	85	142	959	1.67
Mitchell 1		D3	12/27/22 01:40 AM	12/27/22 02:02 AM	Opacity	135	50	960	0.37
Mitchell 1		D3	12/27/22 02:02 AM	12/27/22 02:53 AM	Opacity	155	132	961	0.85
Mitchell 1		D3	12/27/22 02:53 AM	12/27/22 04:43 AM	Opacity	185	339	962	1.83
Mitchell 1		D3	12/27/22 04:43 AM	12/27/22 07:22 AM	Opacity	205	544	963	2.65
Mitchell 1		D3	12/27/22 07:22 AM	12/27/22 11:03 AM	Opacity	235	866	964	3.68
Mitchell 1		D3	12/27/22 11:03 AM	12/28/22 12:00 AM	Opacity	245	3,174	965	12.93
Mitchell 2		D1	12/23/22 10:10 AM	12/23/22 10:28 AM	25 Pulv issue	95	29	908	0.30
Mitchell 2		D1	12/23/22 10:28 AM	12/23/22 05:44 PM	25 Pulv issue, could not get dampers to operate	90	654	910	7.27
Mitchell 2		D1	12/23/22 12:07 PM	12/23/22 01:56 PM	Opacity	25	46	909	1.82
Mitchell 2		D1	12/23/22 01:56 PM	12/23/22 02:53 PM	Opacity	50	48	913	0.95
Mitchell 2		D1	12/23/22 02:53 PM	12/23/22 07:22 PM	Opacity	100	448	914	4.48
Mitchell 2		D1	12/23/22 07:22 PM	12/23/22 09:08 PM	Opacity	90	159	915	1.77
Mitchell 2		D1	12/23/22 09:08 PM	12/24/22 02:46 AM	Opacity	150	845	916	5.63
Mitchell 2		D1	12/24/22 02:46 AM	12/24/22 04:41 AM	Opacity	90	173	917	1.92
Mitchell 2		D1	12/24/22 04:41 AM	12/24/22 02:08 PM	Opacity	75	709	918	9.45
Mitchell 2		D1	12/24/22 06:48 AM	12/24/22 07:08 AM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	415	138	911	0.33
Mitchell 2		D1	12/24/22 07:08 AM	12/24/22 12:00 PM	Reagent slurry feed tanks have frozen level indications and tanks were lower than expected	210	1,023	912	4.87
Mitchell 2		D1	12/24/22 02:08 PM	12/25/22 12:00 AM	Opacity	90	888	919	9.87
Mitchell 2		D3	12/25/22 12:00 AM	12/26/22 12:00 AM	Anticipated opacity	190	4,565	920	24.00
Mitchell 2		D3	12/26/22 12:00 AM	12/27/22 12:38 PM	Opacity	190	6,968	921	36.63
Mitchell 2		D3	12/27/22 12:38 PM	12/27/22 02:02 PM	Opacity	210	294	923	1.40
Mitchell 2		D3	12/27/22 02:02 PM	12/27/22 03:12 PM	Opacity	230	268	924	1.17
Mitchell 2		D3	12/27/22 03:12 PM	12/27/22 04:08 PM	Opacity	340	317	925	0.93
Mitchell 2		D3	12/27/22 04:08 PM	12/28/22 11:40 PM	Opacity	365	2,871	926	7.85

Event Type *
Outages

FO	Forced Outage
MO	Maintenance Outage
PO	Planned Outage
RS	Reserve Shutdown
SF	Startup Failure
Note:	i/r = inspection and repair

Curtailment

D1	Requires immediate reduction in capacity
D2	Does not require an immediate reduction in capacity but requires a reduction within six (6) hours
D3	Can be postponed beyond six (6) hours, but requires reduction in capacity before the end of the next weekend

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Unit Name	Event Type *	Event Start	Event End	Event Description
Big Sandy 1	PO	09/09/22 11:00 PM	01/14/23 11:47 AM	Boiler i/r, Generator Field Out inspection/possible rewedge, Turbine Valve i/r, Corrosion Fatigue i/r, Cooling Tower i/r, ReHeat Attemperator i/r, Gas valve i/r, FD Fan and Motor i/r, High Energy Piping (HEP) i/r, Flow Accelerated Corrosion (FAC) i/r, Core Loop testing.
Mitchell 1	PO	10/07/22 11:00 PM	11/19/22 05:32 PM	Boiler i/r, Precip i/r, Pulverizer/Feeder MATS i/r, Economizer wash, Replace Precip Transformer power cables, Replace SCR XJ s 14,15 and 115, Replace Exit Duct XJ FGX-71009, Water Cannon upgrades, Ovation Evergreen upgrade, Inter-lock testing, HE Piping i/r.
Mitchell 1	RS	11/19/22 05:32 PM	11/29/22 11:45 AM	Reserve Shutdown
Mitchell 1	SF	11/29/22 11:45 AM	11/29/22 06:03 PM	Unable to get firing permissives.
Mitchell 1	MO	12/03/22 01:47 AM	12/08/22 09:18 AM	Economizer tube leak repair
Mitchell 1	FO	12/08/22 11:45 AM	12/09/22 12:00 AM	PH Issues
Mitchell 1	FO	12/09/22 12:00 AM	12/10/22 08:01 AM	due to Urea from Hydrolyzer system entering the Condensate Return System. Samples will be collected and tested once the unit cools. Hydrolyzer will need pressurized to search for potential leaks.
Mitchell 1	FO	12/10/22 01:07 PM	12/13/22 04:30 PM	Due to Primary Superheater Outlet valve . packing blew out. Superheater Bypass Control valve URV 4, controller failed closed due to burned up controller.
Mitchell 1	RS	12/13/22 04:30 PM	12/14/22 02:45 AM	Reserve Shutdown
Mitchell 1	SF	12/14/22 02:45 AM	12/14/22 07:15 PM	Start Failure
Mitchell 1	MO	12/30/22 12:00 AM	01/22/23 05:59 PM	Boiler i/r, Boiler Hydro, Duct repairs, Clinker Removal, IK Soot Blower Repairs, 12 ID Fan Stall margin probe i/r.
Mitchell 2	PO	09/09/22 11:00 PM	12/16/22 02:25 PM	Boiler i/r, Cooling Tower i/r, Low Pressure Turbine "A"&"B" Valve replacement, SCR Catalyst #4 layer replacement, AH Basket i/r, Precip i/r.
Mitchell 2	PO	12/16/22 02:52 PM	12/16/22 03:28 PM	Boiler i/r, Cooling Tower i/r, Low Pressure Turbine "A"&"B" Valve replacement, SCR Catalyst #4 layer replacement, AH Basket i/r, Precip i/r.
Mitchell 2	FO	12/17/22 02:12 PM	12/20/22 04:08 PM	A Bus Relay PA Fan

Event Type *

FO	Forced Outage
MO	Maintenance Outage
PO	Planned Outage
RS	Reserve Shutdown
SF	Startup Failure
Note:	i/r = inspection and repair

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
ALEX E. VAUGHAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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DIRECT TESTIMONY OF
ALEX E. VAUGHAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Alex E. Vaughan. I am employed by AEPSC as Managing Director-Renewables & Fuel Strategy. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the RTO Settlements Group. I later became the PJM Settlements Lead Analyst, and in that role, I was responsible for reconciling AEP's settlement of its activities in the PJM Interconnection, LLC ("PJM") market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing and Analysis, where I was responsible for cost of service, rate design, and special contract analysis for the AEP east operating companies. In September 2018, I was promoted to Director of Regulated Renewables and Pricing, at which time oversight of regulated renewable and fuel filings across the AEP operating companies was added to my responsibilities. I was promoted to my current position in June 2022.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. I am responsible for assisting Kentucky Power and the other AEP electric utility operating companies in the preparation of their regulatory filings before this and other commissions under whose jurisdiction these companies provide electric service. My responsibilities include the oversight of cost of service analyses, rate design, special contracts, energy supply costs, and renewables for the AEP System operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have presented testimony on behalf of the AEP operating companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky, Tennessee, Indiana, Michigan, and Oklahoma. In Kentucky, I have testified before the Kentucky Public Service Commission (the "Commission") in several cases, most notably in Kentucky Power's past four base rate case proceedings (Case Nos. 2013-00197, 2014-

00396, 2017-00179, and 2020-00174), and the proposed transfer of ownership of Kentucky Power in Case No. 2021-00481.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is threefold:

- To support the prudence of the approximately $11.5 million winter storm Elliott Peaking Unit Equivalent ("PUE") purchased power expense and $3.2 million of other PUE expense Kentucky Power incurred during the test year;
- To describe and outline the Company's proposed financial power hedging framework for which it is seeking approval; and
- To describe and support the Company's proposed distributed solar program.

IV. PUE EXPENSE

Q. PLEASE DESCRIBE THE SITUATION THAT CAUSED THE APPROXIMATELY $11.5 MILLION WINTER STORM ELLIOTT PUE EXPENSE.

A. Winter Storm Elliott ("Elliott") was an extreme cold weather event that included blizzards, high winds, snowfall and record cold temperatures across much of the United States. Elliott occurred December 23, 2022 through December 26, 2022, in the PJM region (the "Winter Storm Elliott Period").[1] The resulting load during this period of time was an extreme outlier in both magnitude and timing, with the Christmas Eve load

[1] PJM defined the Winter Storm Elliott Period as December 23, 2022 through December 26, 2022, and this is the time period used for purposes of this testimony. The Company also has referred to the Winter Storm Elliott Period when describing its generation performance as December 23, 2022 through December 27, 2022 (see Direct Testimony of Timothy C. Kerns).

being 40 gigawatts ("GW") higher than the second highest in the past decade.[2] The drastic temperature drop and higher than forecasted load caused PJM to dispatch generation reserves, many of which failed to perform.

The unanticipated high load and rapid load increase combined with generation outages due to cold weather and fuel issues resulted in Performance Assessment Intervals ("PAIs") on December 23, 2022 and December 24, 2022. PAIs are triggered when PJM declares an emergency action in the RTO. During the PAIs, the load weighted LMP reached the system marginal price cap of $3,700/MWh as a result of the supply/demand imbalance during emergency operations. Generation resource outages during Elliott peaked at 48,080 MW on December 24, 2022. Roughly 11,000 MW of those outages were due to a lack of natural gas supply.[3]

Q. DID THE COMPANY EXPERIENCE EXTREME LOAD CONDITIONS DURING ELLIOTT?

A. Yes. The Company's peak load during the Winter Storm Elliott Period was 1,358 MW, 46% higher than the Company's previous 12 month average peak demand ("12CP") of 929 MW. In 85 of the 96 hours during the event, the Company's hourly average load was higher than its most recent 12CP demand.

[2] https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx

[3] PJM State of the Market Report 2022 – pages 210-211.

Figure AEV-1

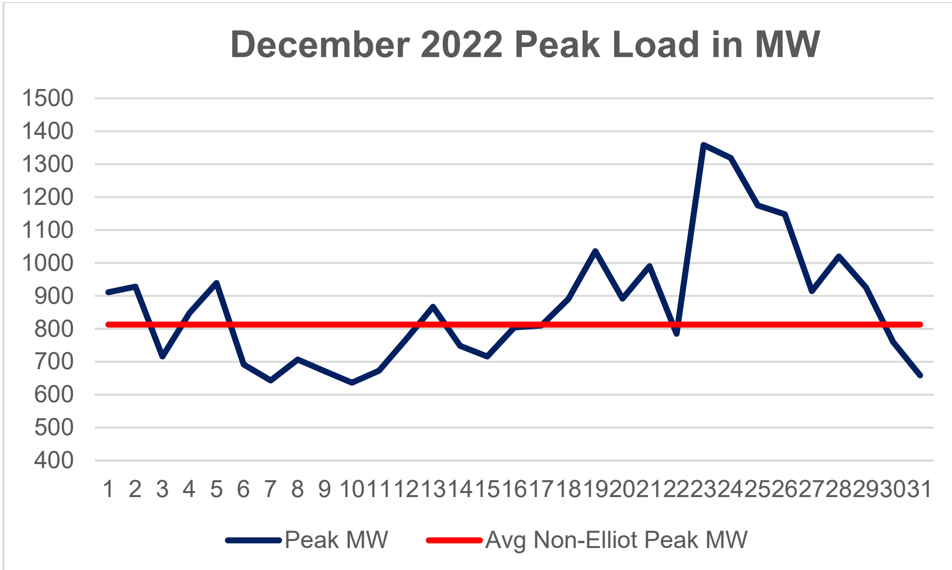


Figure AEV-1 illustrates the Company's daily peak demand during the month of December 2022. As can be seen, there is an extreme increase in demand during Elliott, including the 1,358 MW peak during hour ending 2100 on December 23, 2022. The flat line in Figure AEV-1 is the average peak demand during the non-Elliott days in December (813 MW). The Company's peak demand during Elliott was 545 MW higher than the average peak demand for the other 27 days of December 2022. Before this, one has to go back to January 2018 to find a Company peak higher than what was experienced during Elliott, and the Company has only had eight monthly peaks in the last decade greater than the Elliott peak. This illustrates the magnitude of the demand on the Company's system resulting from Elliott's extreme cold weather. This high load when combined with PJM-wide emergency operations resulted in extremely high system energy pricing at which the Company had to purchase its load obligation, in excess of its available supply, from the PJM spot energy market. Figure AEV-2 below shows the real-time LMPs over the Winter Storm Elliott Period, and Figure AEV-3 shows real-time LMPs over the month of December 2022 to put into context how much of an outlier pricing during Elliott was and provide a narrower view on the hourly pricing during Elliott.

Figure AEV-2

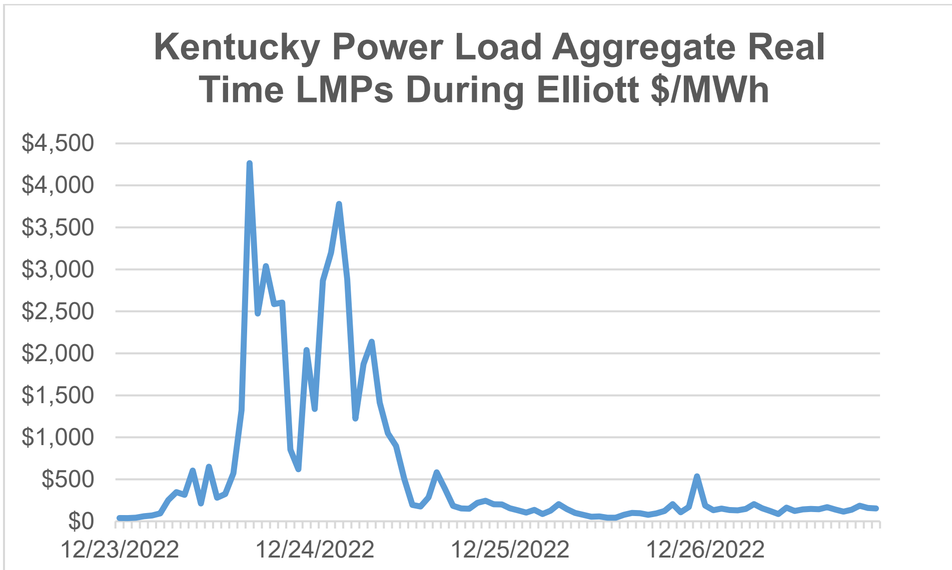
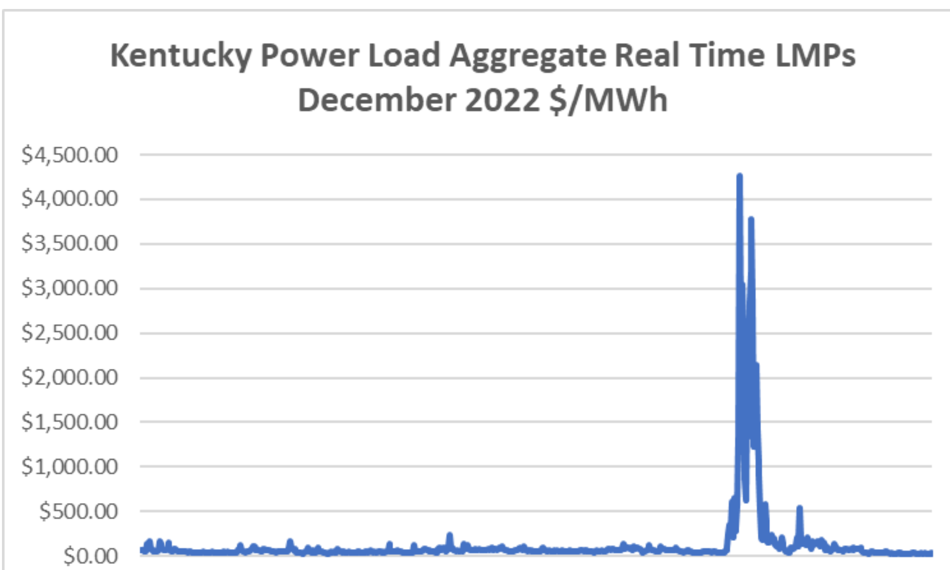


Figure AEV-3



Q. HOW DID THE COMPANY'S GENERATION RESOURCES PERFORM DURING THE WINTER STORM ELLIOTT EVENT?

A. During Elliott, none of the Company's generating units were forced out of service. Both Mitchell Units operated continuously throughout Elliott. Mitchell Units 1&2 operated at 80.31% and 74.11% net capacity factors,[4] respectively. The Mitchell Units performed at a level above the total PJM coal fleet which achieved a net capacity factor of 73.03%[5] during the same period of time. Big Sandy Unit 1 was in the midst of a PJM-approved planned outage during Winter Storm Elliott. Company Witness Kerns provides a more detailed description of the performance of the Company's generation resources during the Winter Storm Elliott Period.

Q. HAD THE COMPANY'S GENERATION RESOURCES RUN AT A 100% CAPACITY FACTOR DURING THE WINTER STORM ELLIOTT PERIOD, WOULD THERE STILL HAVE BEEN A NEED TO PURCHASE ENERGY FROM THE PJM SPOT ENERGY MARKET?

A. Yes. The Company's generation resources at 100% of their installed capacities ("ICAP") can produce approximately 1,076 MWh. As discussed earlier, the Company's load was extremely high during Elliott because of the extreme cold. In many instances, the Company's customers rely on electricity for heating their homes, which caused extremely high load conditions during Elliott. Thus, even had the Company's generators run at 100% of their ICAPs, the Company would have still

[4] December 23-27 period to be consistent with Company Witness Kerns's testimony.
[5] Source: PJM Dataminer2 and PJM State of the Market Report for 2022.

purchased roughly 8,400 MWh from the PJM spot market during the Winter Storm Elliott Period.

Q. DID THE COMPANY INCUR A CAPACITY PERFORMANCE PENALTY DURING THE ELLIOTT PAIs?

A. No, due to the Company's prudent management of its available coal supplies during 2022, the Mitchell Plant was available to run and, as previously discussed, operated continuously during Elliott and the PAIs called by PJM. Furthermore, the larger AEP Companies FRR plan, in which Kentucky Power participates, also did not incur a penalty as it benefited from the diversity of generation resource types and locations utilized by the Companies in the plan.

Q. WHAT OTHER OPTIONS WERE AVAILABLE TO THE COMPANY DURING THE WINTER STORM ELLIOTT EVENT TO SERVE THE HOURLY ENERGY NEEDS OF ITS CUSTOMERS?

A. The Company had to purchase power from the PJM spot energy market during Elliott because the Company's load obligations were in excess of the supply available from its resources. The Company's plan for covering load obligations in excess of available generation supply is to purchase the balance of its energy requirements from the PJM spot energy markets. The Company's customers receive the lower of cost to generate or market energy prices as determined by PJM's FERC approved tariff and economic dispatch model. To the extent that the Company may be adding additional owned or contracted capacity and energy resources in the future to replace the energy and capacity from the recently expired Rockport Unit Power Agreement ("UPA"), those resources would contribute in the future to reducing the Company's amount of spot market energy purchases from PJM. However, it should be noted that resource acquisitions are generally informed by long-range integrated resource planning and forecasting that utilizes normative forecasts that do not account for extreme outlier events like Elliott. The weather and resulting conditions in the PJM energy market during Elliott were an outlier; it is highly unlikely that traditional resource planning would result in the Company being insulated from all possible PJM energy market fluctuations.

Q. WAS THERE ANOTHER SOURCE OF PURCHASED POWER AVAILABLE TO THE COMPANY AT A LOWER COST DURING THE ELLIOTT EMERGENCY?

A. No. It was a PJM system emergency; if excess power was available in the market, then scarcity pricing and emergency conditions would not have occurred. Additionally, it is fundamental under economic principles of supply and demand that a willing market seller of energy would not sell available energy during such an event for less than the transparent spot market price of energy.

Q. HYPOTHETICALLY, WHAT WOULD HAVE BEEN THE FINANCIAL RESULT HAD THE COMPANY PURCHASED TERM FINANCIAL POWER DURING 2022 IN AN AMOUNT TO COVER THE COMPANY'S PEAK LOAD DURING THE ELLIOTT EXTREME COLD EVENT?

A. Hypothetically speaking, had the Company known it would need 283 MW[6] of additional purchased power during Elliott, and had it purchased financial power[7] in

[6] Peak Kentucky Power load during Elliott minus generation resource (Mitchell and Big Sandy 1) ICAP.
[7] The reference to financial power is referring to any purchase that is not asset specific.

advance of December 2022, customers' resulting fuel costs would have been significantly higher. This is due to the high natural gas and power prices during 2022, which caused the forward prices of financial power to be very high during 2022. Had the Company transacted for this hypothetical amount of purchased power in any of the five months leading up to December of 2022, purchased power expenses for December would have been higher than what the Company actually experienced in three out of the five months. Based on this information, the only way a hypothetical financial power transaction would have potentially benefitted the Company's customers would have been based on arbitrary market timing. Said another way, if the Company by luck alone had transacted based on October forward prices having perfect knowledge of the unknown Winter Storm Elliott to come, purchased power expense could have been lower than what was realized.

Had the Company bought that same amount of financial purchased power for the balance of the winter (January-March in addition to December), rather than settling its net load requirements at the spot market energy prices, total fuel costs would have been materially higher under every scenario as can be seen in Figure AEV-4. Furthermore, as discussed later in the financial power hedging portion of my testimony, these types of extreme load spikes are not what a hedging program is meant to insulate against. In fact, the Company's proposed hedging program will utilize weather normal load levels (which do not include extreme cold or heat events that materially impact retail load) and would leave one standard deviation of the total position open to the spot energy market.

Figure AEV-4 - Hypothetical Forward Purchased Power Transactions

MW Needed to Cover Elliott Peak	**283**				
July Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$87.96	$113.72	$106.52	$76.42	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$864,103**	**$16,293,909**	**$14,946,855**	**$10,011,819**	**$42,116,685**
August Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$108.04	$136.92	$126.07	$78.07	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$5,085,802**	**$21,171,569**	**$18,659,357**	**$10,358,721**	**$55,275,449**
September Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$94.97	$126.51	$111.50	$75.71	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**$2,337,913**	**$18,982,929**	**$15,892,546**	**$9,862,545**	**$47,075,934**
October Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$73.45	$106.30	$91.27	$67.17	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($2,186,537)**	**$14,733,898**	**$12,050,914**	**$8,067,062**	**$32,665,337**
November Forwards	**December**	**January**	**February**	**March**	**Total**
Forward Price	$80.90	$99.41	$91.97	$67.02	
Liquidated Price	$83.85	$36.22	$27.81	$28.80	
Increase in Purchase Power Exp	**($620,220)**	**$13,285,317**	**$12,183,842**	**$8,035,525**	**$32,884,465**

A similar fact pattern would be true if the Company had purchased a block of financial power to replace Big Sandy Unit 1's 295 MW of generation when it became known that the emergent generator issue with Big Sandy Unit 1[8] would keep the unit in a planned outage for all of December 2022. Had the Company purchased that block of power[9] for the remainder of the month of December after the equipment issue was discovered on December 2, 2022, total purchased power costs realized would not have changed materially. Forward pricing for the balance of December 2022 was

8 As discussed in more detail by Company Witness Kerns, the issue was discovered on December 2, 2022.
9 295 x 696 hours in the balance of the month = 205,320 MWh of hypothetical purchased power transaction.

$82.93/MWh and the average December 2022 liquidated price was $83.85. Therefore, less than a dollar per MWh (or roughly $190,000 in total) of savings was hypothetically possible. It should be noted that making such a transaction at a single point in time, rather than layering in over time as the Company is proposing in its hedging program, can be financially risky. This is very evident when looking out just a single month from December of 2022 to January of 2023, when the average PJM spot market price shown in Figure 4 dropped to just $36.22/MWh.

Q. DID THE COMPANY CURTAIL ITS NON-FIRM OR INTERRUPTIBLE CUSTOMERS DURING ELLIOTT TO REDUCE THE AMOUNT OF PURCHASED POWER IT INCURRED?

A. Yes, the Company called for curtailments of its interruptible customers[10] on December 23, 2022 and December 24, 2022, and those customers reduced their operations to their contracted firm service level during these events.

Q. DID THE COMPANY HAVE TO ENGAGE IN ROLLING BLACKOUTS DURING WINTER STORM ELLIOTT?

A. No. The Company was able to provide reliable service to its customers during the Winter Storm Elliott and had no power supply-related outages.

Q. DOES THE COMPANY MEET ITS CAPACITY OBLIGATIONS AND RESERVE MARGIN REQUIREMENTS IN PJM?

A. Yes it does. The Company plans for and meets its generation capacity obligations in PJM, which is the balancing authority to which the Company belongs. The current

[10] Tariff DRS and special contract.

capacity obligation is determined using a summer 5CP measurement. The Company's customers have benefited from this market design because the Company's winter peak is higher than its summer peak. The Company sources the additional winter energy requirements for its customers from the PJM energy markets, which is an option available to it as a member of the PJM RTO. The matter of securing the excess winter energy requirements from the PJM energy market is a matter of economics, and not reliability, which is why the Company did not have any firm load shedding events during Elliott.

Q. IS THE CURRENT STRATEGY OF MAKING BILATERAL MARKET PURCHASES OF CAPACITY AND UTILIZING THE PJM SPOT ENERGY MARKET FOR EXCESS ENERGY NEEDS IN LINE WITH THE COMPANY'S PREVIOUS IRP?[11]

A. Yes it is. Both the Attorney General and Kentucky Industrial Utility Customers, Inc. ("KIUC") (collectively, "AG-KIUC") advocated for the use of short-term bilateral market capacity purchases and the PJM spot energy market in lieu of the Company owning long-term assets to fill the same need. In their joint comments on Kentucky Power's 2019 IRP Preferred Plan AG-KIUC stated: "This is further evidence that the Company should adjust its Preferred Plan to include additional MPs [market purchases], and it should not be overlooked that we have been in a low-cost

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[11] *In The Matter Of: Electronic 2019 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2019-00443.

environment for more than ten years with no indication this will change any time soon."[12] The joint comments also state:

> In its response to Staff's Post Hearing Request No. 2, the Company noted that when its winter peak demand is greater than its summer peak demand obligation, it buys energy from the pool. When this situation occurs, it does not mean that Kentucky Power suffers from a reliability issue, but instead it means it is more economic for Kentucky Power to purchase energy from within the PJM market than for Kentucky Power to construct new resources, especially since there is sufficient capacity available in PJM to meet Kentucky Power's winter peak. As long as Kentucky Power meets its PJM summer peak demand obligation, and PJM ensures that the entirety of the PJM System is reliable on a year round basis, then it would become an economic matter as to whether Kentucky Power should construct additional capacity to avoid having to purchase during the winter period. Even if the Company were to construct physical assets such as combustion turbine units to satisfy its winter peak, Kentucky Power possibly would still purchase energy from the PJM market during the winter as opposed to running its newly built resources since PJM market resources could be cheaper to operate than Kentucky Power's new resources.[13]

This concept is exactly what the Company has been doing since the end of the Rockport UPA and will continue to do until a long-term replacement solution is proposed by the Company and approved by this Commission.

Q. DID THE COMPANY ACT PRUDENTLY WHEN IT INCURRED THE WINTER STORM ELLIOTT PUE EXPENSE?

A. Yes. The Company took all reasonable efforts available to it to reduce the total amount of purchased power expense during the extreme winter storm Elliott event. This includes operating the Mitchell Plant through the event and curtailing interruptible

[12] Joint Review of Kentucky Power's 2019 Integrated Resource Plan at 9, *In The Matter Of: Electronic 2019 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2019-00443 (February 25, 2021).
[13] *Id.* at 16.

customers during peak periods. The Company's actions in response to Winter Storm Elliott were reasonable and prudent.

The entire PJM region, and much of the United States as the storm made its way from west coast to east coast, was impacted by Elliott. Elliott was not just a Kentucky Power issue, as it financially and operationally impacted many utilities in the region. There was no reasonable and foreseeable way for the Company to avoid the resulting PJM energy market exposure in a way that would have materially changed the realized costs.

Q. PLEASE DESCRIBE WHAT CAUSED THE APPROXIMATELY $3.2 MILLION OF NON-WINTER STORM ELLIOTT TEST YEAR PUE EXPENSE.

A. Purchased power costs are excluded from FAC recovery when they are in excess of the Company's highest cost source of internal generation, including the approved hourly PUE calculation. It is not a cap on the level of costs that are recoverable, but rather on what level of costs can be recovered in the monthly FAC rate updates. These instances where purchased power costs exceed the PUE calculation are generally occurring because the implied heat rate of the PJM energy market is higher than that of the hypothetical combustion turbine used in the PUE calculation, the locational natural gas price of the marginal unit in PJM's hourly economic dispatch solution is higher than that of the price used in the PUE calculation, or some combination thereof. These purchased power costs are still reasonably incurred as they are the product of hourly economic dispatch which is optimized across the PJM RTO pursuant to PJM's FERC approved tariff. They are next cheapest spot source of energy available to serve customers.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR RECOVERY OF THE PUE EXPENSE INCURRED SINCE THE COMPANY'S LAST BASE RATE CASE?

A. As described by Company Witness West, the Company respectfully requests, based upon the evidence supporting the prudency of the Winter Storm Elliott PUE expense presented in this case, that the Commission find those costs were prudently incurred. The Company further requests that the Commission include the Winter Storm Elliott PUE expense in the revenue requirement approved in its final order in this case, up to the noticed total revenue requirement. To be clear, the Company is not requesting recovery of revenue above the amount included in its public notice in this case. The Company proposes to amortize incremental non-Winter Storm Elliott PUE expense incurred since the Company's last base rate case over three years, as detailed by Company Witness Whitney.

V. FINANCIAL POWER HEDGING PROPOSAL

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT ENERGY POSITION GIVEN ITS HISTORIC LOAD CHARACTERISTICS AND CURRENT SUPPLY RESOURCES.

A. The Company has been backstopped from an energy standpoint by a pooling arrangement since 1951. Until December 31, 2013[14] the Company was a member of the AEP Interconnection Agreement ("AEP East Pool"), where any energy shortfall

[14] The AEP East Pool terminated on this date by mutual notice.

was first met by the other Companies in the East Pool. After the AEP East Companies joined the PJM RTO in 2004, any additional energy requirements beyond what could be provided by the East Pool were sourced from the PJM spot energy market. This included economic dispatch of the East Pool generating resources by PJM, so if it were more economic to purchase energy from PJM than to generate energy from the East Pool resources, the Companies did so, and customers benefited from the lower of cost to produce or what could be purchased on the market. Beginning in 2014, the East Pool was no longer a source of energy for the Company and its energy requirements were sourced from the PJM RTO spot energy market with that same economic dispatch concept applying. In December 2022 the Company became shorter from an energy perspective (load requirements are greater than available economic generation resources over some period of time) relative to its load requirements when the Rockport UPA expired. To be clear, purchasing energy from the market to meet its requirements is not something new for the Company, it just now finds itself in a larger energy deficit than it has had previously.

Q. HOW DO THE COMPANY'S GENERATING RESOURCES HEDGE CUSTOMER MARKET RISK?

A. Because the Company sells all of its available generation resources into PJM's spot energy market and purchases all of its load from the same market, the net position if short is what is actually exposed financially to the spot energy market. Thus, the Company's generating resources provide a physical hedge on the spot energy market. During times of planned or forced outages, absent taking on additional resource hedge positions, the physical hedge position provided by the Mitchell and Big Sandy plants will decline, leaving Customers more exposed to PJM's spot energy market price volatility. However, the Company can reduce this exposure by purchasing financial hedges to replace the generation.

Q. DEFINE THE COMPANY'S OPEN ENERGY POSITION SUBJECT TO PJM SPOT ENERGY MARKET VOLATILITY.

A. The Company's Open Energy Position exposed to PJM spot energy market volatility is defined as its hourly retail load less the generation from Mitchell and Big Sandy generation plants.

Q. CAN THE COMPANY REDUCE THE IMPACT THAT PJM'S SPOT ENERGY MARKET HAS ON ITS OPEN ENERGY POSITION?

A. Yes. Although no entity can accurately predict future energy prices, a structured program that layers in financial hedges over time will help smooth out the impact of PJM's spot energy market price volatility on the Company's Open Energy Position resulting in greater fuel cost certainty for customers.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED FINANCIAL HEDGING PLAN.

A. The Company proposes to use financial hedge products to mitigate the volatility of its PJM spot energy market energy purchases for its Open Energy Positions. PJM AD HUB fixed-for-floating price swaps, also known as contracts for differences, will be used to reduce customer exposure to the volatility in market prices. These forward contracts will be purchased in layers over time to match the Company's target hedge position and smooth out the impact of price volatility in the market. The hedging plan would provide the flexibility to modify or unwind executed forward contracts, as necessary, when adjustments or changes are made to the forecasted load or planned outage schedules at the Mitchell and Big Sandy generation plants. If the PJM AD HUB forward future market is not liquid enough to purchase the target hedge position, the Company may purchase financial future contracts from adjacent zones or other liquid trading hubs, such as the PJM West Hub, to fill in the short position.

Q. WHAT IS THE PROPOSED TIME HORIZON FOR THE FINANCIAL HEDGING PLAN?

A. The Company proposes a financial hedge time horizon of a rolling 36-month period so it can layer purchases of forward contract positions in equal one-third tranches, with the first purchase at 36 months, the second at 18 months, and the third at 6 months, in advance of the respective hedge period.

Q. WHAT IS THE PROPOSED START DATE OF THE FINANCIAL HEDGING PLAN?

A. Upon Commission approval of the financial hedging plan.

Q. HOW WILL THE COMPANY DETERMINE THE APPROPRIATE MWH TO HEDGE IN A GIVEN PERIOD?

A. For each hedge interval, the Company will calculate its Interval Hedge Percent by taking the forecasted generation from the Mitchell and Big Sandy plants based on the fuel purchased in MWh plus any purchased forward hedge contracts (intervals 2 and 3) divided by the forecasted weather normalized retail load in MWh less one standard deviation of its forecasted weather normalized retail load in MWh. Since forecasts are never perfect, a portion of the Open Energy Position will be left exposed to the PJM spot energy market, one standard deviation represents that amount.

$$\text{Interval Hedge Percent (\%)} = \frac{\text{Forecasted Big Sandy and Mitchell Generation (MWh)} + \text{Purchased Forward Hedge Contracts (MWh)}}{\text{Forecasted Load (MWh)} - 1\sigma\ \text{Forecasted Load (MWh)}}$$

The Target Hedge Percent in Figure AEV-5 below represents the targeted amount of the Company's Open Energy Position to be hedged for a given hedge interval. When the Interval Hedge Percent is less than the Target Hedge Percent, the Company will calculate the Target Hedge Position for that interval and purchase forward energy contracts to hedge its Open Energy Position up to the Target Hedge Percent.

Figure AEV-5

Hedge Interval	Target Hedge Percent
Interval 1 (36-months prior to flow)	33%
Interval 2 (18 months prior to flow)	67%
Interval 3 (6-months prior to flow)	100%

The Target Hedge Position in MW is calculated by taking the generation in MWh from Mitchell and Big Sandy plus any purchased forward hedge contracts (intervals 2 and 3) less the Company's forecasted weather normalized retail load in MWh as reduced by one standard deviation of its forecasted weather normalized retail load in MWh times the Target Hedge Percent, divided by the number of hours in the period.

$$\text{Target Hedge Position (MW)} = \frac{\begin{array}{c}\text{Forecasted Big Sandy and Mitchell Generation (MWh)} + \\ \text{Purchased Forward Hedge Contracts (MWh)} - [(\text{Forecasted Load (MWh)} - 1\sigma\ \text{Forecasted Load (MWh)})] \times \text{Target Hedge Percent (\%)}\end{array}}{\text{Number of Hours in Hedge Period (Hrs)}}$$

In the event that the forward future market is not liquid enough to purchase the number of MWh of financial energy needed to reach the Target Hedge Percent for a given hedge interval, hedges will be purchased off-cycle to fill in the short positions.

Q. WILL THE COMPANY PURCHASE FUTURE ENERGY CONTRACTS TO HEDGE ITS OPEN ENERGY POSITION IN ALL THREE HEDGE INTERVALS?

A. The Big Sandy and Mitchell plants should provide enough generation to cover the Target Hedge Percent during the first two intervals in most scenarios. During the third interval, six months prior to the hedge period, future energy contracts may be needed to reach the Target Hedge Percent. This may change over time as operating and outage schedules change.

Q. UNDER THE PROPOSED FINANCIAL HEDGING PLAN, HOW MANY MWH OF THE COMPANY'S OPEN ENERGY POSITION WOULD BE HEDGED IN 2024?

A. Based on the current weather normalize load forecast and outage schedules for the Michell and Big Sandy Plants, the Company would purchase approximately 600,000 MWh of forward energy contracts to cover the Target Hedge Position in 2024. Once purchased, the Company's current forecasted load less one standard deviation would be hedged at 67%. The forward energy contract purchase timeline would be condensed given the limited number of months between the proposed program start date and the hedge period.

Q. PLEASE PROVIDE A HISTORICAL EXAMPLE OF THE PROPOSED FINANCIAL HEDGING PLAN AND ITS IMPACT ON CUSTOMER FUEL COSTS?

A. **Figure AEV-6**

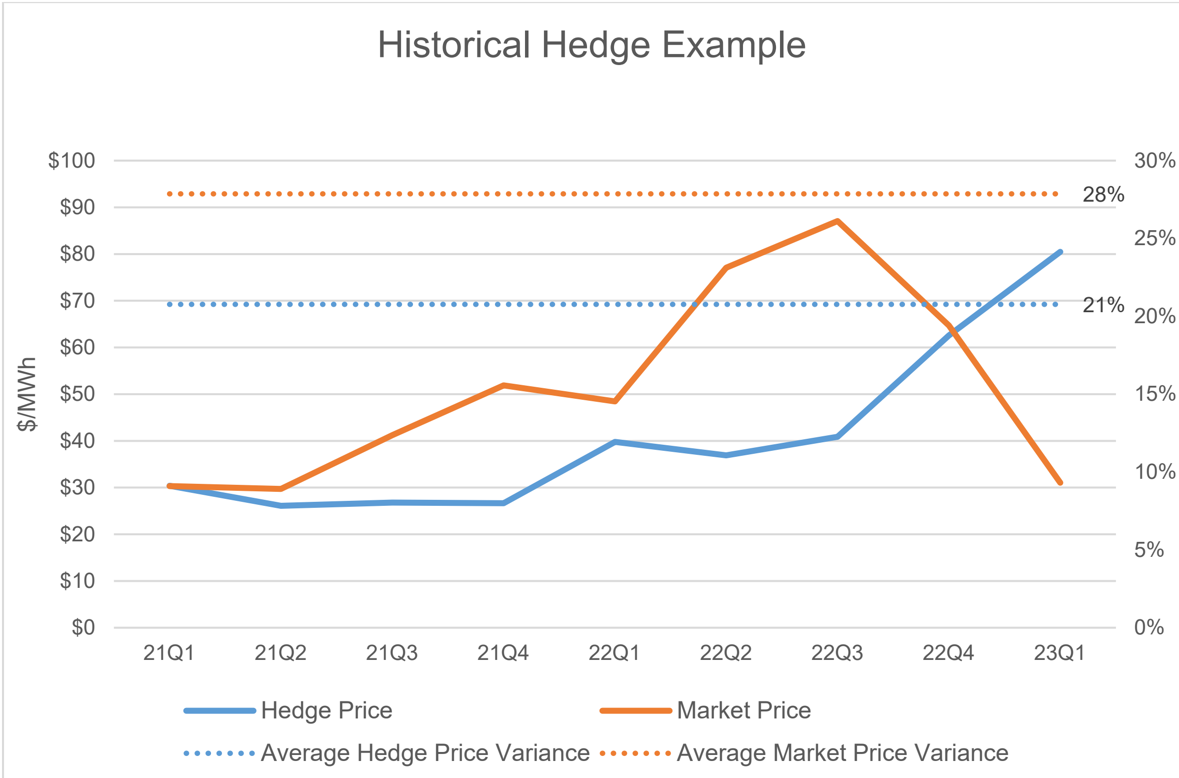
Historical Example Hedge Transactions

Hedge Interval 3									
Purchase Date	**21Q1**	**21Q2**	**21Q3**	**21Q4**	**22Q1**	**22Q2**	**22Q3**	**22Q4**	**23Q1**
7/1/2020	$ 30.38								
10/1/2020		$ 26.10							
1/2/2021			$ 26.79						
4/1/2021				$ 26.66					
7/1/2021					$ 39.79				
10/1/2021						$ 36.91			
1/2/2022							$ 40.87		
4/1/2022								$ 62.58	
7/1/2022									$ 80.47
Day-Ahead Settle Price	$ 30.33	$ 29.71	$ 41.22	$ 51.88	$ 48.46	$ 77.06	$ 87.06	$ 64.70	$ 31.05
Credit/(Charge)	**$ (0.05)**	**$ 3.61**	**$ 14.43**	**$ 25.22**	**$ 8.67**	**$ 40.15**	**$ 46.19**	**$ 2.12**	**$ (49.42)**

It is estimated that for all nine hedging periods, the Company would have had sufficient generation from the Big Sandy and Mitchell plants to cover the Target Hedge Percent during the first two hedge intervals; therefore, all hedge transactions would have been purchased for the third hedge interval. For the hedging period beginning in January and ending in March of 2021 (21Q1), the forward energy contract pricing during the third hedging period was $30.38/MWh and the average PJM spot energy market price of energy for the hedge period was $30.33MWh. In this example the average hedge contract price was greater than the PJM spot energy market price creating a hedging loss of $0.05/MWh for customers. The $0.05/MWh hedging loss would have been charged to the FAC, thereby increasing customer's fuel costs. Similarly, For the hedging period beginning in April and ending in June of 2021 (21Q2), the forward energy contract pricing during the third hedging period was $26.10/MWh and the average PJM spot energy market price of energy for the hedge period was $29.71/MWh. In this example the average hedge contract price was less than the PJM spot energy market price creating a hedging gain of $3.61/MWh for customers. The $3.61/MWh hedging gain would have been credited to the FAC, thereby reducing customer's fuel costs.

The goal of the proposed hedging plan is not to reduce customer's fuel costs over time; rather, it is to reduce their exposure to the volatility of the PJM spot energy market, especially when the Company's generating facilities have scheduled outages, leaving customers more exposed to PJM's Day-ahead market. The proposed hedging plan will reduce customer's sensitivity to PJM's spot market price volatility by creating more predictable fuel costs over time. The graphs in Figure AEV-7 below illustrate how hedging can help smooth out customer fuel costs. Had the Company incorporated a structured hedging program between January 2021 and March 2023, Customers would have been exposed to an average 21% price variance between their monthly fuel charges rather than the 28% variance seen in the spot market.

Figure AEV-7


Historical Hedge Example
$/MWh
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
30%
28%
25%
21%
20%
15%
10%
5%
0%
21Q1
21Q2
21Q3
21Q4
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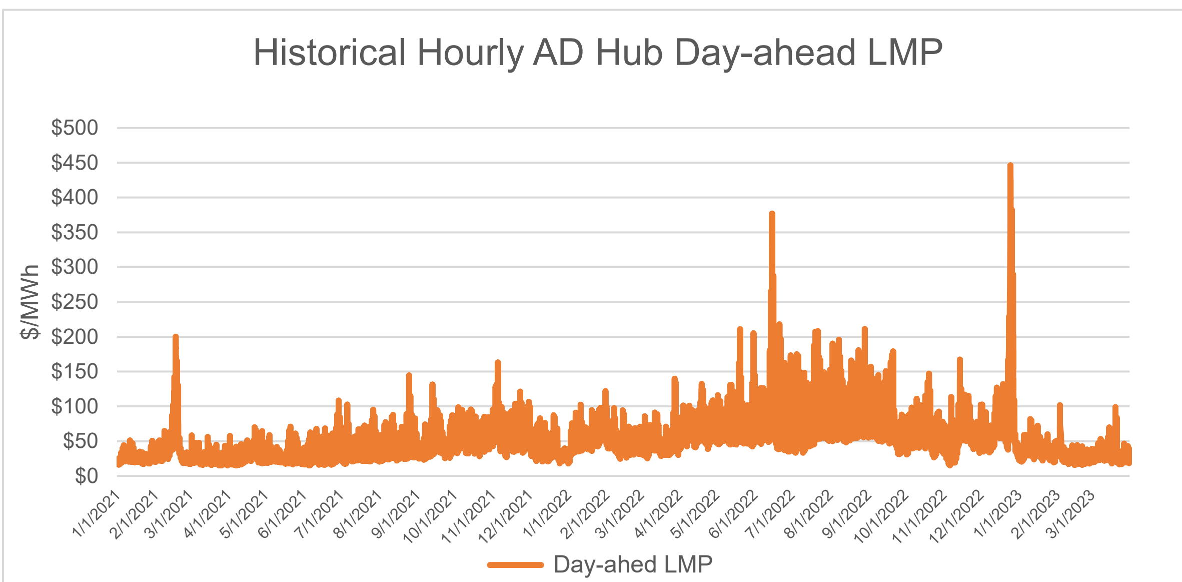
22Q2
22Q3
22Q4
23Q1
Hedge Price
Market Price
Average Hedge Price Variance
Average Market Price Variance


Historical Hourly AD Hub Day-ahead LMP
$/MWh
$500
$450
$400
$350
$300
$250
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Day-ahed LMP

Q. WHAT RATE RECOVERY TREATMENT IS THE COMPANY SEEKING REGARDING ITS PROPOSED FINANCIAL POWER HEDGING PROGRAM?

A. The Company proposes that all Commission-approved financial power hedging program-related contract settlements (gains and losses) and related contract costs be recovered through the FAC. A gain will be realized when the contracted price of financial power is less than the realized LMP value at the time of settlement. A loss will be realized when the opposite is true. The Company proposes that the financial power hedging program transactions will not be subject to the PUE FAC limitation as they are forward financial contracts entered into to reduce fuel rate volatility and market exposure, not to necessarily produce the absolute lowest purchased power cost in any hour.

Q. WILL THE COMPANY MAKE ANY FINANCIAL GAINS FROM THE PROPOSED FINANCIAL HEDGING PROGRAM?

A. No. The Company's proposed financial hedging program is designed to smooth out the impact of PJM's spot energy market price volatility on the Company's Open Energy Position and provide greater fuel cost certainty for customers. The hedging plan effectively locks-in or caps the price of future energy purchases for customers. If the actual energy price in the future turns out to be lower than the hedged price, customers will end up paying more for energy than they would have if the Company had purchased its Open Energy Position from the PJM spot energy market. This incremental cost will flow through the FAC as a hedge charge. Conversely, when the actual energy price turns out to be greater than the hedge price, customers will pay less than they would have if the Company had purchased its Open Energy Position from the PJM spot energy market. Any credits or charges (gains and losses) associated with the hedging program will be passed back to customers through the FAC. The potential for realized hedge charges from this program is essentially the cost of reducing volatility in customers' monthly fuel rates.

Q. HOW WOULD THE FINANCIAL POWER HEDGING PROGRAM BE ACCOUNTED FOR?

A. The financial power product being employed is expected to be a derivative, which would be subject to mark to market ("MTM") treatment. Should the Commission authorize the Company to pass back any credits or charges (gains and losses) associated with the hedging program to customer through the FAC, the Company would defer MTM gains or losses prior to hedge liquidation to a regulatory asset or liability which would unwind when the financial power contracts are liquidated at the time of settlement. The net gain or loss from liquidation would flow through the FAC as discussed earlier.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE COMPANY'S PROPOSAL.

A. PJM's energy market is susceptible to market volatility largely driven by the underlaying and interrelated fuel markets, operating conditions, and has been exacerbated over the years by extreme weather disturbances. A significant portion of the Company's load is subject to the day-to-day volatility of PJM's spot market and becomes even more magnified during times of planned outages at the Mitchell and Big Sandy plants. To help mitigate the exposure to the daily market volatility, the Company is proposing a rolling 36-month financial hedging plan to provide customers with greater fuel cost certainty over time. Although the monthly results of the Company's proposed hedging plan may not result in net fuel cost savings for customers, it will reduce their exposure to the fluctuations in the PJM Day-ahead energy market by creating more predictable fuel costs over time. This will leave customers better positioned to budget for and manage their monthly energy bills.

VI. DISTRIBUTED SOLAR PROPOSAL (SOLAR GARDEN PROGRAM)

i. Proposed Ownership and Accounting Structure

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED SOLAR GARDEN PROGRAM AND THE PROGRAM'S GENERAL COST RECOVERY STRUCTURE.

A. The Company proposes to own and operate one or more solar facilities, not to exceed 10 MW in individual size, to be located on the Company's distribution system. The aggregate capacity of all the solar sites will not exceed 25 MW. This program will help establish solar generation within the Company's service territory and fill a capacity need that starts in 2026. Projects will be considered a prudent investment if the Net Present Value[15] ("NPV") of the benefits and costs of the project do not exceed the NPV of the equivalent avoided capacity costs, an example of the items considered in the analysis is shown in Figure AEV-8 below, and Figure AEV-9 is an illustrative example of the economic test. The Company is seeking approval of this program so it can solicit through requests for proposals and acquire the projects without further Commission approvals if a project meets the proposed requirements.

[15] The discount rate would be equal to the Company's approved after tax weighted average cost of capital.

Figure AEV-8

Inputs of NPV Economic Prudency Test

Cost of Service Build Up	Years 1-35
O&M	(x)
Property Taxes	(x)
Insurance	(x)
Land Lease	(x)
ARO Depreciation	(x)
Accretion Expense	(x)
Depreciation Expense	(x)
Income and Property Taxes	(x)
PTC Revenue	(x)
Return on Rate Base	(x)
Total Cost of Service	(xx)

Test Input	Value	
NPV of Cost of Service	(xx)	**a**
NPV of Energy Value	MWh x Energy Price	**b**
NPV of Ancillary Charges	MWh x Ancillary Charge	**c**
NPV of OATT	Average 12 CP reduction x Annual Transmission Revenue Requirement $/MW-yr	**d**
NPV of REC Value	MWh x REC Price	**e**
Total NPV		**f = a -b-c-d-e**
NPV of Capacity	Avoided Capacity x Capacity Price	**g**
Is (f) greater than (g)?	**Prudency Test**	

Figure AEV-9

Prudent Investment Example

NPV of Cost of Service	(64,904,189)	(63,595,882)
NPV of Benefits (Energy, OATT, Ancilary Service, REC Values)	49,500,986	70,342,556
Total NPV (a)	(15,403,203)	6,746,673
NPV of Capacity Cost (b)	(13,387,086)	(17,219,757)
Is a greater than b?	FALSE	TRUE

The Company is proposing to recover the net costs of these solar facilities acquired through the solar gardens program through Tariff PPA until they can be included in the Company's rate base. The energy benefits from the solar facilities will manifest as a reduction in FAC costs. The benefits and costs associated with these solar facilities are discussed later in my testimony.

Q. IS THIS PROPOSAL IN LINE WITH THE COMPANY'S RECENTLY FILED 2022 IRP?

A. Yes. The Company's going in capacity positions shows a 115MW shortfall in 2026, which grows even larger through 2037. The Preferred Plan shows 250MW of new solar being added in 2027 and further solar additions in 2028 and 2029.

Q. HOW WILL THE SOLAR GARDEN FACILITIES INTERACT WITH PJM?

A. The solar facilities will be connected to the Company's distribution system. They will act as a load reducer for PJM settlement purposes. This means that the Company's internal distribution load will be reduced by the output of the solar facilities, which will provide the Company and its customers with various PJM benefits. The solar facilities will not be market-facing generation resources and will not participate in PJM's energy, ancillary service, or capacity markets.

Q. WHAT OPERATIONS AND MAINTENANCE COSTS ARE ASSOCIATED WITH THE SOLAR FACILITIES?

A. Outside of general operating and maintenance costs, there are property taxes, insurance expenses and if the Company has to lease the land that the facilities reside on, land lease payments to the lessors of the land.

Q. WHAT IS THE DEPRECIABLE LIFE OF THE PROPOSED SOLAR FACILITIES?

A. The depreciable life of the proposed solar facilities is 35 years. This life is based upon the Company's current accounting policies related to solar generation technology. The

35 year life would also be supported by incremental capital additions over the life of the plant to lengthen the life of inverters.

Q. ARE THERE ANY ASSET RETIREMENT OBLIGATIONS ("AROs") ASSOCIATED WITH THE COMPANY'S PROPOSED SOLAR FACILITY?

A. Yes, if the Company leases the land, then at the end of the solar facilities' useful life, and the corresponding end of the land lease, the Company has the legal obligation to remove the solar generating equipment from the lessors' land. As such, the Company will recognize ARO depreciation expense in an amount equal to the estimated demolition cost 35 years after the solar facilities begin commercial operation and an estimate of the salvage value associated with the racking equipment and other salvageable items.

Q. DOES THE FEDERAL PRODUCTION TAX CREDIT APPLY TO THE PROPOSED SOLAR GARDENS?

A. Yes, it is expected that the solar gardens will qualify and generate the Production Tax Credit ("PTC"), at 100%. The Inflation Reduction Act ("IRA") was signed into law by President Biden on August 16, 2022, which created a new technology-neutral Clean Electricity PTC. The realized value of PTCs generated will be passed back to customers as a reduction to the cost of service of the facilities. Depending on where the facilities are ultimately sited, there is a possibility that they could qualify for a 110% PTC based on the "Energy Communities" portion of the IRA.

Prior to the passage of the IRA, the facilities would have only qualified for the Solar Investment Tax Credit ("ITC"). Every solar facility within this program, will be individually evaluated to ensure max benefits are being recognized for customers.

ii. Customer Benefit Analysis

Q. WHAT FINANCIAL BENEFITS WILL ALL OF THE COMPANY'S CUSTOMERS RECEIVE FROM THE SOLAR GARDEN PROGRAM?

A. As mentioned earlier, the solar facilities will reduce the Company's wholesale load that it purchases from PJM each hour that the solar facilities are producing solar power and injecting it into the Company's distribution system. Because of this, the Company will realize energy, ancillary service, and capacity benefits related to both its generation and transmission obligations in PJM.

Energy Benefits

The energy benefits will manifest by the Company purchasing approximately 33,500 fewer MWh of on-peak energy (49,008 MWh of energy in total) from the PJM RTO annually. This is because the Company purchases all of its load requirements from the hourly energy markets of PJM and sells its generation resources into those same markets. The monthly cost reconstruction/economic dispatch and deferred fuel accounting process ensures that customers receive the lowest cost resources and the resulting monthly average costs through a combination of the Company's base fuel rates and the fuel adjustment clause. The proposed solar facilities will reduce the Company's on-peak load[16] that it purchases from PJM, thus avoiding on-peak purchases and the higher hourly pricing associated with them.

[16] While solar produces energy during "on-peak" daytime hours, weekend days are considered off-peak for pricing purposes.

Ancillary Service Benefits

Also due to the reduction of the Company's PJM load, customers will receive a benefit by avoiding hourly PJM ancillary service load charges.

Capacity Benefits

To the extent that the solar facilities are producing energy during the Company's capacity cost-causing hours in PJM, Kentucky Power will have a lower generation capacity obligation, which will result in lower generation capacity costs.

LSE OATT Charges

Similar to the generation capacity peak reduction, the facilities will also reduce the Company's 12CP used to allocate PJM load serving entity Open Access Transmission Tariff charges to the Company.

The solar facilities also produce one renewable energy certificate ("REC") per MWh of energy generated. These RECs can then be sold bilaterally into the marketplace to offset the cost of the solar facilities.

Q. ARE THERE ADDITIONAL NON-COST OF SERVICE BENEFITS RELATED TO THE COMPANY'S PROPOSED SOLAR FACILITIES?

A. Yes. The solar facilities will pay property taxes to the Commonwealth and the localities where they are built. There will also be local jobs created during the construction and operation of the facilities, all within the Company's service territory.

Q. ARE YOU PROPOSING THAT ANY OF THE NON-COST OF SERVICE BENEFITS BE PRICED INTO THE PROPOSED SOLAR GARDEN PROGRAM?

A. No. The Company's rates are based on cost of service ratemaking. They do not consider non-cost of service economic factors or other externalities. Although these things may exist and may provide positive economic and societal benefits, they do not belong in the Company's rates.

iii. Low-Income Benefit Option

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED LOW-INCOME BENEFIT OPTION IN RELATION TO THE SOLAR GARDEN PROGRAM.

A. The Company has approximately 11,500 customers that are participating in government assistance programs, such as the Federal Low Income Home Energy Assistance Program ("LIHEAP"). The Company is proposing to provide 50 percent of the energy benefits from the Solar Gardens to these customers through a yearly bill credit, to be credited in their January billing when customer bills are generally higher due to heating usage. The customers will not have to sign up for the option, they will be automatically enrolled.

Q. HOW WILL THE ENERGY CREDIT BE CALCULATED?

A. The Company is proposing to use the hourly MWh produced from the solar facilities for the previous 12 months and multiply that by the Day Ahead Local Marginal Price ("DA LMP") for the corresponding hour. The total will then be multiplied by 50 percent and divided by the number of customers identified as low-income through their participation in LIHEAP as of December 31. Based on high-level estimates, this credit could amount to approximately $66 per customer annually.

Q. IS THE 50 PERCENT ENERGY BENEFIT THE ONLY BENEFIT THESE CUSTOMERS WILL RECEIVE FROM THE SOLAR GARDEN PROGRAM?

A. No. These customers will also still receive all of the other the benefits mentioned in the customer benefit analysis portion of my testimony.

<u>iii. Summary</u>

Q. PLEASE SUMMARIZE THE ACCOUNTING FOR THE PROPOSED SOLAR GARDEN FACILITIES AND THE LOW INCOME OPTION.

A. The Company is proposing to flow all non-energy benefits and all costs through Tariff PPA and will be subject to the normal true-up process for Tariff PPA. Energy benefits will flow through the FAC in the form of reduced load requirements being purchased from the PJM spot energy market. The Company is also proposing to provide 50 percent of the energy benefits from the Solar Gardens to low-income customers through a yearly bill credit, as discussed above. The 50 percent of the energy benefit being credited to low-income customers would also be recovered through Tariff PPA.

Q. SHOULD THE PROPOSED SOLAR GARDEN PROGRAM BE APPROVED?

A. Yes, because of the benefits to customers, the proposed built in customer protections, and the need for solar identified in the Company's 2022 IRP, the proposed solar garden program should be approved.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is Managing Director, Renewables Fuel Strategy that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Alex E. Vaughan

State of Ohio)
) Case No. 2023-00159
County of Franklin)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on 6/27/23.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires Never

Notary ID Number None

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2023-00159
Regulatory Assets and Liabilities; (4) A	)	
Securitization Financing Order; And (5) All Other;	)	
Required Approvals And Relief	)	

DIRECT TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

LIST OF EXHIBITS

Exhibit	Description
AMM-1	Qualifications of Adrien M. McKenzie
AMM-2	ROE Analyses – Summary of Results
AMM-3	Regulatory Mechanisms
AMM-4	Capital Structure
AMM-5	DCF Model – Utility Group
AMM-6	br + sv Growth Rate – Utility Group
AMM-7	CAPM
AMM-8	Empirical CAPM
AMM-9	Risk Premium Method
AMM-10	Expected Earnings Approach
AMM-11	Flotation Cost Study
AMM-12	DCF Model – Non-Utility Group

DIRECT TESTIMONY OF
ADRIEN M. MCKENZIE, CFA ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q1. Please state your name and business address.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. In what capacity are you employed?

A2. I am President of Financial Concepts and Applications, Inc. ("FINCAP"), a firm providing financial, economic, and policy consulting services to business and government.

Q3. Please describe your educational background and qualifications.

A3. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit AMM-1.

A. <u>Overview</u>

Q4. What is the purpose of your testimony in this case?

A4. As discussed in the testimony of Company Witness Wiseman, Kentucky Power Company ("Kentucky Power" or the "Company") is requesting that the Kentucky Public Service Commission ("Commission") authorize a return on equity ("ROE") of 9.9% for the Company. The purpose of my testimony is to evaluate the reasonableness of the 9.9% ROE requested by the Company, based on my independent assessment of the fair ROE for the jurisdictional electric utility operations of Kentucky Power. In addition, I also examine the reasonableness of Kentucky Power's common equity ratio, considering both the specific risks faced by the Company and other industry guidelines.

Q5. Are you sponsoring any exhibits?

A5. Yes. I am sponsoring the following exhibits:

- Exhibit AMM-1 Qualifications of Adrien M. McKenzie
- Exhibit AMM-2 ROE Analyses – Summary of Results
- Exhibit AMM-3 Regulatory Mechanisms
- Exhibit AMM-4 Capital Structure
- Exhibit AMM-5 DCF Model – Utility Group
- Exhibit AMM-6 br+sv Growth Rate
- Exhibit AMM-7 CAPM
- Exhibit AMM-8 Empirical CAPM
- Exhibit AMM-9 Electric Utility Risk Premium
- Exhibit AMM-10 Expected Earnings Approach
- Exhibit AMM-11 Flotation Cost Study
- Exhibit AMM-12 DCF Model – Non-Utility Group

Q6. Please summarize the information and materials you rely on to support the opinions and conclusions contained in your testimony.

A6. To prepare my testimony, I use information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the organization, finances, and operations of Kentucky Power from my participation in prior proceedings before the Commission. In connection with this filing, I consider and rely upon corporate disclosures, publicly available financial reports and filings, and other published information relating to Kentucky Power. I also review information relating generally to capital market conditions and specifically to investor perceptions, requirements and expectations for utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for Kentucky Power, and they form the basis of my analyses and conclusions.

Q7. How is your testimony organized?

A7. First, I summarize the results of my analyses and present my evaluation of the reasonableness of the 9.9% ROE requested by Kentucky Power, giving special attention to the importance of financial strength and the implications of regulatory mechanisms and other risk factors. My ROE evaluation considers the implications of current capital market conditions, the specific risks for the Company's jurisdictional utility operations in Kentucky, and the Company's requirements for financial strength. My analysis also accounts for flotation costs, which are properly considered in setting a fair and reasonable ROE. In addition, I address the reasonableness of the Company's proposed capital structure.

Next, I briefly review Kentucky Power's operations and finances. I discuss current conditions in the capital markets and their implications in evaluating a just and reasonable return for the Company. I then address the development of the proxy group of electric utilities used to apply my quantitative analyses and compare the risks of this proxy group to the Company. With this as a background, I discuss well-accepted quantitative analyses to estimate the current cost of equity for the proxy group of electric utilities. These include the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical CAPM ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for electric utilities, which are all methods that are commonly relied on in regulatory proceedings. In addition, I discuss the issue of stock flotation expenses and the implications of these legitimate costs on the estimation of a reasonable ROE for the Company.

Based on the results of my analyses, I evaluate the reasonableness of the 9.9% ROE requested by Kentucky Power. My evaluation takes into account the specific risks for the Company's electric operations in Kentucky and Kentucky Power's requirements for financial strength. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, I corroborate my utility quantitative analyses by applying the DCF model to a group of low-risk, non-utility firms.

B. Summary and Conclusions

Q8. What is your conclusion regarding the 9.9% ROE requested by Kentucky Power?

A8. Considering the results of my analyses, along with current capital market conditions, Kentucky Power's specific risk exposures, and the imperative of bolstering the Company's financial strength, my testimony demonstrates that an ROE of 10.6% is warranted. Accordingly, I conclude that Kentucky Power's requested ROE of 9.9% significantly understates investors' required return for the Company. Kentucky Power's requested ROE represents a reasonable compromise between balancing the impact on customers and the need to provide the Company with a return that is adequate to compensate investors.

Also of note, because Kentucky Power's requested ROE of 9.9% already understates investor's required return for the Company, it should not be further reduced for purposes of single-issue cost recovery mechanisms, such as the Environmental Surcharge or Decommissioning Rider, as the Commission did in its January 13, 2021 Order in Case No. 2020-00174. Such a reduction is not justified from a capital attraction point of view because it does not reflect investors' required return for the Company; but in any case, even if the Commission were inclined to make such a reduction, the requested 9.9% ROE is already 70 basis points below the ROE of 10.6% that my testimony supports.

I. RETURN ON EQUITY FOR KENTUCKY POWER

Q9. What is the purpose of this section?

A9. This section presents my conclusions regarding the fair ROE applicable to Kentucky Power's jurisdictional electric utility operations. I also describe the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. Finally, I discuss the reasonableness of the Company's capital structure request in this case.

A. Importance of Financial Strength

Q10. What is the role of the ROE in setting a utility's rates?

A10. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a just and reasonable ROE is integral in meeting sound regulatory economics and the standards established by the U.S. Supreme Court. The *Bluefield* case set the standard against which just and reasonable rates are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.[1]

The *Hope* case expanded on the guidelines for a reasonable ROE, reemphasizing the Court's findings in *Bluefield* and establishing that the rate-setting process must produce an end-result that allows the utility a reasonable opportunity to cover its capital costs. The Court stated:

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital.[2]

In summary, the Supreme Court's findings in *Hope* and *Bluefield* established that a just and reasonable ROE must be sufficient to 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but the Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates (or in determining the allowed ROE),[3] these and subsequent cases enshrined the importance of an end result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected returns available from comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (*e.g.*, DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

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[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

[3] *Id.* at 602 (finding, "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." and, "[I]t is not theory but the impact of the rate order which counts.")

Q11. Throughout your testimony you refer repeatedly to the concepts of "financial strength," "financial integrity" and "financial flexibility." Would you briefly describe what you mean by these terms?

A11. These terms are generally synonymous and refer to the utility's ability to attract and retain the capital that is necessary to provide service at reasonable cost, consistent with the Supreme Court standards. Kentucky Power's plans call for a continuation of capital investments to preserve and enhance service reliability for its customers. The Company must generate adequate cash flow from operations, together with access to capital from external sources, to fund these requirements and for repayment of maturing debt.

Rating agencies and potential debt investors tend to place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors. Investors understand the important role that a supportive regulatory environment plays in establishing a sound financial profile that will permit the utility access to debt and equity capital markets on reasonable terms in both favorable financial markets and during times of potential disruption and crisis.

Q12. What part does regulation play in ensuring that Kentucky Power has access to capital under reasonable terms and on a sustainable basis?

A12. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's Investors Service ("Moody's") noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[4] Similarly,

[4] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014).

S&P Global Ratings ("S&P") observed that, "Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[5] The Value Line Investment Survey ("Value Line") summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[6]

In addition, the ROE set by regulators impacts investor confidence in not only the jurisdictional utility, but also in the ultimate parent company that is the entity that actually issues common stock.

Q13. Do customers benefit by enhancing the utility's financial flexibility?

A13. Yes. Providing an ROE sufficient to maintain the Company's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. <u>Conclusions and Recommendations</u>

Q14. What are your findings regarding the fair ROE for Kentucky Power?

A14. Considering the economic requirements necessary to support continuous access to capital under reasonable terms and the results of my analysis, I conclude that 10.6% represents a fair ROE for Kentucky Power's electric utility operations. The bases for my conclusion are summarized below:

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[5] S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

[6] Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at p. 1780.

- In order to reflect the risks and prospects associated with Kentucky Power's electric utility operations, my analyses focus on a proxy group of eighteen other electric utilities.
- Because investors' required ROE is unobservable and no single method should be viewed in isolation, I apply the DCF, CAPM, ECAPM, and risk premium methods to estimate a just and reasonable ROE for Kentucky Power, as well as referencing the expected earnings approach.
- As summarized on Exhibit AMM-2, considering the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for a regulated electric utility is in the 10.0% to 11.0% range, or 10.1% to 11.1% after accounting for flotation costs.
- My ROE recommendation for Kentucky Power's electric operations is the midpoint of this range, or 10.6%.

Q15. What did the DCF results for your select group of non-utility firms indicate with respect to your evaluation?

A15. As shown on page 3 of Exhibit AMM-12, average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 10.4% to 10.9%. While I did not base my recommendations on these results, they confirm that an ROE of 10.6% falls in a reasonable range.

Q16. What is your conclusion regarding the reasonableness of the 9.9% ROE requested by the Company?

A16. The 9.9% ROE requested by Kentucky Power is significantly less than the 10.6% midpoint of my recommended range. As a result, I believe it understates the current cost of equity to the Company. The 9.9% request falls slightly below the bottom of my cost of equity range, but it nevertheless represents a meaningful increase from the 9.3% authorized in the Company's last rate proceeding, which would improve Kentucky Power's cash flows and financial strength while moderating the impact on customers. The reasonableness of the Company's requested 9.9% ROE is also reinforced by:

- The need to consider ongoing challenges to the Company's credit standing.
- Kentucky Power's chronic inability to earn its authorized rate of return due to ongoing exposure to attrition.

- The additional risks associated with the Company's relatively high concentration of industrial customers and financial leverage.
- The imperative of ensuring that Kentucky Power has the capability to maintain and build its credit standing while confronting potential challenges associated with funding infrastructure development necessary to meet the needs of its customers.

These findings further indicate that a 9.9% ROE for Kentucky Power is reasonable and should be approved.

Q17. What is your conclusion as to the reasonableness of the company's capital structure?

A17. Based on my evaluation, I conclude that the Company's proposed common equity ratio of 41.62% represents a reasonable basis from which to calculate Kentucky Power's overall rate of return. This conclusion was based on the following findings:

- Kentucky Power's common equity ratio is well within the range of capitalizations maintained by the firms in the proxy group of utilities and by other electric utility operating companies based on data at year-end 2022 and near-term expectations.
- While the Company's proposed equity ratio is within the range of comparable company capitalizations, it is below the average equity ratios maintained by these companies.
- Kentucky Power's requested capitalization is consistent with the Company's need to maintain its credit standing and financial flexibility as it seeks to raise additional capital to fund significant system investments and meet the requirements of its of customers.

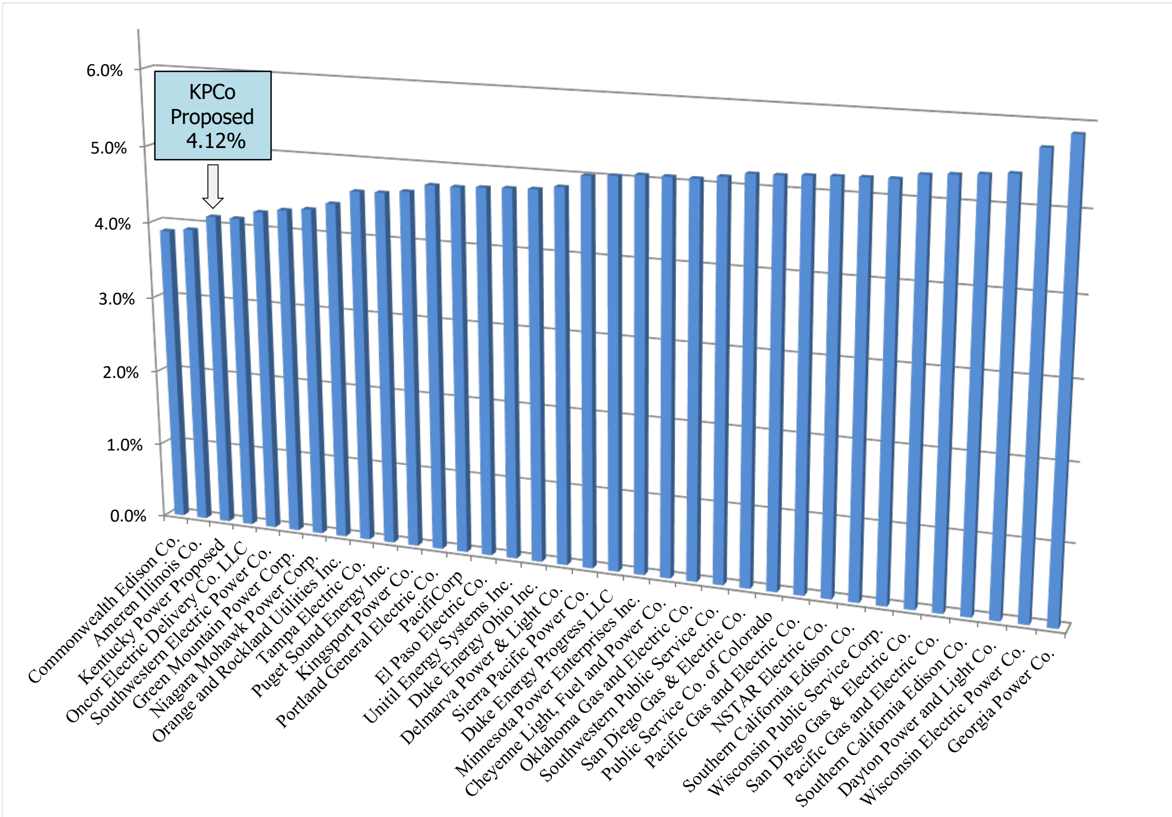
As noted above, Kentucky Power's capital structure contains relatively less common equity than the firms in my proxy group, which reduces the equity return component of the revenue requirements, and in turn, the overall rate of return.

Q18. How does Kentucky Power's requested 4.12% weighted cost of equity compare with those recently approved for electric utilities in other jurisdictions?

A18. The bar chart below shows the weighted costs of equity approved by state regulators for investor-owned electric utilities across the country during 2022 and for the first quarter of 2023. These observations represent all decisions reported by S&P Global Market

Intelligence that specify an ROE and an equity ratio for electric utilities during this period:

FIGURE 1
WEIGHTED COST OF EQUITY – ELECTRIC UTILITIES



Source: S&P Global Market Intelligence, Regulatory Research Associates, *Major energy rate case decision in the US*, Regulatory Focus (Feb. 2023; Apr. 26, 2023). Excludes decisions where a data element was not disclosed or where capital structure contained cost-free items or tax credit balances. Removes cases involving Limited Issue Riders.

As shown above, when the Company's capital structure is considered along with the requested ROE of 9.9%, the resulting weighted cost of equity of 4.12% for Kentucky Power falls at the lower end of the distribution of these weighted costs of equity allowed by state regulators for other electric utilities.[7]

[7] Unlike Kentucky Power, which is an integrated electric utility, certain of the observations reflected in Figure 1 are for distribution-only utilities.

II. FUNDAMENTAL ANALYSES

Q19. What is the purpose of this section?

A19. This section briefly reviews the operations and finances of Kentucky Power. As a predicate to my quantitative analyses, it examines conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Kentucky Power

Q20. Briefly describe Kentucky Power and its utility operations.

A20. Organized in Kentucky in 1919 and headquartered in Ashland, Kentucky, Kentucky Power is a wholly-owned operating subsidiary of American Electric Power Company, Inc. ("AEP"), and is principally engaged in the generation, transmission, and distribution of electric power. The Company provides electric service to approximately 163,000 retail customers in eastern Kentucky. In addition to providing retail electric utility service, the Company also sells electric power at wholesale to municipalities. At December 31, 2022, Kentucky Power's total assets amounted to $3.0 billion, with annual revenues amounting to approximately $773 million.[8]

Kentucky Power owns 1,075 megawatts ("MW") of generating capacity, consisting of its 50% interest in the two coal-fired Mitchell Plant units (780 MW) and its natural gas-fired Big Sandy facility (295 MW). Kentucky Power's transmission and distribution facilities consist of approximately 11,200 miles of transmission and distribution lines. The Company is a member of the PJM Interconnection, LLC ("PJM"), a regional transmission organization approved by the Federal Energy Regulatory Commission ("FERC"), and provides transmission service pursuant to the PJM Open Access Transmission Tariff. Kentucky Power's retail utility operations are

[8] The information in this section is sourced from *Kentucky Power Co.*, 2022 Annual Report, and AEP Form 10-K for the fiscal year ended December 31, 2022.

subject to the jurisdiction of the Commission, with wholesale transmission operations being regulated by FERC.

Q21. What credit ratings have been assigned to Kentucky Power?

A21. Moody's has assigned the Company an issuer rating of Baa3, which is the lowest investment grade rating.[9] Meanwhile, S&P recently downgraded Kentucky Power's corporate credit rating from BBB+ to BBB.[10] Fitch Ratings, Inc. ("Fitch") has assigned an issuer default rating of BBB to the Company.

Q22. Does Kentucky Power anticipate the need for capital going forward?

A22. Yes. The Company must undertake investments for necessary maintenance and expansion of its electric utility system as it continues to provide safe and reliable service to its customers. For 2023 to 2025, Kentucky Power is estimating total capital expenditures of approximately $488 million.[11] In addition, the Company remains obligated to repay maturing long-term debt. Continued support for Kentucky Power's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

B. <u>Outlook for Capital Costs</u>

Q23. Please summarize current economic conditions.

A23. U.S. real GDP contracted 3.4% during 2020, but with the easing of COVID-19 lockdowns, the economic outlook improved significantly in 2021, with GDP growing at a pace of 5.7%. Regional increases in COVID-19 cases, expiration of government assistance payments, and declines in wholesale trade led GDP to contract in the first two quarters of 2022, while expanding exports and higher consumer spending during the last

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[9] Credit rating firms, such as Moody's, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'Aaa', 'Aa', 'A', and 'Baa' ratings are considered investment grade. Credit ratings for bonds below these designations ('Ba', 'B', 'Caa', etc.) are considered speculative grade, and are commonly referred to as "junk bonds." The term "investment grade" refers to bonds with ratings in the 'Baa' category and above.

[10] S&P Global Ratings, *American Electric Power Ratings Affirmed; Kentucky Power Downgraded To 'BBB' On Weaker Financials; Outlook Stable* (Apr. 20, 2023).

[11] Exhibit W to Section II of the Company's Application.

two quarters of 2022 resulted in GDP growth rates of 3.2% and 2.6%, respectively.[12] On a combined basis, these various influences produced a 2.1% increase in real GDP for 2022.[13] Meanwhile, indicators of employment remained stable, with the national unemployment rate falling slightly to 3.5% in March 2023.[14]

The underlying risk and price pressures associated with the COVID-19 pandemic were overshadowed by a dramatic increase in geopolitical risks following Russia's invasion of Ukraine in February 2022. These events have also been accompanied by heightened economic uncertainties as inflationary pressures due to COVID-19 supply chain disruptions were further stoked by sharp increases in global commodity prices. The substantial disruption in the energy economy and dramatic rise in inflation led to sharp declines in global equity markets as investors reacted to the related exposures. S&P concluded that:

> The balance of risks is firmly on the downside—with rapid monetary tightening potentially pushing major economies into recession; growing geopolitical tensions exacerbating Europe's energy crisis; lingering high prices pressuring costs and eroding households' purchasing power; and China grappling with structural factors that are undermining its economic growth.[15]

Stimulative monetary and fiscal policies, coupled with supply-chain disruptions and rapid price rises in the energy and commodities markets, led to increasing concern that inflation may remain significantly above the Federal Reserve's longer-run benchmark of 2%. In June 2022, Consumer Price Index ("CPI") inflation peaked at its highest level since November 1981. Since then, CPI inflation has gradually moderated to 5.0% in March 2023.[16] The so-called "core" price index, which excludes more

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[12] https://www.bea.gov/news/2023/gross-domestic-product-fourth-quarter-and-year-2022-third-estimate-gdp-industry-and (last visited Apr. 25, 2023).

[13] *Id*.

[14] https://www.bls.gov/news.release/pdf/empsit.pdf (last visited Apr. 25, 2023).

[15] S&P Global Ratings, *Global Credit Conditions Q4 2022: Darkening Horizons*, Comments (Sept. 29, 2022).

[16] https://www.bls.gov/news.release/cpi.nr0.htm (last visited Apr. 14, 2023).

volatile energy and food costs, rose at an annual rate of 5.6% in March 2023. Similarly, Personal Consumption Expenditure Price Index ("PCE") inflation rose 5.0% in February 2023, or 4.6% after excluding more volatile food and energy costs.[17] As Federal Reserve Chair Jerome H. Powell has noted:

> Although inflation has moderated recently, it remains too high. The longer the current bout of high inflation continues, the greater the chance that expectations of higher inflation will become entrenched.[18]

More recently, turmoil in the banking sector has shaken investor confidence and increased volatility in bond and equity markets. The Federal Reserve and U.S. Treasury took quick and dramatic action to shore up banks' liquidity needs and strengthen public confidence in the banking system, but as Moody's noted, "bank stress has added uncertainty to the outlook."[19]

Q24. How have these developments impacted the Federal Reserve's monetary policies?

A24. As of its policy meeting in May 2023, the Federal Open Market Committee ("FOMC") has responded to concerns over accelerating inflation by raising the benchmark range for the federal funds rate by a total of 5.00% since March 2022.[20] In addition to these increases, Chair Powell has surmised that the significant draw-down of its balance sheet holdings that began in June 2022 could be the equivalent of another one quarter percent rate hike over the course of a year.[21] Chair Powell noted that, "The process of getting inflation back down to 2 percent has a long way to go and is likely to be bumpy,"[22] with the recent banking crisis amply demonstrating these latent risks.

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[17] https://www.bea.gov/news/2023/personal-income-and-outlays-february-2023 (last visited Apr. 25, 2023).

[18] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Feb. 1, 2023), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20230201.pdf (last visited Feb. 21, 2023).

[19] Moody's Investors Service, *Baseline US macro forecasts unchanged but outlook more uncertain*, Sector Comment (Apr. 12. 2023).

[20] The FOMC is a committee composed of twelve members that serves as the monetary policymaking body of the Federal Reserve System.

[21] Federal Reserve, *Transcript of Chair Powell's Press Conference* (May 4, 2022), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20220504.pdf.

[22] https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20230322.pdf.

Q25. What impact do higher inflation expectations have on the return that equity investors require from Kentucky Power?

A25. Implicit in the required rate of return for long-term capital—whether debt or common equity—is compensation for expected inflation. This is highlighted in the textbook, *Financial Management, Theory and Practice*:

> The four most fundamental factors affecting the cost of money are (1) production opportunities, (2) time preferences for consumption, (3) risk, and (4) inflation.[23]

In other words, a part of investors' required return is intended to compensate for the erosion of purchasing power due to rising price levels. This inflation premium is added to the real rate of return (pure risk-free rate plus risk premium) to determine the nominal required return. As a result, higher inflation expectations lead to an increase in the cost of equity capital.

Q26. Have these developments impacted the risks faced by utilities and their investors?

A26. Yes. Concerns over weakening credit quality prompted S&P to revise its outlook for the regulated utility industry from "stable" to "negative."[24] As S&P explained:

> Even before the current downturn and COVID-19, a confluence of factors, including the adverse impacts of tax reform, historically high capital spending, and associated increased debt, resulted in little cushion in ratings for unexpected operating challenges.[25]

Meanwhile, higher inflation expectations also pose a challenge for utilities, with S&P recently noting that "the threat of inflation comes at a time when credit metrics are already under pressure relative to downside ratings thresholds."[26] S&P noted that "risk

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[23] Eugene F. Brigham, Louis C. Gapenski, and Michael C. Ehrhardt, *Financial Management, Theory and Practice*, Ninth Edition (1999) at 126.

[24] S&P Global Ratings, *COVID-19: The Outlook For North American Regulated Utilities Turns Negative*, RatingsDirect (Apr. 2, 2020).

[25] S&P Global Ratings, *North American Regulated Utilities Face Tough Financial Policy Tradeoffs To Avoid Ratings Pressure Amid The COVID-19 Pandemic*, RatingsDirect (May 11, 2020).

[26] S&P Global Ratings, *Will Rising Inflation Threaten North American Investor-Owned Regulated Utilities' Credit Quality?* (Jul. 20, 2021).

will continue to pressure the credit quality of the industry in 2022."[27] As S&P elaborated:

> Recently, several new credit risks have emerged, including inflation, higher interest rates, and rising commodity prices. Persistent pressure from any of these risks would likely lead to a further weakening of the industry's credit quality in 2022.[28]

Similarly, on November 10, 2022, Moody's revised its outlook for the regulated utilities sector to "negative" from "stable," citing "increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates."[29] In affirming its negative outlook on the industry, S&P recently cited weak financial measures, rising energy prices and capital spending, and increased environmental risks as key challenges, noting that, "The industry outlook remains negative and has been negative since early 2020."[30]

Q27. Do changes in utility company beta values corroborate an increase in industry risk?

A27. Yes. Beta measures a stock's price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions.

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[27] S&P Global Ratings, *For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category*, RatingsDirect (Jan. 20, 2022).

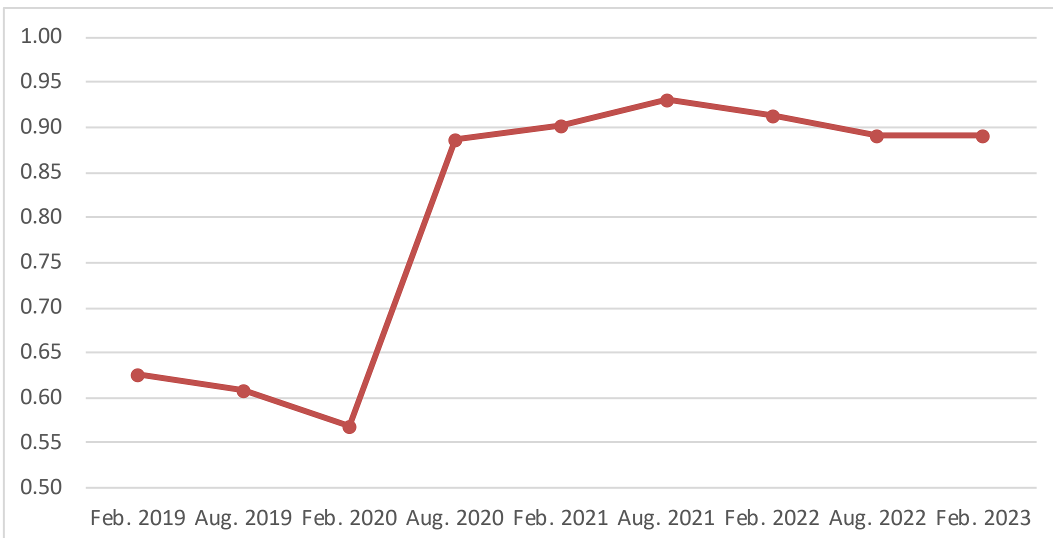
[28] *Id*.

[29] Moody's Investors Service, *Regulated Gas Utilities--US, 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates,* Outlook (Nov. 10, 2022).

[30] S&P Global Ratings, *North American Regulated Utilities, The industry's outlook remains negative*, Industry Top Trends (Jan. 23, 2023).

As shown later in my testimony in Table 2, the average beta for the Utility Group is 0.89.[31] During February 2020, the average beta for this same group of electric utilities was 0.57.[32] The significant shift in beta values for the Utility Group is further exemplified in Figure 2 below. As illustrated there, the average beta value for the Utility Group increased significantly during the second quarter of 2020, continued to increase during 2021, and has remained elevated. This dramatic increase in a primary gauge of investors' risk perceptions is further proof that the risk of utility common stocks has increased.

FIGURE 2
UTILITY GROUP BETA VALUES



Q28. Have increased risks and higher inflation resulted in higher capital costs?

A28. Yes. While the cost of equity is not directly observable, yields on long-term bonds provide a widely referenced benchmark for the direction of capital costs, including required returns on common stocks. Table 1 below compares the average yields on Treasury securities and Baa-rated public utility bonds during April 2023 with those

[31] As indicated on Exhibit AMM-7, this is based on data as of March 31, 2023.

[32] The Value Line Investment Survey, *Summary & Index* (Feb. 14, 2020).

prevailing in January 2021, when the Commission issued its final order in Case No. 2020-00174.[33]

TABLE 1
BOND YIELD TRENDS

Series	April 2023	January 2021	Change (bps)
10-Year Treasury Bonds	3.46%	1.08%	238
30-Year Treasury Bonds	3.69%	1.82%	187
Baa Utility Bonds	5.47%	3.18%	229

Source: https://fred.stlouisfed.org/series/GS30; Moody's Credit Trends.

As shown above, trends in bond yields document a substantial increase in the returns on long-term capital demanded by investors. With respect to utility bond yields—which are the most relevant indicator to gauge the impact on the cost of equity—average yields are now 229 basis points above the level prevailing at the time the Commission issued its final order in Kentucky Power's last rate proceeding.

Q29. What are the implications of these trends in evaluating a fair ROE for Kentucky Power?

A29. The upward move in interest rates suggests that long-term capital costs—including the cost of equity—have increased significantly since Kentucky Power's last rate proceeding. Exposure to rising interest rates, inflation, and capital expenditure requirements also reinforce the importance of buttressing Kentucky Power's credit standing, which is under pressure. Moody's and S&P have both noted that key measures of cash flow sufficiency for the Company have fallen below downgrade thresholds,[34] with S&P concluding that its recent decision to downgrade Kentucky Power "reflects

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[33] Case No. 2020-00174, Order (Jan. 13, 2021).

[34] Moody's Investors Service, *American Electric Power Company, Inc., Termination of Kentucky operations sale has no immediate credit impact,* Issuer Comment (Apr. 18, 2023); S&P Global Ratings, *American Electric Power Ratings Affirmed; Kentucky Power Downgraded to 'BBB' On Weaker Financials; Outlook Stable*, RatingsDirect (Apr. 20, 2023).

the company's stand-alone weakening financial measures."[35] Considering the potential for financial market instability, competition with other investment alternatives, and investors' sensitivity to risk exposures in the utility industry, credit strength is a key ingredient in maintaining access to capital at reasonable cost. Strengthening Kentucky Power's financial integrity is also imperative to ensure the ongoing capability to maintain investment grade ratings.

Q30. Would it be reasonable to disregard the changes in capital market conditions that have occurred since the Commission last established an ROE for Kentucky Power?

A30. No. They reflect the reality in which Kentucky Power must attract and retain capital. The standards underlying a fair rate of return require an authorized ROE for the Company that is competitive with other investments of comparable risk and sufficient to preserve its ability to maintain access to capital on reasonable terms. These standards can only be met by considering the requirements of investors over the time period when the rates established in this proceeding will be in effect. If the upward shift in investors' risk perceptions and required rates of return for long-term capital is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with Kentucky Power's risks will weaken its financial integrity, while hampering the Company's ability to attract the capital necessary to provide safe and reliable service.

III. COMPARABLE RISK PROXY GROUP

Q31. What is the purpose of this section of your testimony?

A31. This section explains the basis of the proxy group of publicly traded companies I use to estimate the cost of equity, examines alternative objective indicators of investment risk

[35] S&P Global Ratings, *American Electric Power Ratings Affirmed; Kentucky Power Downgraded to 'BBB' On Weaker Financials; Outlook Stable*, RatingsDirect (Apr. 20, 2023).

for these firms, and compares the investment risks applicable to Kentucky Power with my reference group.

Q32. What key principles underpin the evaluation of a proxy group?

A32. The United States Supreme Court's *Hope* and *Bluefield* decisions establish a standard of comparison between a subject utility and other companies based on comparable risk. The generally accepted approach is to select a group of companies that are of similar risk to the subject utility, and then to perform various quantitative analyses based on this proxy group to estimate investors' required returns. The results of these analyses are then used to evaluate a range of reasonableness and a final ROE recommendation for the subject utility.

Q33. As an initial matter, does the fact that Kentucky Power is a wholly owned subsidiary alter these fundamental standards?

A33. No. While the Company has no publicly traded common stock and AEP is Kentucky Power's only shareholder, this does not change the standards governing the determination of a just and reasonable ROE for the Company. Ultimately, the common equity required to support Kentucky Power's utility operations must be raised in the capital markets, where investors consider the Company's ability to offer a rate of return that is competitive with other risk-comparable alternatives. Kentucky Power competes with other investment opportunities and unless there is a reasonable expectation that investors will have the opportunity to earn returns that compensate for the underlying risks, capital will be allocated elsewhere, the Company's financial integrity will weaken, and investors will demand an even higher rate of return. Kentucky Power's ability to offer a reasonable return on investment is a necessary ingredient to ensure that customers continue to enjoy economical rates and reliable service and, by extension, the preservation of AEP's ability to attract equity capital.

A. Determination of the Proxy Group

Q34. How do you implement quantitative methods to estimate the cost of common equity for Kentucky Power?

A34. Applying quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices and beta values. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. The accepted approach to increase confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable. The results of the analysis for the proxy of companies are used to establish a range of reasonableness for the cost of equity for the specific company at issue.

Q35. How do you identify the proxy group of electric utilities relied on for your analyses?

A35. To reflect the risks and prospects associated with Kentucky Power's jurisdictional electric operations, I begin with those companies included in the Electric Utility industry groups compiled by Value Line.[36] Value Line is one of the most widely available sources of investment advisory information, and its industry groups provide an objective source to identify publicly traded firms that investors would regard to be similar in operations. I then apply the following criteria:

1. Investment grade corporate credit ratings from Moody's and S&P within one notch of the Company's current ratings, and within the investment grade scale. For Moody's, this results in a ratings range of Baa3 and Baa2; for S&P the range is BBB-, BBB, and BBB+.
2. No cuts in common dividend payments during the past six months and no announcement of a dividend cut since that time.

[2] In addition to the companies included in Value Line's electric utility industry groups, I also considered Algonquin Power & Utilities Company and Emera, Inc, which would both be regarded as comparable utility investment opportunities by investors. Neither of these companies met my required screening criteria.

3. No ongoing involvement in a major merger or acquisition that would distort quantitative results.

These criteria result in a proxy group composed of eighteen companies, which I refer to as the "Utility Group."

B. <u>Relative Risks of the Utility Group and Kentucky Power</u>

Q36. How do you evaluate investors' risk perceptions for the Utility Group?

A36. My evaluation of relative risk considers five published benchmarks that are widely relied on by investors—credit ratings from Moody's and S&P, along with Value Line's Safety Rank, Financial Strength Rating, and beta values. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide broad, objective measures of overall investment risk that are readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide a widely referenced benchmark for investment risks, they are focused on default risk specific to debtholders. Other quality rankings published by investment advisory services provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall equity risk measure is intended to capture the total risk of a stock and incorporates elements of stock price stability and financial strength. The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Value Line is one of the most widely available source of investment advisory information and these objective, published indicators provide guidance regarding the risk perceptions of investors.

As previously mentioned, beta measures a stock's price volatility relative to the market, with higher betas indicating greater risk.

Q37. How does the overall risk of your proxy group compare to Kentucky Power?

A37. Table 2 compares the Utility Group with the Company across the five key risk indicators discussed above. Because Kentucky Power has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, AEP.

TABLE 2
COMPARISON OF RISK INDICATORS

			Value Line		
	S&P	Moody's	Safety Rank	Financial Strength	Beta
Utility Group	BBB+	Baa2	2	A	0.89
Kentucky Power	BBB	Baa3	1	A+	0.75

Note: Kentucky Power's Value Line ratings are for its parent company, AEP.

Q38. What does this comparison indicate regarding investors' assessment of the relative risks associated with your utility Group?

A38. The average S&P and Moody's credit ratings corresponding to the Utility Group are higher than those of Kentucky Power, indicating somewhat less risk. While AEP's Value Line Ratings and beta indicate somewhat less risk than the Utility Group, these values are not specific to the Company.[37] Considered together, a comparison of these objective measures indicates that investors would likely conclude that the overall

[37] AEP is rated A- and Baa2 by S&P and Moody's, respectively. Given that Kentucky Power's credit ratings fall below the ratings assigned to AEP, Value Line's risk indicators for AEP are likely to understate the risk exposures associated with the Company.

investment risks for the firms in the Utility Group are generally comparable to those of Kentucky Power.

Q39. How does Kentucky Power's rating profile compare with the electric utility industry more generally?

A39. The BBB rating assigned by S&P ranks Kentucky Power below ratings for other utilities, which are predominantly rated A- or BBB+. S&P reported that of the 250 regulated utilities covered in its survey, only 56 had credit ratings falling in the BBB category or below.[38] Kentucky Power's BBB rating from Fitch also indicates greater risk than the median issuer default rating of A- for utility operating companies reported by Fitch.[39] Meanwhile, the Company's Baa3 rating from Moody's represents the lowest investment grade rating. In its most recent annual outlook for regulated electric utilities, Moody's ranks Kentucky Power's credit standing at the bottom of the range for other vertically integrated operating companies, with only one of the sixty-eight rated companies having higher risk than the Company.[40]

Q40. What is the significance of "investment grade" versus "below investment grade?"

A40. The term "investment grade" refers to a security having sufficient quality, or relatively low risk, to be suitable for certain investment purposes, and many investors are restricted by federal regulations or investment guidelines from purchasing debt securities that do not have an investment grade rating. There is a precipitous increase in risk associated with moving from investment grade to below investment grade. Credit rating differences within the investment grade range tend to reflect relatively modest differentials among fairly secure investments. Meanwhile, moving to below investment

[38] S&P Global Ratings, *Issuer Ranking: North American Electric, Gas, And Water Regulated Utilities, Strongest To Weakest*, RatingsDirect (Jan. 10, 2023).

[39] Fitch Ratings, Inc., *North American Utilities, Power & Gas Outlook 2023* (Dec. 7, 2022).

[40] Moody's Investors Service, *Regulated Electric and Gas Utilities – US, 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates*, Outlook (Nov. 10, 2022). Moody's ranks Kentucky Power as riskier than every other vertically-integrated utility with investment grade ratings. The only utility falling below Kentucky Power is Entergy New Orleans, which is rated Ba1.

grade implies an altogether different risk plateau—one where the firm is regarded as a speculative investment. Fitch observed that when credit market conditions are unsettled, "'flight to quality' is selective within the [utility] sector, favoring companies at higher rating levels."[41] The negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade. As the former Chairman of the New York State Public Service Commission noted in his role as spokesman for NARUC:

> While there is a large difference between A and BBB, there is an even brighter line between Investment Grade (BBB-/Baa3 bond ratings by S&P/Moody's, and higher) and non-Investment Grade (Junk) (BB+/Ba1 and lower). The cost of issuing non-investment grade debt, assuming the market is receptive to it, has in some cases been hundreds of basis points over the yield on investment grade securities.[42]

Q41. Are there other pressures that have particular significance for Kentucky Power?

A41. Yes. Even before the downturn attributable to the COVID-19 pandemic, the Company's service territory faced weak economic conditions and higher unemployment than national and statewide averages. Moody's observed that, "Utilities that operate in service territories with poor demographics or weak local economies are at higher risk because high inflation could limit the willingness of regulators to allow utilities to pass through their costs to customers all at once."[43] With respect to Kentucky Power specifically, Moody's noted that "the KPSC's recent decisions have been impacted by the weak economic conditions in KPCo's service territory and have been less supportive of utility credit quality."[44]

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[41] Fitch Ratings Ltd., *U.S. Utilities, Power, and Gas 2010 Outlook*, Global Power North America Special Report (Dec. 4, 2009).

[42] George Brown, *Credit and Capital Issues Affecting the Electric Power Industry*, Federal Energy Regulatory Commission Technical Conference (Jan. 13, 2009).

[43] Moody's Investors Service, *2023 outlook negative due to higher natural gas prices, inflation and rising interest rates*, Outlook (Nov. 10, 2022).

[44] Moody's Investors Service, *American Electric Power Company, Inc.*, Credit Opinion (Sep. 21, 2022).

Investors also recognize that Kentucky Power's service area is characterized by a high concentration of sales to industrial customers relative to other electric utilities. During 2022, approximately 24% of the Company's total revenues were to industrial customers,[45] versus an average of 15% for the firms in the Utility Group. Further aggravating the risks of this exposure, during 2022, 14% of Kentucky Power's revenues were attributable to a single customer, Marathon Petroleum Company.[46] Because these sales are more sensitive to business cycle changes, the price of alternative energy sources, and pressure from competitors, they are generally considered to be more risky than sales to residential or commercial customers.[47] As S&P recognized, "the company derives about half of its energy sales from industrial customers, which also leads to less stability in its operating cash flow than if its customer base was entirely residential."[48] This exposure to a relatively high concentration of industrial sales implies a significant degree of risk to Kentucky Power's operations that must be offset by sufficient financial fitness.

Q42. Please describe the concept of attrition as it relates to ratemaking.

A42. Attrition refers to a shortfall between a utility's actual return and the allowed return approved by regulators. It occurs when the assumptions regarding sales, costs, and rate base used to establish rates do not produce revenues that reflect the actual costs incurred to serve customers during the period that rates are in effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return even if the utility is operating efficiently. Similarly, when the utility's investment in utility plant exceeds the rate base used for ratemaking, the earned rate of return will fall below the allowed return through no fault of the utility's

[45] Kentucky Power Company, 2022 Annual Report at 65.

[46] *Id.* at 14.

[47] For example, Seeking Alpha reported that production at Marathon's Catlettsburg refinery was cut by as much as one-third due to lower gasoline demand stemming from the COVID-19 pandemic. Carl Surran, *Marathon raises rates at Catlettsburg as demand claws back*, Seeking Alpha (May 11, 2020).

[48] S&P Global Ratings, *Kentucky Power Co*, RatingsDirect (Oct. 28, 2021).

management. These imbalances are exacerbated as the regulatory lag increases between the period during which the data used to establish rates is measured and the date when the rates go into effect.

Q43. Would investors view attrition as an ongoing risk for Kentucky Power?

A43. Yes. Investors are concerned with what they can expect in the future, not what they might expect in theory if a historical test year were to repeat. However, as discussed in the testimony of Company Witness West, regulatory lag and attrition have been ongoing issues for Kentucky Power and the Company's earned return has fallen below its authorized return in every quarter since 2018—many times by a wide margin.[49]

Investors clearly recognize that Kentucky Power is exposed to significant risks associated with the ability to recover rising costs and investment on a timely basis. Value Line highlighted to investors that Kentucky Power "has not been earning an adequate return."[50] Moody's recently affirmed this view, noting that, "Kentucky Power is AEP's weakest utility subsidiary from a credit perspective, with cash flow that has historically been constrained by persistent underearning in an economically challenged service territory."[51]

C. <u>Regulatory Mechanisms</u>

Q44. Would investors consider the implications of regulatory mechanisms in evaluating a utility's relative risks?

A44. Yes. Decoupling mechanisms, cost trackers, and future test years have been increasingly prevalent in the utility industry, along with alternatives to traditional ratemaking such as formula rates and multi-year rate plans. As shown on Exhibit AMM-3, the companies in my Utility Group operate under a wide variety of cost adjustment

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[49] For example, in the first quarter of 2023, Kentucky Power's earned ROE was an anemic 2.88%, which falls below prevailing yields on 30-day Treasury bills.

[50] The Value Line Investment Survey, *American Elec. Pwr.* (Jun. 10, 2022).

[51] Moody's Investors Service, *American Electric Power Company, Inc., Termination of Kentucky operations sale has no immediate credit impact*, Issuer Comment (Apr. 18, 2023).

mechanisms, which encompass revenue decoupling and adjustment clauses designed to address rising capital investment outside of a traditional rate case, increasing costs of environmental compliance measures, as well as riders to address the costs of energy conservation programs, bad debt expenses, certain taxes and fees, post-retirement employee benefit costs and transmission-related charges. S&P Global Market Intelligence, *RRA Regulatory Focus* ("RRA") concluded in its most recent review of adjustment clauses that:

> More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation or delivery infrastructure to be used, effectively including these items in rate base without the need for a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.
>
> . . . [C]ertain types of adjustment clauses are more prevalent than others. For example, those that address electric fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and roughly half of the utilities have some type of decoupling mechanism in place.[52]

Q45. What regulatory mechanisms have been approved for Kentucky Power?

A45. In addition to a fuel adjustment clause, the Commission has approved a surcharge for the Company that allows for recovery of environmental compliance costs applicable to coal-fired generating facilities (the "Environmental Surcharge"). Kentucky Power also operates under a Demand Side Management ("DSM") rate mechanism that provides for recovery of the full costs associated with DSM programs—including any new revenues lost due to reduced sales—as well as riders to address certain retirement costs associated with Big Sandy Units 1 and 2 (the "Decommissioning Rider") and an offset related to the now terminated Rockport Plant Unit Power Agreement. However, in Case No. 2020-00174, the Commission prescribed a lower 9.1% ROE to be applicable to the

[52] S&P Global Market Intelligence, *Adjustment Clause: A state-by-state overview*, RRA Regulatory Focus (Jul. 18, 2022).

Environmental Surcharge and the Decommissioning Rider, eroding the benefit of these mechanisms.

Q46. Do the regulatory mechanisms approved for Kentucky Power set it apart from other firms operating in the utility industry?

A46. Yes. The mechanisms currently in place for the Company are more limited than those approved for other firms in the industry. In contrast to many of the specific operating companies associated with the firms in the Utility Group, the Commission has not approved cost tracking mechanisms to address ongoing investment in electric utility infrastructure. Nor does Kentucky Power benefit from a normalization adjustment or decoupling mechanism to insulate utility margins from weather fluctuations or declining usage.

Q47. What other considerations are relevant to investors' assessment of Kentucky Power?

A47. While recognizing that the regulatory framework is generally credit supportive for Kentucky Power, investors are also exposed to considerable uncertainty due to ongoing environmental considerations. Notwithstanding the environmental recovery riders approved for the Company, Moody's concluded that Kentucky Power remains exposed to elevated carbon transition risks due to its significant coal-fired generation.[53] Similarly, S&P has noted that the Company "continues to be exposed to coal-fired generation,"[54] and that this implies "heightened risks."[55]

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[53] Moody's Investors Service, *Kentucky Power Company*, Credit Opinion (Jun. 29, 2022).

[54] S&P Global Ratings, *Kentucky Power Co. Downgraded to 'BBB+', On CreditWatch Developing On Announced Sale By Parent American Electric Power*, RatingsDirect (Apr. 28, 2021).

[55] S&P Global Ratings, *Kentucky Power Co.*, RatingsDirect (Apr. 8, 2020).

D. Capital Structure

Q48. Is an evaluation of a utility's capital structure relevant in assessing its return on equity?

A48. Yes. Other things equal, a higher debt ratio and lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow that will remain.

Q49. What common equity ratio is implicit in Kentucky Power's capital structure?

A49. As discussed in the testimony of Company Witness Messner, the capital structure used to compute the overall rate of return for Kentucky Power includes 41.62% common equity.

Q50. How does this compare to the average equity ratios maintained by the Utility Group?

A50. As shown on page 1 of Exhibit AMM-4, common equity ratios for the individual firms in the Utility Group ranged between 33.0% and 59.6% and averaged 42.4%. Meanwhile, the three-to-five year forecasts published by Value Line result in common equity ratios ranging from 32.0% to 57.5% for the Utility Group, with an average of 43.6%.

Q51. Are there other industry benchmarks that are more relevant in evaluating Kentucky Power's capital structure?

A51. Yes. Because this proceeding focuses on the ROE for the regulated electric utility operations of Kentucky Power, the capital structures maintained by other operating electric utilities provide a consistent basis of comparison.

Q52. What capitalization ratios are maintained by comparable utility operating companies?

A52. Pages 2 and 3 of Exhibit AMM-4 display capital structure data for the group of electric utility operating companies owned by the firms in the Utility Group. As shown there, common equity ratios for these utilities range from 40.1% to 59.5% and average 51.3%. This benchmark provides a direct guide to financing policies that are consistent with industry-specific risks and the need to maintain adequate borrowing capacity and financial flexibility.

Q53. Do ongoing economic and capital market uncertainties also influence the appropriate capital structure for Kentucky Power?

A53. Yes. Financial flexibility plays a crucial role in ensuring the wherewithal of a utility to meet funding needs. Utilities with higher financial leverage may be foreclosed from or have limited access to additional borrowing, especially during times of financial market stress. As Moody's observed:

> Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to capital markets to assure adequate sources of funding and to maintain financial flexibility. During times of distress and when capital markets are exceedingly volatile and tight, liquidity becomes critically important because access to capital markets may be difficult.[56]

S&P recently reiterated these concerns, noting that:

> Because of the industry's high capital spending and consistent dividends, negative discretionary cashflow is regularly more than $100 billion annually. To fund this large deficit, the industry requires consistent access to the capital markets. Rising interest rates, decreasing equity prices, and inflation could hamper consistent access to the capital markets, potentially pressuring credit quality.[57]

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[56] Moody's Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

[57] S&P Global Ratings. *North American Regulated Utilities, The industry's outlook remains negative*, Industry Top Trends (Jan. 23, 2023).

As a result, the Company's capital structure must maintain adequate equity to preserve the flexibility necessary to maintain continuous access to capital even during times of unfavorable energy or financial market conditions.

Q54. What other factors do investors consider in their assessment of a company's capital structure?

A54. Utilities, including Kentucky Power, are facing significant capital investment plans. Coupled with the potential for turmoil in capital markets, this warrants a stronger balance sheet to deal with an uncertain environment. As S&P recently noted:

> Under our base case, we expect that by 2024 the industry's capital spending will exceed $180 billion. Because of the industry's continued robust capital spending, we expect that industry will continue to generate negative discretionary cash flow. This requires that the industry has consistent access to the capital markets to finance capital spending and dividends requirements.[58]

In addition, the investment community also considers the impact of other considerations, such as operating leases and asset retirement obligations, in its evaluation of a utility's financial standing.

A conservative financial profile, in the form of a reasonable common equity ratio, is consistent with the need to accommodate these uncertainties and maintain continuous access to capital under reasonable terms that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Q55. What does this evidence suggest with respect to Kentucky Power's proposed capital structure?

A55. Although Kentucky Power's ratemaking capital structure falls within the range of capital structure ratios indicated by industry benchmarks, the Company's common equity ratio falls significantly below the 51.3% average maintained by other electric

[58] S&P Global Ratings, *For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category*, RatingsDirect (Jan. 20, 2022).

operating companies. While I conclude that the Company's capital structure represents a reasonable mix of capital sources from which to calculate Kentucky Power's overall rate of return, Kentucky Power's relatively low common equity ratio implied greater than average financial risk.

Q56. Is this conclusion confirmed by reference to recent findings for electric utilities in other regulatory proceedings?

A56. Yes. The table below presents the common equity ratios approved for electric utilities over the eight quarters ending March 31, 2023, as reported by RRA:

TABLE 3
ELECTRIC UTILITY ALLOWED COMMON EQUITY RATIOS

	Low		High	Average
Q2-21	49.21%	--	52.07%	51.08%
Q3-21	40.00%	--	52.50%	50.15%
Q4-21	48.51%	--	55.00%	51.52%
Q1-22	48.00%	--	55.69%	51.80%
Q2-22	44.54%	--	52.00%	50.04%
Q3-22	48.29%	--	53.37%	51.19%
Q4-22	45.07%	--	58.22%	51.45%
Q1-23	42.50%	--	52.50%	50.90%
Average	45.77%	--	53.92%	51.02%

Source: S&P Global Market Intelligence, *Major Rate Case Decision*, RRA Regulatory Focus (Apr. 26, 2023, Feb. 10, 2022, & Feb., 2023). Excludes capital structures that include cost-free items.

As demonstrated in the table above, the Company's requested 41.62% common equity ratio falls well below the average based on capital structures recently approved for other electric utilities.

IV. CAPITAL MARKET ESTIMATES AND ANALYSES

Q57. What is the purpose of this section of your testimony?

A57. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe the quantitative analyses I conducted to estimate the cost of common equity for the Utility Group.

A. <u>Economic Standards</u>

Q58. What fundamental economic principle underlies the cost of equity concept?

A58. The concept of the cost of equity is based on the tenet that investors are risk averse. In capital markets where relatively risk-free assets are available (e.g., U.S. Treasury securities), investors will hold riskier assets only if they are offered an additional return, or risk premium, above the rate of return on a risk-free asset. Because all assets compete for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q59. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A59. Yes. The risk-return tradeoff can be documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q60. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A60. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets—including common stock—required rates of return cannot be observed. Yet there is every reason to believe that investors demonstrate risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q61. Is this risk-return tradeoff limited to differences between firms?

A61. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, the last investors in line are common shareholders. They share in the net earnings, if any, that remain after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q62. What are the challenges in determining a just and reasonable ROE for a utility?

A62. The actual return investors require is not directly observable. Different methodologies have been developed to estimate investors' expected return on capital, but these theoretical tools produce a range of estimates based on different assumptions and inputs. The DCF method, which is frequently referenced and relied on by regulators, is only one theoretical approach to evaluate the return investors require. There are a number of other accepted methodologies for estimating the cost of capital and the ranges produced by these approaches can vary widely.

Q63. Is it customary to consider the results of multiple methods when evaluating a just and reasonable ROE?

A63. Yes. In my experience, financial analysts and regulators routinely consider the results of alternative approaches in evaluating a fair ROE. No single method can be regarded as failsafe, with all approaches having advantages and shortcomings. As FERC has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[59] Similarly, a publication of the Society of Utility and Regulatory Financial Analysts concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[60]

As this treatise observed, "no single model is so inherently precise that it can be relied on solely to the exclusion of other theoretically sound models."[61] Similarly, *New Regulatory Finance* concluded that:

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[59] *Northwest Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 4 (1997).

[60] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 84.

[61] *Id*.

> There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors. In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities.[62]

Thus, while the DCF model is a recognized approach, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has recognized this principle:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is. . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[63]

More recently, FERC recognized the potential for any application of the DCF model to produce unreliable results.[64]

As this discussion indicates, considering the results of alternative approaches reduces the exposure to error associated with any single method. Just as investors inform their decisions through the use of alternative approaches, my evaluation of a fair ROE for the Company considered the results of multiple financial models.

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[62] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 429.

[63] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (KPSC 8/24/1990).

[64] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

Q64. What does this discussion imply with respect to estimating the ROE for a utility?

A64. Although the ROE cannot be observed directly, it is a function of the returns available from other alternatives and the risks of the investment. Because it is not readily observable, the ROE for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing alternative quantitative methods that focus on investors' required rates of return. These methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. <u>Discounted Cash Flow Analysis</u>

Q65. How is the DCF model used to estimate the cost of common equity?

A65. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[65]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

[65] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (*g*). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q66. What steps are required to apply the constant growth DCF model?

A66. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q67. How do you determine the dividend yields for the utilities in the Utility Group?

A67. I rely on Value Line's estimates of dividends to be paid by each of these utilities over the next twelve months as D_1. This annual dividend is then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Group are presented on page 1 of Exhibit AMM-5. As shown there, dividend yields for the firms in the Utility Group range from 2.5% to 5.1% and averaged 3.8%.

Q68. What is the next step in applying the constant growth DCF model?

A68. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q69. What are investors most likely to consider in developing their long-term growth expectations?

A69. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' growth expectations. Utility dividend policies reflect the need to accommodate business risks and investment requirements in the industry, as well as potential uncertainties in the capital markets. As a result, dividend growth in the utility industry generally lags growth in earnings as utilities conserve financial resources.

A measure that plays a pivotal role in determining investors' long-term growth expectations is future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q70. Do the growth rate projections of security analysts also consider historical trends?

A70. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. To the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q71. What growth rates are security analysts currently projecting for the firms in the proxy group?

A71. The earnings growth projections for each of the firms in the Utility Group reported by Value Line, IBES,[66] and Zacks Investment Research ("Zacks") are displayed on page 2 of Exhibit AMM-5.

Q72. How else are investors' expectations of future long-term growth prospects sometimes estimated when applying the constant growth DCF model?

A72. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the

[66] Formerly Institutional Brokers Estimate System, IBES growth rates are now compiled and published by Refinitiv.

proxy group are summarized on page 2 of Exhibit AMM-5, with the underlying details being presented on Exhibit AMM-6.

The sustainable growth rate analysis shown on Exhibit AMM-6 incorporates an "adjustment factor" because Value Line's reported returns are based on year-end book values. Since earnings is a flow over the year while book value is determined at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted. The adjustment factor determined in Exhibit AMM-6 is solely a means of converting Value Line's end-of-period values to an average return over the year, and the formula for this adjustment is supported in recognized textbooks and has been adopted by other regulators.[67]

Q73. Are there significant shortcomings associated with the "br+sv" growth rate?

A73. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b", "r", "s", and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value,

[67] *See,* Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 305-306; *Bangor Hydro-Electric Co. et al.*, 122 FERC ¶ 61,265 at n.12 (2008).

such as share prices, as are analysts' EPS growth forecasts.[68] The "sustainable growth" approach is included for completeness, but evidence indicates that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

Q74. What cost of common equity estimates are implied for the Utility Group using the DCF model?

A74. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit AMM-5.

Q75. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate illogical estimates at the extreme low or high end of the range?

A75. Yes. It is essential that the cost of equity estimates produced by quantitative methods pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated.

Q76. Have other regulators employed such tests?

A76. Yes. FERC has noted that adjustments are justified where applications of the DCF approach and other methods produce illogical results. FERC evaluates low-end DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[69] FERC's current practice is to exclude low-end cost of estimates that fall below the six-month average yield on Baa-rated utility bonds, plus 20% of the CAPM market risk premium.[70] In addition, FERC also excludes estimates that are "irrationally or anomalously high."[71] Similarly, the Staff of the Maryland Public Service Commission

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[68] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 307.

[69] *See, e.g.*, *Southern California Edison Co*., 131 FERC ¶ 61,020 at P 55 (2010).

[70] Based on the six-month average yield at April 2023 of 5.63% and the 7.8% market risk premium shown on Exhibit AMM-7, this implies a current low-end threshold of approximately 7.2%.

[71] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc*., 171 FERC ¶ 61,154 at P 152 (2020).

("MDPSC") has also eliminated DCF values where they do not offer a sufficient premium above the cost of debt to be attractive to an equity investor.[72]

Q77. Do you exclude any estimates at the low or high end of the range of DCF results?

A77. Yes. As highlighted on page 3 of Exhibit AMM-5, after considering these benchmarks and the distribution of individual estimates, I eliminate low-end DCF estimates ranging from 1.6% to 7.3%, as well as high-end DCF results of 19.8% and 20.4%. After removing these illogical values, the lower end of the DCF results is set by a cost of equity estimate of 7.4%, while the upper end is established by a cost of equity estimate of 12.6%. While a 12.6% cost of equity estimate may exceed the other values, low-end DCF estimates in the 7.4% to 8.1% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

Q78. What cost of equity estimates are implied by your DCF results for the Utility Group?

A78. As shown on page 3 of Exhibit AMM-5 and summarized in Table 4, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following ROE estimates:

TABLE 4
DCF RESULTS – UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	9.2%	10.1%
IBES	10.2%	9.4%
Zacks	9.5%	9.7%
br + sv	9.2%	9.3%

[72] See, *e.g.*, Maryland Public Service Commission, Case No. 9670, *Direct Testimony and Exhibits of Drew M. McAuliffe* (Dec. 2, 2021) at 15-16.

C. Capital Asset Pricing Model

Q79. Please describe the CAPM.

A79. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a firm's stock price to follow changes in the market. A stock that tends to respond less to market movements has a beta of less than 1.0, while stocks that tend to move more than the market have betas greater than 1.0. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Under the CAPM formula above, a stock's required return is a function of the risk-free rate (R_f), plus a risk premium that is scaled to reflect the relative volatility of a firm's stock price, as measured by beta (β). Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q80. Why is the CAPM approach relevant when evaluating the cost of equity for Kentucky Power?

A80. The CAPM approach (which also forms the foundation of the ECAPM) generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM (and ECAPM) provides important insight into investors' required rate of return for utility stocks.

Q81. How do you apply the CAPM to estimate the ROE?

A81. Application of the CAPM to the Utility Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented in Exhibit AMM-7. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return is estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm is obtained from Value Line, and the growth rate is equal to the average of the earnings growth projections for each firm published by IBES, Value Line, and Zacks, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. After removing companies with growth rates that were negative or greater than 20%, the weighted average of the projections for the individual firms implies an average growth rate over the next five years of 9.5%. Combining this average growth rate with a year-ahead dividend yield of 2.1% results in a current cost of common equity estimate for the market as a whole (R_m) of 11.6%. Subtracting a 3.8% risk-free rate based on the average yield on 30-year Treasury bonds for the six-months ending April 2023 produces a market equity risk premium of 7.8%.

Q82. What is the source of the beta values you use to apply the CAPM?

A82. I rely on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[73]

Q83. What else should be considered in applying the CAPM?

A83. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On average, small companies have higher returns than large ones. . . . The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[74]

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have developed size premiums that need to be added to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[75] Accordingly, my CAPM analysis also incorporates an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Utility Group.

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[73] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 71.

[74] Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at 99.

[75] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, *Stocks, Bonds, Bills and Inflation*, these size premia are now developed by Kroll and presented in its *Cost of Capital Navigator*.

Q84. What is the basis for the size adjustment?

A84. The size adjustment required in applying the CAPM is based on the finding that *after controlling for risk differences reflected in beta*, the CAPM overstates returns to companies with larger market capitalizations and understates returns for relatively smaller firms. The size adjustments utilized in my analysis are sourced from Kroll, who now publish the well-known compilation of capital market series originally developed by Professor Roger G. Ibbotson of the Yale School of Management, and most recently published by Kroll. Calculation of the size adjustments involve the following steps:

1. Divide all stocks traded on the NYSE, NYSE MKT, and NASDAQ indices into deciles based on their market capitalization.
2. Using the average beta value for each decile, calculate the implied excess return over the risk-free rate using the CAPM.
3. Compare the calculated excess returns based on the CAPM to the actual excess returns for each decile, with the difference being the increment of return that is related to firm size, or "size adjustment."

New Regulatory Finance observed that "small market-cap stocks experience higher returns than large market-cap stocks with equivalent betas," and concluded that "the CAPM understates the risk of smaller utilities, and a cost of equity based purely on a CAPM beta will therefore produce too low an estimate."[76]

Q85. What is the implied ROE for the Utility Group using the CAPM approach?

A85. As shown on Exhibit AMM-7, after adjusting for the impact of firm size, the CAPM approach implies an average ROE for the Utility Group of 11.1%.

D. Empirical Capital Asset Pricing Model

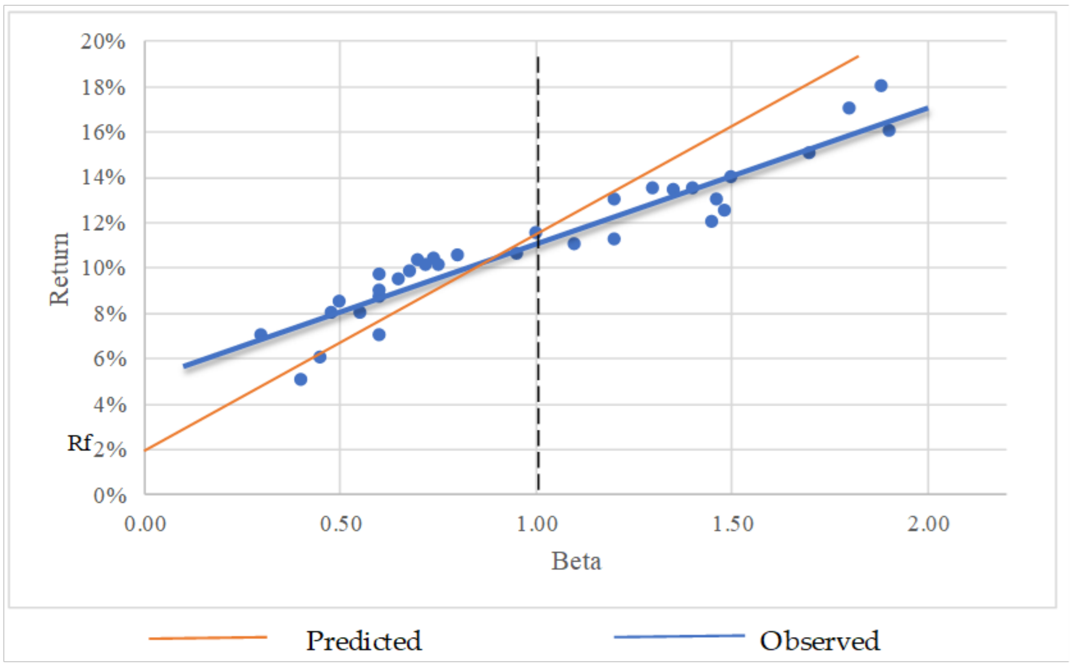
Q86. How does the ECAPM approach differ from traditional applications of the CAPM?

A86. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

[76] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 187.

In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This is illustrated graphically in the figure below:

FIGURE 3
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the Utility Group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[77]

[77] *Id.* at 189.

Based on a review of the empirical evidence, *New Regulatory Finance* concluded the expected return on a security is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

Like the CAPM formula presented earlier, the ECAPM represents a stock's required return as a function of the risk-free rate (R_f), plus a risk premium. In the formula above, this risk premium is composed of two parts: (1) the market risk premium (R_m - R_f) weighted by a factor of 25%, and (2) a company-specific risk premium based on the stock's relative volatility [$\beta_j(R_m - R_f)$] weighted by 75%. This ECAPM equation, and its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q87. Have other regulators relied on the ECAPM?

A87. Yes. Staff witnesses for the MDPSC have relied on this approach in prior testimony, noting that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluding that, "the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[78] The Staff of the Colorado Public Utilities Commission has recognized that, "The ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[79] and relied on the same ECAPM equation presented above.[80]

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[78] Maryland Public Service Commission, Case No. 9299, *Direct Testimony and Exhibits of Julie McKenna* (Oct. 12, 2012) at 9.

[79] Colorado Public Utilities Commission, Proceeding No. 13AL-0067G, *Answer Testimony and Schedules of Scott England* (July 31, 2013) at 47.

[80] *Id.* at 48.

The New York Department of Public Service also routinely incorporates the results of the ECAPM approach, which it refers to as the "zero-beta CAPM."[81] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[82]

The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this ECAPM formula,[83] as has a witness for the Office of Arkansas Attorney General.[84] In a 2018 decision, the Montana Public Service Commission determined that "[t]he evidence in this proceeding has convinced the Commission that the [ECAPM] should be the primary method for estimating . . . the cost of equity."[85]

Q88. What cost of equity estimate is indicated by the ECAPM?

A88. My application of the ECAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the CAPM. As shown on Exhibit AMM-8, applying the forward-looking ECAPM approach to the firms in the Utility Group results in an average cost of equity estimate of 11.4%, after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.

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[81] *See, e,g.,* New York Department of Public Service, Cases 19-E-0065 19-G-0066, *Prepared Fully Redacted Testimony of Staff Finance Panel* (May 2019) at 94-95.

[82] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002) at 145.

[83] Wyoming Public Service Commission, Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53.

[84] Arkansas Public Service Commission, Docket No. 17-071-U, *Direct Testimony of Marlon F. Griffing, PH.D.* (May 29, 2018) at 33-35.

[85] Montana Public Service Commission, Docket No. D2017.9.80, Order No. 7575c (Sep. 26, 2018) at P 114.

E. <u>Utility Risk Premium</u>

Q89. Briefly describe the risk premium method.

A89. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q90. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A90. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for Kentucky Power.

Q91. How do you implement the risk premium method?

A91. Estimates of equity risk premiums for utilities are based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, when considered in the context of a complete and rigorous analysis, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q92. How do you calculate the equity risk premiums based on allowed returns?

A92. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by RRA. On page 2 of Exhibit AMM-9, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2022.[86] As shown there, over this period these equity risk premiums for electric utilities average 3.89%, and the yields on public utility bonds average 7.83%.

Q93. Is there any capital market relationship that must be considered when implementing the risk premium method?

A93. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall some fraction of 1%. When implementing the risk premium method, adjustments are required to incorporate this inverse relationship if the current interest rates is different from the average interest rate over the study period.

Current bond yields are lower than those prevailing over the risk premium study period. Given that equity risk premiums move inversely with interest rates, these lower bond yields also imply an increase in the equity risk premium. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

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[86] My analysis encompasses the entire period for which published data is available.

Q94. Is this inverse relationship confirmed by published financial research?

A94. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. As summarized by *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[87]

Other regulators have also recognized that, while the cost of equity trends in the same direction as interest rates, these variables do not move in lock-step.[88] This relationship is illustrated in the figure on page 3 of Exhibit AMM-9.

Q95. What ROE is implied by the risk premium method using surveys of allowed returns?

A95. Based on the regression output between the interest rates and equity risk premiums displayed on page 3 of Exhibit AMM-9, the equity risk premium for electric utilities increases by approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit AMM-9 with an average yield on public utility bonds for the six-months ending April 2023 of 5.37%, this implies a current equity risk premium of 4.94% for electric utilities. Adding this equity risk premium to the average yield on Baa-rated utility bonds implies a current ROE of 10.57%.

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[87] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 128.

[88] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-7, https://www.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf (last visited Apr. 15, 2023); *Martha Coakley et al. v. Bangor Hydro-Elec. Co. et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

F. <u>Expected Earnings Approach</u>

Q96. What other analysis do you conduct to estimate the ROE?

A96. I also evaluate the ROE using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a just and reasonable rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q97. What economic premise underlies the expected earnings approach?

A97. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. This outcome would violate the *Hope* and *Bluefield* standards and undermine the utility's access to capital on reasonable terms.

Q98. How is the expected earnings approach typically implemented?

A98. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these projected returns on book value equity are analogous to the forward-looking allowed ROE on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices—both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q99. What ROE is indicated for Kentucky Power based on the expected earnings approach?

A99. For the firms in the Utility Group, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit AMM-10. As I explained earlier in my discussion of the br+sv growth rates used in applying the DCF model, Value Line's returns on common equity are calculated using year-end equity balances, which understates the average return earned over the year.[89] Accordingly, these year-end values were converted to average returns using the same adjustment factor

[89] For example, to compute the annual return on a passbook savings account with a beginning balance of $1,000 and an ending balance of $5,000, the interest income would be divided by the average balance of $3,000. Using the $5,000 balance at the end of the year would understate the actual return.

discussed earlier and developed on Exhibit AMM-6. As shown on Exhibit AMM-10, Value Line's projections for the Utility Group suggest an average ROE of 11.2%.

G. Flotation Costs

Q100. What other considerations are relevant in setting the return on equity for a utility?

A100. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q101. Is there an established mechanism for a utility to recognize equity issuance costs?

A101. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q102. Is there academic evidence that supports a flotation cost adjustment?

A102. The financial literature and evidence in this case provides a sound theoretical and practical basis to include consideration of flotation costs for Kentucky Power. An adjustment for flotation costs associated with past sales of common stock is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past common stock offerings has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[90] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[91]

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[90] E. F. Brigham, D. A. Aberwald, and L. C. Gapenski, *Common Equity Flotation Costs and Rate Making*, Pub. Util. Fortnightly (May 2, 1985).

[91] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 335.

Q103. Can you illustrate why investors will not have the opportunity to earn their required ROE unless a flotation cost adjustment is included?

A103. Yes. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 10.5%, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5%), and that growth is expected to be 5.5% annually. As developed in Table 5 below, if the allowed rate of return on common equity is only equal to the utility's 10.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will only be 5.25%, instead of 5.5%:

TABLE 5
NO FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.50%	$ 1.00	$ 0.50	50.0%
2	$ 9.52	$ 0.50	$ 10.02	$10.52	1.050	10.50%	$ 1.05	$ 0.53	50.0%
3	$ 9.52	$ 0.53	$ 10.55	$11.08	1.050	10.50%	$ 1.11	$ 0.55	50.0%
Growth			**5.25%**	**5.25%**			**5.25%**	**5.25%**	

The reason that investors never really earn 10.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Including a flotation cost adjustment allows investors to be fully compensated for the impact of these costs. One commonly referenced method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown in Table 6 below, by allowing a rate of return on common equity of 10.75% (a 10.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 10.5% required rate of return, since actual growth is now equal to 5.5%:

TABLE 6
INCLUDING FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.75%	$ 1.02	$ 0.50	48.9%
2	$ 9.52	$ 0.52	$ 10.04	$10.55	1.050	10.75%	$ 1.08	$ 0.53	48.9%
3	$ 9.52	$ 0.55	$ 10.60	$11.13	1.050	10.75%	$ 1.14	$ 0.56	48.9%
Growth			**5.50%**	**5.50%**			**5.50%**	**5.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether the utility is expected to issue additional shares of common stock in the future.

Q104. Are equity flotation costs particularly relevant in this proceeding?

A104. Yes. In order to finance a substantial capital expenditures program and maintain the finances of its electric utility operating company subsidiaries, including Kentucky Power, AEP will continue to rely on additional sales of common stock to raise new capital. As Moody's reported, "AEP plans to maintain the equity issuances of approximately $600 million - $700 million annually currently in its financing plan."[92] Meanwhile, Value Line projects that AEP will issue over 40 million new shares of common stock over its forecast horizon.[93]

Q105. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A105. The most common method used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. In Exhibit AMM-11, I present a survey of recent open-market common stock issues for each

[92] Moody's Investors Service, *American Electric Power Company, Inc., Termination of Kentucky operations sale has no immediate credit impact,* Issuer Comment (Apr. 18, 2023).

[93] The Value Line Investment Survey, *American Elec. Pwr.* (Mar. 10, 2023).

company in Value Line's electric and gas utility industries. For all companies in the electric and gas industries, flotation costs averaged 2.7%. This data includes AEP's 2009 public offering where it incurred issuance costs equal to approximately 3.0% of the gross proceeds. Applying the average 2.56% expense percentage for electric utilities to the Utility Group dividend yield of 3.8% produces a flotation cost adjustment on the order of 10 basis points.

Q106. Have other regulators recognized flotation costs in evaluating a fair and reasonable ROE?

A106. Yes. For example, in Docket No. UE-991606 the Washington Utilities and Transportation Commission concluded that a flotation cost adjustment of 25 basis points should be included in the allowed return on equity.[94] In Case No. INT-G-16-02 the staff of the Idaho Public Utilities Commission noted that applying a flotation cost percentage to the dividend yield "is referred to as the 'conventional' approach. Its use in regulatory proceedings is widespread, and the formula is outlined in several corporate finance textbooks."[95]

More recently, the Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, recommended a 10 basis point flotation cost adjustment.[96] Similarly, the South Dakota Public Utilities Commission has recognized the impact of issuance costs, concluding that, "recovery of reasonable flotation costs is appropriate."[97] Another example of a regulator that approves common stock issuance costs is the Mississippi Public Service Commission, which routinely includes a flotation cost adjustment in its Rate Stabilization Adjustment Rider

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[94] Washington Utilities and Transportation Commission, Docket No. UE-991606, *et al. Third Supplemental Order* (September 2000) at 95.

[95] Idaho Public Utilities Commission, Case No. INT-G-16-02, *Direct Testimony of Mark Rogers* (Dec. 16, 2016) at 18.

[96] Wyoming Public Service Commission, Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53.

[97] South Dakota Public Utilities Commission, *Northern States Power Co*, EL11-019, Final Decision and Order at P 22 (2012).

formula.[98] The Public Utilities Regulatory Authority of Connecticut[99] the Minnesota Public Utilities Commission,[100] and the Virginia State Corporation Commission[101] have also recognized that flotation costs are a legitimate expense worthy of consideration in setting a fair and reasonable ROE.

IV. NON-UTILITY BENCHMARK

Q107. What is the purpose of this section of your testimony?

A107. This section presents the results of my DCF analysis for a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis is not directly considered to arrive at my recommended ROE range of reasonableness; however, it is my opinion that this is a relevant consideration in evaluating a fair ROE for the Company.

Q108. Do utilities have to compete with non-regulated firms for capital?

A108. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only a small fraction of total common stock investment, and there is a plethora of other alternatives available to investors. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. This understanding is consistent with modern portfolio theory, which is built on the assumption that rational investors will hold a diverse portfolio of stocks and not just companies in a single industry.

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[98] *See*, *e.g.*, Entergy Mississippi Formula Rate Plan FRP-7, https://www.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf (last visited Apr. 25, 2023).

[99] *See, e.g.*, Public Utilities Regulatory Authority of Connecticut, Docket No. 14-05-06, Decision (Dec. 17, 2014) at 133-134.

[100] *See, e.g.,* Minnesota Public Utilities Commission, Docket No. E001/GR-10-276, Findings of Fact, Conclusions, and Order at 9.

[101] Virginia State Corporation Commission, Roanoke Gas Company, Case No. PUR-2018-00013, *Final Order*, (Jan. 24, 2020) at 6.

Q109. Is it consistent with the *Bluefield* and *Hope* cases to consider investors' required ROE for non-utility companies?

A109. Yes. The cost of equity capital in the competitive sector of the economy forms the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[102]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q110. Does consideration of the results for the Non-Utility Group improve the reliability of DCF results?

A110. Yes. Growth estimates used in the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. Such distortions could result in biased DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

Q111. What criteria do you apply to develop the Non-Utility Group?

A111. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

[102] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 391 (1944).

1) pay common dividends;

2) have a Safety Rank of “1”;

3) have a Financial Strength Rating of “A” or greater;

4) have a beta of 0.95 or less; and

5) have investment grade credit ratings from S&P and Moody’s.

Q112. How do you evaluate the risks of the Non-Utility Group relative to your proxy group of electric utilities?

A112. My evaluation of relative risk considers four published benchmarks that are widely relied on by investors—Value Line’s Safety Rank, Financial Strength Rating, and beta values, along with credit ratings from S&P and Moody’s. Value Line’s primary risk indicator is its Safety Rank, which ranges from “1” (Safest) to “5” (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line’s Financial Strength Ratings range from “A++” (strongest) down to “C” (weakest) in nine steps. Value Line is one of the most widely available sources of investment advisory information and these objective, published indicators provide useful guidance regarding the risk perceptions of investors. As noted earlier, beta measures a utility’s stock price volatility relative to the market as a whole, and reflects the tendency of a stock’s price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors’ risk perceptions.

Q113. How do the overall risks of your Non-Utility Group compare the proxy group of electric utilities?

A113. Table 7 compares the Non-Utility Group to the Utility Group and Kentucky Power across the four key indices of investment risk discussed above.

TABLE 7
COMPARISON OF RISK INDICATORS

			Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility Group	A-	A2	1	A+	0.80
Utility Group	BBB+	Baa2	2	A	0.89
Kentucky Power	BBB	Baa3	1	A+	0.75

Note: Kentucky Power's Value Line ratings are for its parent company, AEP.

As shown above, the risk indicators for the Non-Utility Group suggest less risk than for the Utility Group and Kentucky Power.[103]

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Johnson & Johnson, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group at 2.3%.[104] Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

[103] As I discussed previously, AEP's Value Line Ratings are not specific to the Company. The S&P and Moody's ratings confirm that the Non-Utility Group is less risky than Kentucky Power.

[104] Exhibit AMM-12 at page 1.

Q114. What are the results of your DCF analysis for the Non-Utility Group?

A114. I apply the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Utility Group, with the results being presented on page 3 of Exhibit AMM-12. As summarized in Table 8, below, after eliminating illogical values, application of the constant growth DCF model results in the following cost of equity estimates:

TABLE 8
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	10.9%	11.9%
IBES	10.4%	10.7%
Zacks	10.9%	12.1%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a fair ROE for Kentucky Power.

Q115. Does this conclude your direct testimony?

A115. Yes, it does.

VERIFICATION

The undersigned, Adrien M. McKenzie, being duly sworn, deposes and says he is the President of FINCAP, Incorporated, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Adrien M. McKenzie

State of Texas)
) Case No. 2023-00159
County of Travis)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Adrien M. McKenzie, on JUNE 25 2023.

Notary Public

BRUCE HARCUM FAIRCHILD
Notary ID #131906507
My Commission Expires
February 25, 2027

NOTARY PUBLIC STATE OF TEXAS

My Commission Expires 2/25/2027

Notary ID Number 131906507

EXHIBIT AMM-1

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrien M. McKenzie. My business address is 3907 Red River Street, Austin, Texas 78751.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a principal in FINCAP, Inc., a firm engaged primarily in financial, economic, and policy consulting in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony in over 180 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, District of Columbia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair rate of return on equity for regulated electric, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

FINCAP was formed in 1979 as an economic and financial consulting firm serving clients in both the regulated and competitive sectors. FINCAP conducts assignments ranging from broad qualitative analyses and policy consulting to technical analyses and research. The firm's experience is in the areas of public utilities, valuation of closely-held businesses, and economic evaluations (e.g., damage and cost/benefit analyses). Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I am a member of the CFA Institute. A resume containing the details of my qualifications and experience is attached below.

ADRIEN M. McKENZIE

FINCAP, INC.
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Economic and Financial Counsel

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA®) designation. He has over 30 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

President
FINCAP, Inc.
(June 1984 to June 1987)
(April 1988 to present)

Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.

Manager,
McKenzie Energy Company
(Jan. 1981 to May. 1984)

Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA®) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and sponsored prefiled testimony submitted in over 150 regulatory proceedings. In addition to filings before regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"), and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE. Other representative assignments have included developing cost of service and cost allocation studies, the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

SUMMARY OF RESULTS

Method	Average
DCF	
Value Line	9.2%
IBES	10.2%
Zacks	9.5%
Internal br + sv	9.2%
CAPM	11.1%
ECAPM	11.4%
Utility Risk Premium	10.6%
Expected Earnings	11.2%

ROE Recommendation			
Cost of Equity	10.0%	--	11.0%
Flotation Cost Adjustment			
Electric Group Dividend Yield		3.84%	
Flotation Cost Expense Factor		2.56%	
Flotation Cost Adjustment		0.10%	
Recommended ROE Range			
Range	**10.1%**	**--**	**11.1%**
Midpoint		**10.6%**	

REGULATORY MECHANISMS

UTILITY GROUP

		Type of Adjustment Clause (a)										(b)	(c)
			Conserv.			New Capital						Future	Formula
			Program	Decoupling		Trad.	Renewables/	Delivery	Environ.	Trans.		Test	Rates /
	Company	**Fuel/PPA**	**Expense**	**Full**	**Partial**	**Generation**	**Non-Trad.**	**Infra.**	**Compliance**	**Costs**		**Year**	**MRP**
1	Avista Corp.	✓	✓	✓	--	--	--	--	--	--		P	✓
2	Black Hills Corp.	✓	✓	--	✓	✓	✓	--	✓	✓		O	✓
3	CenterPoint Energy	✓	✓	--	✓	--	--	✓	✓	✓		--	✓
4	CMS Energy Corp.	✓	✓	--	--	--	✓	--	--	✓		C	--
5	Dominion Energy	✓	✓	--	--	✓	✓	✓	✓	✓		--	✓
6	DTE Energy Co.	✓	✓	--	--	--	✓	--	--	✓		C	--
7	Duke Energy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓		C,O,P	✓
8	Edison International	✓	--	✓	--	--	--	--	--	--		C	✓
9	Emera Inc.	✓	✓	--	--	✓	✓	--	✓	--		C	✓
10	Entergy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓		O,P	✓
11	Exelon Corp.	D	✓	✓	✓	--	✓	✓	✓	✓		O,P	✓
12	Hawaiian Elec.	✓	✓	--	--	--	✓	--	--	--		C	✓
13	IDACORP, Inc.	✓	✓	✓	--	--	--	--	--	--		C,P	--
14	NorthWestern Corp.	✓	✓	--	--	--	--	--	--	--		--	--
15	Otter Tail Corp.	✓	✓	--	--	✓	✓	✓	✓	✓		C,O	✓
16	Pub Sv Enterprise Grp.	D	✓	--	✓	--	--	✓	✓	--		P	--
17	Sempra Energy	✓	✓	✓	--	--	--	✓	--	✓		C	✓
18	Southern Company	✓	--	--	✓	✓	✓	--	✓	--		C,O	✓

Notes

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

Source: Exhibit AMM-3, pages 2-4, contain operating company data that are aggregated into the parent company data on this page.

ELECTRIC GROUP OPERATING COS.

			Type of Adjustment Clause (a)									(b)	(c)
				Conserv.			New Capital					Future	Formula
				Program	Decoupling		Trad.	Renewables/	Delivery	Environ.	Trans.	Test	Rates /
	Company	State	Fuel/PPA	Expense	Full	Partial	Generation	Non-Trad.	Infra.	Compliance	Costs	Year	MRP
1	**AVISTA CORP.**												
	Alaska Electric Light & Power Co.	AK	✓	--	--	--	--	--	--	--	--	--	--
	Avista Corp.	ID	✓ *	✓	✓ *	--	--	--	--	--	--	P	--
	Avista Corp.	WA	✓ *	✓	✓	-- *	--	--	--	--	--	--	✓
2	**BLACK HILLS CORP.**												
	Black Hills Colorado Electric Inc.	CO	✓	✓	--	--	✓ *	✓	--	--	✓	--	✓
	Black Hills Power Inc.	SD	✓	--	--	--	--	--	--	✓ *	✓ *	--	--
	Cheyenne Light Fuel & Power Co.	WY	✓	✓	--	✓ *	--	--	--	--	--	O	--
3	**CENTERPOINT ENERGY**												
	Southern Indiana Gas & Electric Co.	IN	✓	✓	--	✓ *	--	--	✓ *	✓ *	✓	--	✓
	CenterPoint Energy Houston Electric LLC	TX	-- *	✓	--	--	--	--	✓	--	✓	--	✓
4	**CMS ENERGY**												
	Consumers Energy Co.	MI	✓	✓	-- *	--	--	✓	--	--	✓ *	C	--
5	**DOMINION ENERGY**												
	Virginia Electric & Power Co.	NC	✓	✓ *	--	-- *	--	✓ *	--	✓	--	--	--
	Dominion Energy South Carolina	SC	✓	✓	--	--	✓ *	--	--	✓	--	--	✓
	Virginia Electric & Power Co.	VA	✓	✓	--	--	✓	✓	✓	✓	✓	--	✓
6	**DTE ENERGY CO.**												
	DTE Electric Co.	MI	✓	✓	-- *	--	--	✓	--	--	✓ *	C	--
7	**DUKE ENERGY**												
	Duke Energy Florida LLC	FL	✓	✓	--	--	✓ *	✓ *	-- *	✓	--	C	✓
	Duke Energy Indiana LLC	IN	✓	✓	--	✓ *	--	✓	✓ *	✓ *	✓	--	✓
	Duke Energy Kentucky Inc.	KY	✓	✓	--	✓ *	--	--	--	✓	--	O	--
	Duke Energy Carolinas LLC	NC	✓	✓ *	--	-- *	--	✓ *	--	✓	--	--	--
	Duke Energy Progress LLC	NC	✓	✓ *	--	-- *	--	✓ *	--	✓	--	--	--
	Duke Energy Ohio Inc.	OH	D *	✓ *	--	✓ *	--	✓	✓ *	--	✓	P	✓
	Duke Energy Progress LLC	SC	✓	✓	--	--	-- *	--	--	✓	--	--	✓
	Duke Energy Carolinas LLC	SC	✓	✓	--	--	-- *	--	--	✓	--	--	✓
8	**EDISON INTERNATIONAL**												
	Southern California Edison Co.	CA	✓	--	✓	--	--	--	--	--	--	C	✓
9	**EMERA INC.**												
	Tampa Electric Co.	FL	✓	✓	--	--	✓ *	✓ *	-- *	✓	--	C	✓

REGULATORY MECHANISMS

ELECTRIC GROUP OPERATING COS.

	Company	State	Type of Adjustment Clause (a): Fuel/PPA	Conserv. Program Expense	Decoupling: Full	Decoupling: Partial	New Capital: Trad. Generation	New Capital: Renewables/ Non-Trad.	New Capital: Delivery Infra.	New Capital: Environ. Compliance	Trans. Costs	(b) Future Test Year	(c) Formula Rates / MRP
10	**ENTERGY CORP.**												
	Entergy Arkansas LLC	AR	✓	✓	--	✓ *	✓ *	✓ *	✓ *	--	✓	P	✓
	Entergy New Orleans LLC	LA	✓	✓	--	--	--	✓	--	✓ *	✓ *	O	✓
	Entergy Louisiana LLC	LA	✓	✓ *	--	✓ *	--	--	--	✓	--	O	✓
	Entergy Mississippi LLC	MS	✓	--	--	✓ *	--	--	--	--	✓	O	✓
	Entergy Texas Inc.	TX	✓ *	✓	--	--	✓ *	--	✓	--	✓	--	✓
11	**EXELON CORP.**												
	Delmarva Power & Light Co.	DE	D *	✓	--	--	--	--	✓ *	--	✓	P	--
	Potomac Electric Power Co.	DC	D *	--	--	✓ *	--	✓ *	✓ *	--	--	P	--
	Commonwealth Edison Co.	IL	D *	✓	--	--	--	✓	✓ *	✓ *	✓	O	✓
	Baltimore Gas & Electric Co.	MD	D *	✓	✓	--	--	--	--	--	--	P	--
	Delmarva Power & Light Co.	MD	D *	✓	✓	--	--	--	--	--	--	P	--
	Potomac Electric Power Co.	MD	D *	✓	✓	--	--	--	✓ *	--	--	P	--
	Atlantic City Electric Co.	NJ	D *	✓ *	--	✓ *	--	--	✓ *	✓ *	--	P	--
	PECO Energy Co.	PA	D *	✓	--	--	--	--	✓ *	--	✓	O	--
12	**HAWAIIAN ELEC.**												
	Hawaiian Electric Co.	HI	✓	✓	--	--	--	✓ *	--	--	--	C	✓
	Hawaii Electric Light Co.	HI	✓	✓	--	--	--	--	--	--	--	C	✓
	Maui Electric Co.	HI	✓	✓	--	--	--	✓ *	--	--	--	C	✓
13	**IDACORP, INC.**												
	Idaho Power Co.	ID	✓ *	✓	✓ *	--	--	--	--	--	--	P	--
	Idaho Power Co.	OR	✓	✓	--	--	--	--	--	--	--	C	--
14	**NORTHWESTERN CORP.**												
	NorthWestern Corp.	MT	✓ *	✓	--	--	--	--	--	--	--	--	--
	NorthWestern Corp.	SD	✓	✓	--	--	--	--	--	--	--	--	--
15	**OTTER TAIL CORP.**												
	Otter Tail Power Co.	MN	✓	✓	--	--	--	✓	--	✓	✓	C	--
	Otter Tail Power Co.	ND	✓	--	--	--	✓ *	✓ *	✓ *	✓ *	✓ *	O	✓
	Otter Tail Power Corp.	SD	✓	✓	--	--	✓ *	--	✓	✓	--	--	--
16	**PUB SV ENTERPRISE GRP**												
	Public Service Electric & Gas Co.	NJ	D *	✓ *	--	✓ *	--	--	✓ *	✓ *	--	P	--
17	**SEMPRA ENERGY**												
	San Diego Gas & Electric Co.	CA	✓	--	✓	--	--	--	--	--	--	C	✓
	Oncor Electric Delivery Co.	TX	D *	✓	--	--	--	--	✓	--	✓	--	✓

ELECTRIC GROUP OPERATING COS.

		Type of Adjustment Clause (a)									(b)	(c)
			Conserv. Program	Decoupling		New Capital					Future Test	Formula Rates /
Company	State	Fuel/PPA	Expense	Full	Partial	Trad. Generation	Renewables/ Non-Trad.	Delivery Infra.	Environ. Compliance	Trans. Costs	Year	MRP
18 **SOUTHERN CO.**												
Alabama Power Co.	AL	✓ *	--	--	--	✓ *	✓	--	✓ *	--	C	✓
Georgia Power Co.	GA	✓	--	--	--	✓ *	--	--	✓ *	--	C	✓
Mississippi Power Co.	MS	✓	--	--	✓ *	--	--	--	✓ *	--	O	✓

(a) S&P Global Market Intelligence, *Adjustment clauses: A state by state overview* , Regulatory Focus Topical Special Report (Jul. 18, 2022).

(b) Edison Electric Institute, *Alternative Regulation for Emerging Utility Challenges: 2015 Update* (Nov. 11, 2015).

(c) Formula rates and Multiyear Rate plans approved in the state listed for this operating company. *See* , U.S. Department of Energy, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities* ,GRID Modernization Laboratory Consortium (Jul. 2017); The Brattle Group, *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates* , Joint Utilities of Maryland

Notes

D - Delivery-only utility.

C - Fully-forecasted test years commonly used in the state listed for this operating company.

O - Fully-forecasted test years occasionally used in the state listed for this operating company.

P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.

* For additional context around the specific recovery mechanisms available to the particular operating companies in each state, see the source document.

CAPITAL STRUCTURE

UTILITY GROUP

		At Year-end 2022 (a)			Value Line Projected (b)		
	Company	**Debt**	**Preferred**	**Common Equity**	**Debt**	**Preferred**	**Common Equity**
1	Avista Corp.	49.6%	0.0%	50.4%	48.5%	0.0%	51.5%
2	Black Hills Corp.	57.2%	0.0%	42.8%	50.0%	0.0%	50.0%
3	CenterPoint Energy	61.9%	3.0%	35.1%	55.0%	2.5%	42.5%
4	CMS Energy Corp.	65.2%	1.0%	33.8%	61.5%	1.0%	37.5%
5	Dominion Energy	60.2%	2.5%	37.2%	57.0%	2.0%	41.0%
6	DTE Energy Co.	63.4%	0.0%	36.6%	61.0%	0.0%	39.0%
7	Duke Energy Corp.	57.9%	1.6%	40.5%	61.0%	1.5%	37.5%
8	Edison International	62.8%	4.2%	33.0%	60.5%	7.5%	32.0%
9	Emera Inc.	58.8%	5.1%	36.1%	57.0%	0.0%	43.0%
10	Entergy Corp.	66.1%	0.6%	33.3%	67.0%	0.0%	33.0%
11	Exelon Corp.	60.0%	0.0%	40.0%	64.5%	0.0%	35.5%
12	Hawaiian Elec.	57.9%	0.6%	41.4%	50.0%	0.5%	49.5%
13	IDACORP, Inc.	43.8%	0.0%	56.2%	50.0%	0.0%	50.0%
14	NorthWestern Corp.	48.3%	0.0%	51.7%	49.0%	0.0%	51.0%
15	Otter Tail Corp.	40.4%	0.0%	59.6%	42.5%	0.0%	57.5%
16	Pub Sv Enterprise Grp.	56.8%	0.0%	43.2%	54.5%	0.0%	45.5%
17	Sempra Energy	44.9%	1.6%	53.5%	46.0%	1.5%	52.5%
18	Southern Company	61.4%	0.0%	38.6%	63.0%	0.0%	37.0%
	Minimum	**40.4%**	**0.0%**	**33.0%**	**42.5%**	**0.0%**	**32.0%**
	Maximum	**66.1%**	**5.1%**	**59.6%**	**67.0%**	**7.5%**	**57.5%**
	Average	**56.5%**	**1.1%**	**42.4%**	**55.4%**	**0.9%**	**43.6%**

(a) 2022 SEC Form 10-K reports.

(b) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).

UTILITY GROUP OPERATING COS.

	Operating Company	At Year-End 2022 (a) Debt	Preferred	Common Equity
1	**BLACK HILLS CORP.**			
	Black Hills Power	49.9%	0.0%	50.1%
	Cheyenne Light Fuel & Power	57.2%	0.0%	42.8%
	Black Hills/Colorado Electric Utility Co	52.1%	0.0%	47.9%
2	**CENTERPOINT ENERGY**			
	Centerpoint Energy Houston Electric	56.0%	0.0%	44.0%
3	**CMS ENERGY**			
	Consumers Energy Co.	50.2%	0.2%	49.6%
4	**DOMINION ENERGY**			
	Virginia Electric & Power	48.4%	0.0%	51.6%
	Dominion Energy South Carolina	45.2%	0.0%	54.8%
5	**DTE ENERGY CO.**			
	DTE Electric Co.	50.0%	0.0%	50.0%
6	**DUKE ENERGY**			
	Duke Energy Carolinas	48.0%	0.0%	52.0%
	Duke Energy Florida	51.8%	0.0%	48.2%
	Duke Energy Indiana	47.8%	0.0%	52.2%
	Duke Energy Ohio	40.5%	0.0%	59.5%
	Duke Energy Progress	51.8%	0.0%	48.2%
	Duke Energy Kentucky	47.0%	0.0%	53.0%
7	**EDISON INTERNATIONAL**			
	Southern California Edison Co.	55.8%	4.1%	40.1%
8	**EMERA INC.**			
	Tampa Electric Co.	41.9%	0.0%	58.1%
9	**ENTERGY CORP.**			
	Entergy Arkansas Inc.	52.4%	0.0%	47.6%
	Entergy Louisiana LLC	53.0%	0.0%	47.0%
	Entergy Mississippi Inc.	53.3%	0.0%	46.7%
	Entergy New Orleans Inc.	52.4%	0.0%	47.6%
	Entergy Texas Inc.	51.9%	0.7%	47.4%
10	**EVERGY, INC.**			
	Evergy Metro	47.9%	0.0%	52.1%
	Evergy Kansas Central	46.6%	0.0%	53.4%
11	**EXELON CORP.**			
	Delmarva Power and Light	49.8%	0.0%	50.2%
	Baltimore Gas & Electric Co.	46.0%	0.0%	54.0%
	Commonweath Edison Co.	44.5%	0.0%	55.5%
	PECO Energy Co.	46.3%	0.0%	53.7%
	Potomac Electric Power Co.	49.8%	0.0%	50.2%
	Atlantic City Electric Co.	50.1%	0.0%	49.9%

UTILITY GROUP OPERATING COS.

		At Year-End 2022 (a)		
	Operating Company	**Debt**	**Preferred**	**Common Equity**
12	**HAWAIIAN ELEC.**			
	Hawaiian Electric Co.	41.5%	0.8%	57.7%
13	**IDACORP**			
	Idaho Power Co.	45.5%	0.0%	54.5%
14	**NORTHWESTERN CORP.**			
	NorthWestern Corporation	49.7%	0.0%	50.3%
15	**OTTER TAIL CORP.**			
	Otter Tail Power Co.	45.1%	0.0%	54.9%
16	**PUB SV ENTERPRISE GRP**			
	Pub Service Electric & Gas Co.	44.7%	0.0%	55.3%
17	**SEMPRA ENERGY**			
	San Diego Gas & Electric	49.8%	0.0%	50.2%
	Oncor Electric Delivery	43.3%	0.0%	56.7%
18	**SOUTHERN CO.**			
	Alabama Power Co.	47.6%	0.0%	52.4%
	Georgia Power Co.	44.2%	0.0%	55.8%
	Mississippi Power Co.	44.4%	0.0%	55.6%

Minimum	**40.5%**	**0.0%**	**40.1%**
Maximum	**57.2%**	**4.1%**	**59.5%**
Average	**48.5%**	**0.2%**	**51.3%**

(a) 2022 SEC Form 10-K and FERC Form 1 reports.

DIVIDEND YIELD

		(a)	(b)	
	Company	**Price**	**Dividends**	**Yield**
1	Avista Corp.	$ 41.11	$ 1.84	4.5%
2	Black Hills Corp.	$ 61.80	$ 2.50	4.0%
3	CenterPoint Energy	$ 28.46	$ 0.76	2.7%
4	CMS Energy Corp.	$ 60.10	$ 1.95	3.2%
5	Dominion Energy	$ 55.51	$ 2.75	5.0%
6	DTE Energy Co.	$ 108.71	$ 3.81	3.5%
7	Duke Energy Corp.	$ 95.49	$ 4.02	4.2%
8	Edison International	$ 67.47	$ 2.95	4.4%
9	Emera Inc.	$ 54.30	$ 2.76	5.1%
10	Entergy Corp.	$ 104.69	$ 4.28	4.1%
11	Exelon Corp.	$ 41.21	$ 1.44	3.5%
12	Hawaiian Elec.	$ 39.02	$ 1.44	3.7%
13	IDACORP, Inc.	$ 104.16	$ 3.16	3.0%
14	NorthWestern Corp.	$ 56.81	$ 2.56	4.5%
15	Otter Tail Corp.	$ 69.99	$ 1.76	2.5%
16	Pub Sv Enterprise Grp.	$ 59.49	$ 2.28	3.8%
17	Sempra Energy	$ 149.16	$ 4.80	3.2%
18	Southern Company	$ 65.96	$ 2.72	4.1%
	Average			**3.8%**

(a) Average of closing prices for 30 trading days ended Mar. 29, 2023.
(b) The Value Line Investment Survey, Summary & Index (Mar. 31, 2023).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Avista Corp.	3.5%	5.2%	5.2%	4.3%
2	Black Hills Corp.	6.0%	5.4%	2.2%	6.2%
3	CenterPoint Energy	6.5%	-1.1%	7.0%	4.9%
4	CMS Energy Corp.	6.5%	8.0%	8.0%	6.5%
5	Dominion Energy	4.0%	6.1%	14.9%	5.9%
6	DTE Energy Co.	4.5%	7.4%	6.0%	6.2%
7	Duke Energy Corp.	5.0%	5.3%	5.4%	3.6%
8	Edison International	16.0%	7.0%	3.0%	6.7%
9	Emera Inc.	7.5%	4.3%	n/a	4.5%
10	Entergy Corp.	0.5%	6.6%	6.0%	3.2%
11	Exelon Corp.	n/a	6.3%	6.6%	4.5%
12	Hawaiian Elec.	4.5%	1.3%	3.1%	4.6%
13	IDACORP, Inc.	4.5%	3.0%	3.0%	3.6%
14	NorthWestern Corp.	3.5%	4.5%	1.7%	3.5%
15	Otter Tail Corp.	4.5%	9.0%	n/a	4.7%
16	Pub Sv Enterprise Grp.	4.5%	2.4%	4.3%	4.9%
17	Sempra Energy	7.0%	4.1%	5.4%	4.7%
18	Southern Company	6.5%	7.3%	4.0%	6.8%

(a) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(b) www.finance.yahoo.com (retreived Mar. 30, 2023).
(c) www.zacks.com (retrieved Mar. 30, 2023).
(d) See Exhibit AMM-6.

COST OF EQUITY ESTIMATES

	Company	V Line (a)	IBES (a)	Zacks (a)	br+sv Growth (a)
1	Avista Corp.	8.0%	9.7%	9.7%	8.8%
2	Black Hills Corp.	10.0%	9.4%	6.2%	10.2%
3	CenterPoint Energy	9.2%	1.6%	9.7%	7.6%
4	CMS Energy Corp.	9.7%	11.2%	11.3%	9.8%
5	Dominion Energy	9.0%	11.0%	19.8%	10.9%
6	DTE Energy Co.	8.0%	10.9%	9.5%	9.7%
7	Duke Energy Corp.	9.2%	9.5%	9.6%	7.8%
8	Edison International	20.4%	11.4%	7.3%	11.0%
9	Emera Inc.	12.6%	9.4%	n/a	9.6%
10	Entergy Corp.	4.6%	10.7%	10.1%	7.3%
11	Exelon Corp.	n/a	9.8%	10.1%	7.9%
12	Hawaiian Elec.	8.2%	5.0%	6.8%	8.3%
13	IDACORP, Inc.	7.5%	6.0%	6.0%	6.7%
14	NorthWestern Corp.	8.0%	9.0%	6.2%	8.1%
15	Otter Tail Corp.	7.0%	11.5%	n/a	7.2%
16	Pub Sv Enterprise Grp.	8.3%	6.2%	8.2%	8.7%
17	Sempra Energy	10.2%	7.4%	8.6%	7.9%
18	Southern Company	10.6%	11.4%	8.1%	10.9%
	Average (b)	**9.2%**	**10.2%**	**9.5%**	**9.2%**

(a) Sum of dividend yield (Exhibit AMM-5, p. 1) and respective growth rate (Exhibit AMM-5, p. 2).
(b) Excludes highlighted values.

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		(a)	(a)	(a)	(b)	(c)	(d)	(e)		(f)	(g)		
		2027					Adjustment			"sv" Factor			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	Avista Corp.	$2.85	$2.05	$34.95	28.1%	8.2%	1.0305	8.4%	2.4%	0.0498	0.3922	1.95%	4.3%
2	Black Hills Corp.	$5.25	$2.95	$50.75	43.8%	10.3%	1.0297	10.7%	4.7%	0.0340	0.4514	1.53%	6.2%
3	CenterPoint Energy	$1.85	$0.95	$19.00	48.6%	9.7%	1.0187	9.9%	4.8%	0.0025	0.3667	0.09%	4.9%
4	CMS Energy Corp.	$3.75	$2.30	$26.00	38.7%	14.4%	1.0105	14.6%	5.6%	0.0148	0.6000	0.89%	6.5%
5	Dominion Energy	$5.10	$3.30	$43.40	35.3%	11.8%	1.0392	12.2%	4.3%	0.0305	0.5308	1.62%	5.9%
6	DTE Energy Co.	$8.30	$4.65	$60.75	44.0%	13.7%	1.0192	13.9%	6.1%	0.0007	0.5881	0.04%	6.2%
7	Duke Energy Corp.	$6.80	$4.30	$70.00	36.8%	9.7%	1.0133	9.8%	3.6%	0.0004	0.4043	0.02%	3.6%
8	Edison International	$6.30	$3.50	$47.45	44.4%	13.3%	1.0337	13.7%	6.1%	0.0106	0.5255	0.55%	6.7%
9	Emera Inc.	$4.70	$3.06	$45.35	34.9%	10.4%	1.0105	10.5%	3.7%	0.0185	0.4503	0.83%	4.5%
10	Entergy Corp.	$6.50	$5.00	$73.00	23.1%	8.9%	1.0289	9.2%	2.1%	0.0277	0.3787	1.05%	3.2%
11	Exelon Corp.	$3.00	$1.80	$28.75	40.0%	10.4%	0.9820	10.2%	4.1%	0.0078	0.4524	0.35%	4.5%
12	Hawaiian Elec.	$2.60	$1.60	$25.50	38.5%	10.2%	1.0209	10.4%	4.0%	0.0124	0.4632	0.57%	4.6%
13	IDACORP, Inc.	$6.10	$4.00	$67.30	34.4%	9.1%	1.0238	9.3%	3.2%	0.0101	0.4272	0.43%	3.6%
14	NorthWestern Corp.	$4.00	$2.68	$50.00	33.0%	8.0%	1.0277	8.2%	2.7%	0.0361	0.2308	0.83%	3.5%
15	Otter Tail Corp.	$3.65	$2.20	$34.25	39.7%	10.7%	1.0195	10.9%	4.3%	0.0079	0.4731	0.37%	4.7%
16	Pub Sv Enterprise Grp.	$4.50	$2.80	$33.75	37.8%	13.3%	1.0151	13.5%	5.1%	(0.0037)	0.5645	-0.21%	4.9%
17	Sempra Energy	$11.25	$5.82	$102.65	48.3%	11.0%	1.0224	11.2%	5.4%	(0.0145)	0.4736	-0.69%	4.7%
18	Southern Company	$5.15	$3.10	$32.25	39.8%	16.0%	1.0216	16.3%	6.5%	0.0050	0.6206	0.31%	6.8%

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		(a)	(a)	(h)	(a)	(a)	(h)	(i)	(a)	(a)		(j)	(a)	(a)	(i)
		2022			2027			Chg	2027				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2022	2027	Growth
1	Avista Corp.	52.5%	$4,105	$2,155	51.5%	$5,675	$2,923	6.3%	$65.0	$50.0	$57.5	1.645	71.50	83.00	3.03%
2	Black Hills Corp.	40.3%	$6,914	$2,786	50.0%	$7,500	$3,750	6.1%	$105.0	$80.0	$92.5	1.823	64.74	71.00	1.86%
3	CenterPoint Energy	39.0%	$25,675	$10,013	42.5%	$28,400	$12,070	3.8%	$35.0	$25.0	$30.0	1.579	628.92	634.00	0.16%
4	CMS Energy Corp.	34.5%	$20,350	$7,021	37.5%	$20,800	$7,800	2.1%	$75.0	$55.0	$65.0	2.500	291.30	300.00	0.59%
5	Dominion Energy	38.5%	$66,344	$25,542	41.0%	$92,200	$37,802	8.2%	$105.0	$80.0	$92.5	2.131	810.40	870.00	1.43%
6	DTE Energy Co.	37.0%	$28,000	$10,360	39.0%	$32,200	$12,558	3.9%	$170.0	$125.0	$147.5	2.428	205.69	206.00	0.03%
7	Duke Energy Corp.	43.1%	$109,744	$47,300	37.5%	$144,100	$54,038	2.7%	$135.0	$100.0	$117.5	1.679	769.00	770.00	0.03%
8	Edison International	33.2%	$41,959	$13,930	32.0%	$61,000	$19,520	7.0%	$120.0	$80.0	$100.0	2.107	380.38	390.00	0.50%
9	Emera Inc.	42.1%	$27,171	$11,427	43.0%	$29,490	$12,690	2.1%	$95.0	$70.0	$82.5	1.819	266.00	279.80	1.02%
10	Entergy Corp.	35.2%	$36,810	$12,957	33.0%	$52,410	$17,295	5.9%	$135.0	$100.0	$117.5	1.610	211.18	230.00	1.72%
11	Exelon Corp.	49.1%	$70,107	$34,423	35.5%	$81,000	$28,755	-3.5%	$60.0	$45.0	$52.5	1.826	979.00	1000.00	0.43%
12	Hawaiian Elec.	52.8%	$4,524	$2,389	49.5%	$5,950	$2,945	4.3%	$55.0	$40.0	$47.5	1.863	109.31	113.00	0.67%
13	IDACORP, Inc.	57.2%	$4,669	$2,671	50.0%	$6,775	$3,388	4.9%	$130.0	$105.0	$117.5	1.746	50.52	52.00	0.58%
14	NorthWestern Corp.	47.8%	$4,893	$2,339	51.0%	$6,050	$3,086	5.7%	$75.0	$55.0	$65.0	1.300	54.06	62.00	2.78%
15	Otter Tail Corp.	58.5%	$2,041	$1,194	57.5%	$2,525	$1,452	4.0%	$75.0	$55.0	$65.0	1.898	41.63	42.50	0.41%
16	Pub Sv Enterprise Grp.	48.7%	$29,657	$14,443	45.5%	$36,900	$16,790	3.1%	$85.0	$70.0	$77.5	2.296	504.00	500.00	-0.16%
17	Sempra Energy	53.3%	$47,069	$25,088	52.5%	$59,800	$31,395	4.6%	$225.0	$165.0	$195.0	1.900	316.92	305.00	-0.76%
18	Southern Company	35.6%	$78,285	$27,869	37.0%	$93,500	$34,595	4.4%	$100.0	$70.0	$85.0	2.636	1060.00	1070.00	0.19%

(a) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(b) "b" is the retention ratio, computed as (EPS-DPS)/EPS.
(c) "r" is the rate of return on book equity, computed as EPS/BVPS.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2027 and Adjustment Factor.
(f) Product of change in common shares outstanding and M/B Ratio.
(g) Computed as 1 - B/M Ratio.
(h) Product of total capital and equity ratio.
(i) Five-year rate of change.
(j) Average of High and Low expected market prices divided by 2027 BVPS.

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		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	CAPM Result
1	Avista Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$3,200	0.93%	11.8%
2	Black Hills Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$4,600	0.58%	11.8%
3	CenterPoint Energy	2.1%	9.5%	11.6%	3.8%	7.8%	1.10	12.4%	$17,900	0.45%	12.8%
4	CMS Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.80	10.0%	$17,400	0.45%	10.5%
5	Dominion Energy	2.1%	9.5%	11.6%	3.8%	7.8%	0.80	10.0%	$52,200	-0.26%	9.8%
6	DTE Energy Co.	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$22,900	0.45%	11.7%
7	Duke Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.85	10.4%	$78,300	-0.26%	10.2%
8	Edison International	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$25,900	0.45%	11.7%
9	Emera Inc.	2.1%	9.5%	11.6%	3.8%	7.8%	0.70	9.3%	$14,300	0.45%	9.7%
10	Entergy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$23,000	0.45%	11.7%
11	Exelon Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	n/a	n/a	$41,500	-0.26%	n/a
12	Hawaiian Elec.	2.1%	9.5%	11.6%	3.8%	7.8%	0.85	10.4%	$4,600	0.58%	11.0%
13	IDACORP, Inc.	2.1%	9.5%	11.6%	3.8%	7.8%	0.80	10.0%	$5,500	0.58%	10.6%
14	NorthWestern Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$3,400	0.93%	11.8%
15	Otter Tail Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$3,000	0.93%	11.8%
16	Pub Sv Enterprise Grp.	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$30,500	0.45%	11.3%
17	Sempra Energy	2.1%	9.5%	11.6%	3.8%	7.8%	0.95	11.2%	$49,400	-0.26%	11.0%
18	Southern Company	2.1%	9.5%	11.6%	3.8%	7.8%	0.90	10.8%	$71,300	-0.26%	10.6%
	Average (g)							**10.8%**			**11.1%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 16, 2023)..

(b) Average of weighted average earnings growth rates from IBES, Value Line, and Zacks for dividend-paying stocks in the S&P 500 based on data from Refinitiv, as provided by fidelity.com (retrieved Mar. 16, 2023), www.valueline.com (retrieved Mar. 16, 2023)., and www.zacks.com (retrieved Mar. 16, 2023). Eliminated growth rates that were greater than 20%, as well as all negative values.

(c) Average yield on 30-year Treasury bonds for six-months ending Apr. 2023 based on data from Moody's Investors Service.

(d) The Value Line Investment Survey, Summary & Index (Mar. 31, 2023).

(e) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).

(f) Kroll, 2023 Supplementary CRSP Decile Size Study Data Exhibits.

(g) Excludes highlighted values.

UTILITY GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)														
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**				**Unadjusted**	**Market**	**Size**	**ECAPM**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*** [1]	**Beta**	**Weight**	***RP*** [2]	**Total RP**	**K_e**	**Cap**	**Adjustment**	**Result**
1	Avista Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$3,200	0.93%	11.9%
2	Black Hills Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$4,600	0.58%	11.9%
3	CenterPoint Energy	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	1.10	75%	6.4%	8.4%	12.2%	$17,900	0.45%	12.6%
4	CMS Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.80	75%	4.7%	6.6%	10.4%	$17,400	0.45%	10.9%
5	Dominion Energy	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.80	75%	4.7%	6.6%	10.4%	$52,200	-0.26%	10.2%
6	DTE Energy Co.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$22,900	0.45%	11.8%
7	Duke Energy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.85	75%	5.0%	6.9%	10.7%	$78,300	-0.26%	10.5%
8	Edison International	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$25,900	0.45%	11.8%
9	Emera Inc.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.70	75%	4.1%	6.0%	9.8%	$14,300	0.45%	10.3%
10	Entergy Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$23,000	0.45%	11.8%
11	Exelon Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	n/a	75%	n/a	n/a	n/a	$41,500	-0.26%	n/a
12	Hawaiian Elec.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.85	75%	5.0%	6.9%	10.7%	$4,600	0.58%	11.3%
13	IDACORP, Inc.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.80	75%	4.7%	6.6%	10.4%	$5,500	0.58%	11.0%
14	NorthWestern Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$3,400	0.93%	11.9%
15	Otter Tail Corp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$3,000	0.93%	11.9%
16	Pub Sv Enterprise Grp.	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$30,500	0.45%	11.5%
17	Sempra Energy	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.95	75%	5.6%	7.5%	11.3%	$49,400	-0.26%	11.0%
18	Southern Company	2.1%	9.5%	11.6%	3.8%	7.8%	25%	2.0%	0.90	75%	5.3%	7.2%	11.0%	$71,300	-0.26%	10.8%
	Average (h)												**11.0%**			**11.4%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved Mar. 16, 2023)..
(b) Average of weighted average earnings growth rates from IBES, Value Line, and Zacks for dividend-paying stocks in the S&P 500 based on data from Refinitiv, as provided by fidelity.com (retrieved Mar. 16, 2023), www.valueline.com (retrieved Mar. 16, 2023)., and www.zacks.com (retrieved Mar. 16, 2023). Eliminated growth rates that were greater than 20%, as well as all negative values.
(c) Average yield on 30-year Treasury bonds for six-months ending Apr. 2023 based on data from Moody's Investors Service.
(d) Roger A. Morin, *New Regulatory Finance* , Pub. Util. Reports, Inc. (2006) at 190.
(e) The Value Line Investment Survey, Summary & Index (Mar. 31, 2023).
(f) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(g) Kroll, 2023 Supplementary CRSP Decile Size Study Data Exhibits.
(h) Excludes highlighted values.

RISK PREMIUM METHOD

COST OF EQUITY ESTIMATE

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	7.83%
(b)	Average Utility Bond Yield	5.37%
	Change in Bond Yield	-2.46%
(c)	Risk Premium/Interest Rate Relationship	-0.4273
	Adjustment to Average Risk Premium	1.05%
(a)	Average Risk Premium over Study Period	3.89%
	Adjusted Risk Premium	**4.94%**

Implied Cost of Equity		
(b)	Baa Utility Bond Yield	5.63%
	Adjusted Equity Risk Premium	4.94%
	Risk Premium Cost of Equity	**10.57%**

(a) Exhibit AMM-9, page 2.
(b) Average bond yield on all utility bonds and 'Baa' subset for six-months ending Apr. 2023 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit AMM-9, page 3.

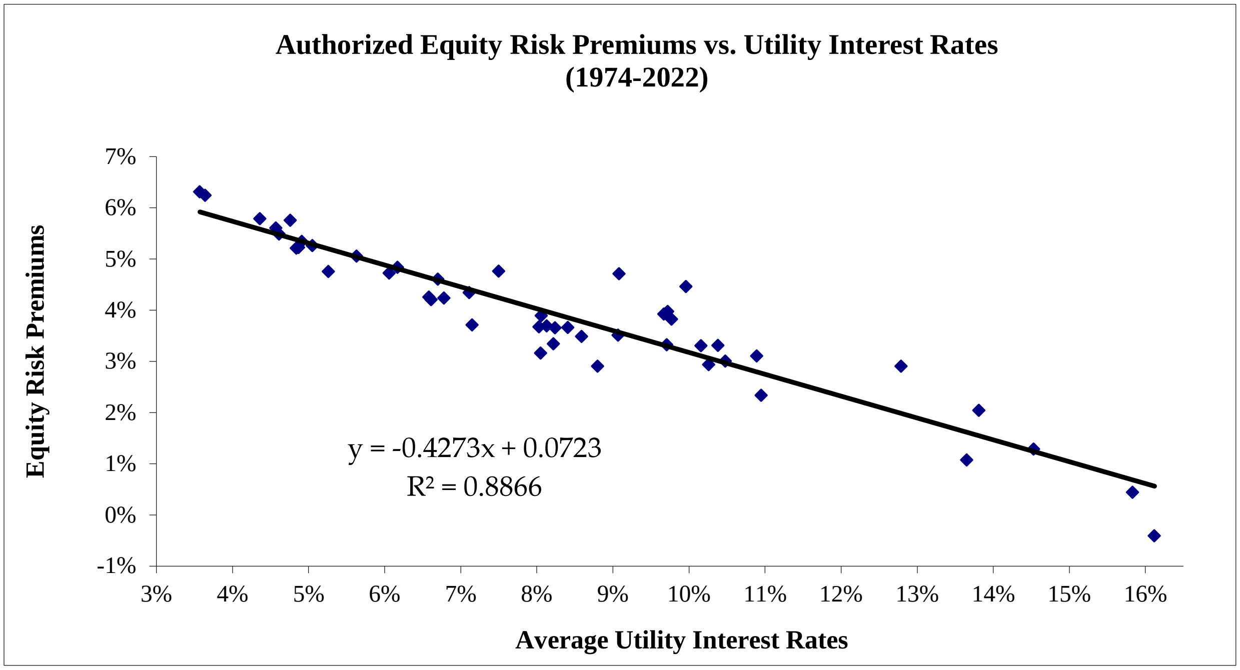
AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium	Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%	1999	10.72%	7.55%	3.17%
1975	13.20%	9.88%	3.32%	2000	11.58%	8.09%	3.49%
1976	13.10%	9.17%	3.93%	2001	11.07%	7.72%	3.35%
1977	13.30%	8.58%	4.72%	2002	11.21%	7.53%	3.68%
1978	13.20%	9.22%	3.98%	2003	10.96%	6.61%	4.35%
1979	13.50%	10.39%	3.11%	2004	10.81%	6.20%	4.61%
1980	14.23%	13.15%	1.08%	2005	10.51%	5.67%	4.84%
1981	15.22%	15.62%	-0.40%	2006	10.34%	6.08%	4.26%
1982	15.78%	15.33%	0.45%	2007	10.32%	6.11%	4.21%
1983	15.36%	13.31%	2.05%	2008	10.37%	6.65%	3.72%
1984	15.32%	14.03%	1.29%	2009	10.52%	6.28%	4.24%
1985	15.20%	12.29%	2.91%	2010	10.29%	5.56%	4.73%
1986	13.93%	9.46%	4.47%	2011	10.19%	5.13%	5.06%
1987	12.99%	9.98%	3.01%	2012	10.02%	4.26%	5.76%
1988	12.79%	10.45%	2.34%	2013	9.82%	4.55%	5.27%
1989	12.97%	9.66%	3.31%	2014	9.76%	4.41%	5.35%
1990	12.70%	9.76%	2.94%	2015	9.60%	4.37%	5.23%
1991	12.54%	9.21%	3.33%	2016	9.60%	4.11%	5.49%
1992	12.09%	8.57%	3.52%	2017	9.68%	4.07%	5.61%
1993	11.46%	7.56%	3.90%	2018	9.56%	4.34%	5.22%
1994	11.21%	8.30%	2.91%	2019	9.65%	3.86%	5.79%
1995	11.58%	7.91%	3.67%	2020	9.39%	3.07%	6.32%
1996	11.40%	7.74%	3.66%	2021	9.39%	3.14%	6.25%
1997	11.33%	7.63%	3.70%	2022	9.52%	4.76%	4.76%
1998	11.77%	7.00%	4.77%	**Average**	**11.72%**	**7.83%**	**3.89%**

(a) S&P Global Market Intelligence, *Major Rate Case Decisions* , RRA Regulatory Focus; *UtilityScope Regulatory Service* , Argus. Data for "general" rate cases (excluding limited-issue rider cases) beginning in 2006 (the first year such data presented by RRA).

(b) Moody's Investors Service.

REGRESSION RESULTS



EXPECTED EARNINGS APPROACH

UTILITY GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**
1	Avista Corp.	8.0%	1.0305	8.2%
2	Black Hills Corp.	9.5%	1.0297	9.8%
3	CenterPoint Energy	10.0%	1.0187	10.2%
4	CMS Energy Corp.	14.0%	1.0105	14.1%
5	Dominion Energy	12.0%	1.0392	12.5%
6	DTE Energy Co.	12.5%	1.0192	12.7%
7	Duke Energy Corp.	9.0%	1.0133	9.1%
8	Edison International	13.0%	1.0337	13.4%
9	Emera Inc.	10.5%	1.0105	10.6%
10	Entergy Corp.	9.0%	1.0289	9.3%
11	Exelon Corp.	10.0%	0.9820	9.8%
12	Hawaiian Elec.	12.5%	1.0209	12.8%
13	IDACORP, Inc.	9.5%	1.0238	9.7%
14	NorthWestern Corp.	8.0%	1.0277	8.2%
15	Otter Tail Corp.	11.5%	1.0195	11.7%
16	Pub Sv Enterprise Grp.	13.5%	1.0151	13.7%
17	Sempra Energy	11.0%	1.0224	11.2%
18	Southern Company	14.5%	1.0216	14.8%
	Average (d)	**11.0%**		**11.2%**

(a) The Value Line Investment Survey (Jan. 20, Feb. 10 and Mar. 10, 2023).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit AMM-6.
(c) (a) x (b).
(d) Excludes highlighted values.

FLOTATION COST STUDY

ELECTRIC & GAS UTILITIES

No.	Company	(1) Date	(2) Shares Issued	(3) Offering Price	(4) Underwriting Discount (per share)	(5) Underwriting Discount	(6) Offering Expense	(7) Total Flotation Costs	(8) Gross Proceeds Before Flot. Costs	(9) Flotation Cost (%)
1	ALLETE	4/1/2022	3,200,000	$63.00	$2.20500	$7,056,000	$700,000	$7,756,000	$201,600,000	3.847%
2	Alliant Energy	11/14/2019	3,717,502	$52.63	$0.39500	$1,468,413	$500,000	$1,968,413	$195,652,130	1.006%
3	Ameren Corp.	8/5/2019	7,549,205	$74.30	$0.12000	$905,905	$750,000	$1,655,905	$560,905,932	0.295%
4	American Elec Pwr	4/2/2009	69,000,000	$24.50	$0.73500	$50,715,000	$400,000	$51,115,000	$1,690,500,000	3.024%
5	Avangrid, Inc.					N/A				
6	Avista Corp.	12/13/2006	3,162,500	$25.05	$0.48000	$1,518,000	$300,000	$1,818,000	$79,220,625	2.295%
7	Black Hills Corp.	2/25/2020	1,222,942	$81.77	$0.73590	$899,963	$230,000	$1,129,963	$99,999,967	1.130%
8	CenterPoint Energy	9/27/2018	60,550,459	$27.25	$0.75000	$45,412,844	$1,000,000	$46,412,844	$1,650,000,008	2.813%
9	CMS Energy Corp.	3/31/2005	23,000,000	$12.25	$0.42880	$9,862,400	$325,000	$10,187,400	$281,750,000	3.616%
10	Consolidated Edison (a)	6/17/2021	10,100,000	$76.92	$0.83000	$8,383,000	$450,000	$8,833,000	$776,892,000	1.137%
11	Dominion Energy (a)	3/29/2018	20,000,000	$67.33	$1.89420	$37,884,000	$450,000	$38,334,000	$1,346,516,000	2.847%
12	DTE Energy Co.	10/29/2019	2,400,000	$126.00	$3.15000	$7,560,000	$300,000	$7,860,000	$302,400,000	2.599%
13	Duke Energy Corp. (a)	11/18/2019	25,000,000	$85.99	$2.66000	$66,500,000	$592,000	$67,092,000	$2,149,750,000	3.121%
14	Edison International	5/13/2020	14,181,882	$56.41	$0.98718	$14,000,000	$1,000,000	$15,000,000	$799,999,964	1.875%
15	Entergy Corp.	6/8/2018	13,289,037	$75.25	$0.80000	$10,631,230	$650,000	$11,281,230	$1,000,000,034	1.128%
16	Evergy Inc.					N/A				
17	Eversource Energy	6/12/2020	6,000,000	$84.91	$1.35000	$8,100,000	$600,000	$8,700,000	$509,460,000	1.708%
18	Exelon Corp. (a)	8/8/2022	11,300,000	$43.32	$0.99000	$11,187,000	$900,000	$12,087,000	$489,516,000	2.469%
19	FirstEnergy Corp.	9/15/2003	32,200,000	$30.00	$0.97500	$31,395,000	$423,000	$31,818,000	$966,000,000	3.294%
20	Hawaiian Elec.	3/20/2013	7,000,000	$26.75	$1.00312	$7,021,840	$450,000	$7,471,840	$187,250,000	3.990%
21	IDACORP, Inc.	12/10/2004	4,025,000	$30.00	$1.20000	$4,830,000	$300,000	$5,130,000	$120,750,000	4.248%
22	NextEra Energy, Inc. (a)	11/3/2016	13,800,000	$124.00	$1.89000	$26,082,000	$750,000	$26,832,000	$1,711,200,000	1.568%
23	NorthWestern Corp.	11/18/2021	6,074,767	$53.50	$1.60500	$9,750,001	$900,000	$10,650,001	$325,000,035	3.277%
24	OGE Energy Corp.	8/22/2003	5,324,074	$21.60	$0.79000	$4,206,018	$325,000	$4,531,018	$114,999,998	3.940%
25	Otter Tail Corp.					N/A				
26	Pinnacle West Capital	4/9/2010	6,900,000	$38.00	$1.33000	$9,177,000	$190,000	$9,367,000	$262,200,000	3.572%
27	PNM Resources	1/7/2020	5,375,000	$47.21	$1.99000	$10,696,250	$750,000	$11,446,250	$253,753,750	4.511%
28	Portland General Elec.	10/27/2022	10,100,000	$43.00	$1.23625	$12,486,125	$515,000	$13,001,125	$434,300,000	2.994%
29	PPL Corp.	5/10/2018	55,000,000	$27.00	$0.29430	$16,186,500	$1,000,000	$17,186,500	$1,485,000,000	1.157%
30	Pub Sv Enterprise Grp.	10/2/2003	9,487,500	$41.75	$1.25250	$11,883,094	$350,000	$12,233,094	$396,103,125	3.088%
31	Sempra Energy	1/5/2018	26,869,158	$107.00	$1.92600	$51,749,998	$1,500,000	$53,249,998	$2,874,999,906	1.852%
32	Southern Company (a)	8/18/2016	32,500,000	$49.30	$1.66000	$53,950,000	$557,000	$54,507,000	$1,602,250,000	3.402%
33	WEC Energy Group					N/A				
34	Xcel Energy Inc. (a)	10/30/2019	10,300,000	$62.69	$0.63000	$6,489,000	$650,000	$7,139,000	$645,707,000	1.106%
	Average									**2.564%**
1	Atmos Energy Corp.	11/30/2018	7,008,087	$92.75	$0.97690	$6,846,200	$1,000,000	$7,846,200	$650,000,069	1.207%
2	Chesapeake Utilities	9/23/2016	960,488	$62.26	$2.33000	$2,237,937	$162,046	$2,399,983	$59,799,983	4.013%
3	New Jersey Resources	12/4/2019	5,700,000	$41.25	$1.23750	$7,053,750	$500,000	$7,553,750	$235,125,000	3.213%
4	NiSource Inc.	5/3/2017	N/A	N/A	N/A	$10,000,000	$57,950	$10,057,950	$500,000,000	2.012%
5	Northwest Nat. Holding Co.	3/30/2022	2,500,000	$50.00	$1.62500	$4,062,500	$450,000	$4,512,500	$125,000,000	3.610%
6	ONE Gas, Inc.					N/A				
7	Southwest Gas	3/9/2023	3,576,180	$60.12	$2.02910	$7,256,427	$538,000	$7,794,427	$214,999,942	3.625%
8	Spire Inc.	5/9/2018	2,000,000	$63.05	$2.10938	$4,218,760	$325,000	$4,543,760	$126,100,000	3.603%
	Average									**3.040%**
	Average - Electric & Gas									**2.654%**

SEC Form 424B for each company (through April 10, 2023).
Column (2) * Column (4)
SEC Form 424B for each company (through April 10, 2023).
Column (5) + Column (6)
Column (2) * Column (3)
Column (7) / Column (8)
Underwriting discount computed as the difference between the current market price and the price offered to the issuing company by the underwriters.

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	3M Company	Diversified Co.	$106.36	$ 6.00	5.6%
2	Abbott Labs.	Med Supp Non-Invasive	$100.29	$ 2.04	2.0%
3	Air Products & Chem.	Chemical (Diversified)	$281.14	$ 7.00	2.5%
4	Allstate Corp.	Insurance (Prop/Cas.)	$120.44	$ 3.56	3.0%
5	Amdocs Ltd.	IT Services	$92.79	$ 1.74	1.9%
6	Amgen	Biotechnology	$234.21	$ 8.52	3.6%
7	Archer Daniels Midl'd	Food Processing	$79.03	$ 1.80	2.3%
8	Becton, Dickinson	Med Supp Invasive	$237.50	$ 3.68	1.5%
9	Bristol-Myers Squibb	Drug	$68.51	$ 2.31	3.4%
10	Brown & Brown	Financial Svcs. (Div.)	$55.82	$ 0.46	0.8%
11	Brown-Forman 'B'	Beverage	$63.90	$ 0.82	1.3%
12	Church & Dwight	Household Products	$84.48	$ 1.09	1.3%
13	Cisco Systems	Telecom. Equipment	$49.51	$ 1.56	3.2%
14	Coca-Cola	Beverage	$60.07	$ 1.84	3.1%
15	Colgate-Palmolive	Household Products	$72.99	$ 1.92	2.6%
16	Comcast Corp.	Cable TV	$36.81	$ 1.16	3.2%
17	Costco Wholesale	Retail Store	$488.50	$ 3.75	0.8%
18	Danaher Corp.	Diversified Co.	$247.94	$ 1.08	0.4%
19	Gen'l Mills	Food Processing	$80.16	$ 2.17	2.7%
20	Gilead Sciences	Drug	$80.65	$ 3.00	3.7%
21	Hershey Co.	Food Processing	$241.73	$ 4.27	1.8%
22	Home Depot	Retail Building Supply	$292.87	$ 8.36	2.9%
23	Hormel Foods	Food Processing	$41.24	$ 1.10	2.7%
24	Intercontinental Exch.	Brokers & Exchanges	$100.99	$ 1.68	1.7%
25	Johnson & Johnson	Med Supp Non-Invasive	$154.32	$ 4.52	2.9%
26	Kimberly-Clark	Household Products	$126.71	$ 4.72	3.7%
27	Lilly (Eli)	Drug	$325.23	$ 4.52	1.4%
28	Lockheed Martin	Aerospace/Defense	$475.63	$ 12.20	2.6%
29	Marsh & McLennan	Financial Svcs. (Div.)	$161.25	$ 2.48	1.5%
30	McCormick & Co.	Food Processing	$73.91	$ 1.56	2.1%
31	McDonald's Corp.	Restaurant	$267.83	$ 6.20	2.3%
32	McKesson Corp.	Med Supp Non-Invasive	$348.20	$ 2.28	0.7%
33	Merck & Co.	Drug	$107.28	$ 2.92	2.7%
34	Microsoft Corp.	Computer Software	$262.00	$ 2.73	1.0%
35	Mondelez Int'l	Food Processing	$66.46	$ 1.54	2.3%
36	NewMarket Corp.	Chemical (Specialty)	$347.55	$ 8.40	2.4%
37	Northrop Grumman	Aerospace/Defense	$461.03	$ 6.92	1.5%
38	Oracle Corp.	Computer Software	$87.33	$ 1.60	1.8%
39	PepsiCo, Inc.	Beverage	$175.49	$ 4.60	2.6%
40	Pfizer, Inc.	Drug	$40.85	$ 1.64	4.0%
41	Procter & Gamble	Household Products	$140.96	$ 3.65	2.6%
42	Progressive Corp.	Insurance (Prop/Cas.)	$141.53	$ 0.40	0.3%
43	Republic Services	Environmental	$129.80	$ 1.98	1.5%
44	Sherwin-Williams	Retail Building Supply	$219.55	$ 2.42	1.1%
45	Smucker (J.M.)	Food Processing	$150.87	$ 4.14	2.7%
46	Texas Instruments	Semiconductor	$174.94	$ 4.96	2.8%
47	Thermo Fisher Sci.	Precision Instrument	$551.89	$ 1.40	0.3%
48	Travelers Cos.	Insurance (Prop/Cas.)	$176.47	$ 3.72	2.1%
49	Verizon Communic.	Telecom. Services	$38.05	$ 2.64	6.9%
50	Walmart Inc.	Retail Store	$141.28	$ 2.32	1.6%
51	Waste Management	Environmental	$152.25	$ 2.80	1.8%
	Average				**2.3%**

(a) Average of closing prices for 30 trading days ended Mar. 29, 2023.
(b) The Value Line Investment Survey, *Summary & Index* (Mar. 31, 2023).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth		
	Company	**V Line**	**IBES**	**Zacks**
1	3M Company	7.50%	0.09%	9.50%
2	Abbott Labs.	6.50%	8.30%	5.09%
3	Air Products & Chem.	11.50%	8.79%	11.68%
4	Allstate Corp.	3.50%	-2.19%	7.00%
5	Amdocs Ltd.	7.50%	11.07%	11.00%
6	Amgen	4.50%	4.12%	7.00%
7	Archer Daniels Midl'd	13.00%	-2.80%	6.39%
8	Becton, Dickinson	5.00%	6.30%	7.77%
9	Bristol-Myers Squibb	n/a	4.06%	5.70%
10	Brown & Brown	8.00%	13.22%	n/a
11	Brown-Forman 'B'	14.50%	8.85%	n/a
12	Church & Dwight	6.00%	7.81%	7.64%
13	Cisco Systems	8.50%	7.32%	6.50%
14	Coca-Cola	8.00%	6.06%	6.66%
15	Colgate-Palmolive	6.00%	6.02%	6.21%
16	Comcast Corp.	8.50%	6.40%	12.64%
17	Costco Wholesale	10.50%	9.90%	9.24%
18	Danaher Corp.	16.00%	3.31%	12.00%
19	Gen'l Mills	4.50%	7.04%	7.50%
20	Gilead Sciences	12.00%	2.52%	12.26%
21	Hershey Co.	9.00%	9.64%	7.67%
22	Home Depot	9.00%	2.22%	11.22%
23	Hormel Foods	7.50%	3.30%	5.83%
24	Intercontinental Exch.	7.00%	5.86%	5.40%
25	Johnson & Johnson	8.00%	3.94%	5.53%
26	Kimberly-Clark	7.00%	9.61%	9.86%
27	Lilly (Eli)	11.50%	22.87%	20.62%
28	Lockheed Martin	7.00%	9.55%	6.86%
29	Marsh & McLennan	10.50%	9.08%	8.46%
30	McCormick & Co.	4.50%	3.51%	6.92%
31	McDonald's Corp.	9.00%	7.75%	8.07%
32	McKesson Corp.	10.00%	11.87%	10.36%
33	Merck & Co.	8.50%	10.47%	8.01%
34	Microsoft Corp.	15.00%	11.90%	11.66%
35	Mondelez Int'l	7.50%	6.45%	7.14%
36	NewMarket Corp.	1.00%	7.70%	n/a
37	Northrop Grumman	9.50%	3.00%	3.45%
38	Oracle Corp.	10.00%	9.06%	8.00%
39	PepsiCo, Inc.	6.50%	7.55%	7.63%
40	Pfizer, Inc.	2.00%	-8.00%	9.00%
41	Procter & Gamble	5.50%	5.07%	6.14%
42	Progressive Corp.	6.50%	28.64%	23.89%
43	Republic Services	12.50%	8.97%	9.11%
44	Sherwin-Williams	7.00%	9.07%	10.30%
45	Smucker (J.M.)	4.00%	3.79%	4.00%
46	Texas Instruments	4.50%	10.00%	9.33%
47	Thermo Fisher Sci.	11.00%	7.77%	12.50%
48	Travelers Cos.	7.50%	8.83%	10.71%
49	Verizon Communic.	2.50%	0.13%	4.15%
50	Walmart Inc.	7.50%	5.09%	5.50%
51	Waste Management	6.50%	8.75%	10.88%

(a) The Value Line Investment Survey (various editions as of Mar. 31, 2023).
(b) www.finance.yahoo.com (retrieved Mar. 30, 2023).
(c) www.zacks.com (retrieved Mar. 30, 2023).

DCF MODEL - NON-UTILITY GROUP

DCF COST OF EQUITY ESTIMATES

	Company	(a) V Line	(b) IBES	(c) Zacks
1	3M Company	13.1%	5.7%	15.1%
2	Abbott Labs.	8.5%	10.3%	7.1%
3	Air Products & Chem.	14.0%	11.3%	14.2%
4	Allstate Corp.	6.5%	0.8%	10.0%
5	Amdocs Ltd.	9.4%	12.9%	12.9%
6	Amgen	8.1%	7.8%	10.6%
7	Archer Daniels Midl'd	15.3%	-0.5%	8.7%
8	Becton, Dickinson	6.5%	7.8%	9.3%
9	Bristol-Myers Squibb	n/a	7.4%	9.1%
10	Brown & Brown	8.8%	14.0%	n/a
11	Brown-Forman 'B'	15.8%	10.1%	n/a
12	Church & Dwight	7.3%	9.1%	8.9%
13	Cisco Systems	11.7%	10.5%	9.7%
14	Coca-Cola	11.1%	9.1%	9.7%
15	Colgate-Palmolive	8.6%	8.7%	8.8%
16	Comcast Corp.	11.7%	9.6%	15.8%
17	Costco Wholesale	11.3%	10.7%	10.0%
18	Danaher Corp.	16.4%	3.7%	12.4%
19	Gen'l Mills	7.2%	9.7%	10.2%
20	Gilead Sciences	15.7%	6.2%	16.0%
21	Hershey Co.	10.8%	11.4%	9.4%
22	Home Depot	11.9%	5.1%	14.1%
23	Hormel Foods	10.2%	6.0%	8.5%
24	Intercontinental Exch.	8.7%	7.5%	7.1%
25	Johnson & Johnson	10.9%	6.9%	8.5%
26	Kimberly-Clark	10.7%	13.3%	13.6%
27	Lilly (Eli)	12.9%	24.3%	22.0%
28	Lockheed Martin	9.6%	12.1%	9.4%
29	Marsh & McLennan	12.0%	10.6%	10.0%
30	McCormick & Co.	6.6%	5.6%	9.0%
31	McDonald's Corp.	11.3%	10.1%	10.4%
32	McKesson Corp.	10.7%	12.5%	11.0%
33	Merck & Co.	11.2%	13.2%	10.7%
34	Microsoft Corp.	16.0%	12.9%	12.7%
35	Mondelez Int'l	9.8%	8.8%	9.5%
36	NewMarket Corp.	3.4%	10.1%	n/a
37	Northrop Grumman	11.0%	4.5%	5.0%
38	Oracle Corp.	11.8%	10.9%	9.8%
39	PepsiCo, Inc.	9.1%	10.2%	10.3%
40	Pfizer, Inc.	6.0%	-4.0%	13.0%
41	Procter & Gamble	8.1%	7.7%	8.7%
42	Progressive Corp.	6.8%	28.9%	24.2%
43	Republic Services	14.0%	10.5%	10.6%
44	Sherwin-Williams	8.1%	10.2%	11.4%
45	Smucker (J.M.)	6.7%	6.5%	6.7%
46	Texas Instruments	7.3%	12.8%	12.2%
47	Thermo Fisher Sci.	11.3%	8.0%	12.8%
48	Travelers Cos.	9.6%	10.9%	12.8%
49	Verizon Communic.	9.4%	7.1%	11.1%
50	Walmart Inc.	9.1%	6.7%	7.1%
51	Waste Management	8.3%	10.6%	12.7%
	Average (b)	**10.9%**	**10.4%**	**10.9%**

(a) Sum of dividend yield (p. 1) and respective growth rate (p. 2).
(b) Excludes highlighted figures.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

FRANZ D. MESSNER

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
FRANZ D. MESSNER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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DIRECT TESTIMONY OF
FRANZ D. MESSNER ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Franz D. Messner. I am employed by American Electric Power Service Corporation ("AEPSC") as Managing Director of Corporate Finance. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power ("AEP") system, one of which is Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio, 43215.

II. BACKGROUND

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I earned a Bachelor of Science in Systems Engineering from the United States Naval Academy in 1990. I earned a Master of Business Administration from the Fisher College of Business at the Ohio State University in 1999. Prior to joining AEP, I served for approximately seven years as a U.S. Naval officer and completed both chief engineer and submarine officer qualifications.

In June 1999, I was hired by AEPSC as an associate in a finance associate development program. My primary roles have been in the areas of financial analysis, budgeting, and forecasting. In July 2007, I was named Manager in Corporate Planning and Budgeting and subsequently promoted to Director in November 2009. In May 2016, I assumed my current position as Managing Director of Corporate Finance.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF CORPORATE FINANCE?

A. I am responsible for planning and executing the corporate finance programs of the regulated AEP System operating companies, including Kentucky Power. My responsibilities also include preparing recommendations for the payment of dividends by those companies, maintaining capitalization targets, and managing the relationships of AEP and its subsidiaries with the credit rating agencies.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes, I have submitted testimony on behalf of Indiana Michigan Power before the Indiana Utility Regulatory Commission and the Michigan Public Service Commission, Ohio Power before the Public Utilities Commission of Ohio, Kentucky Power before the Public Service Commission of Kentucky (the "Commission"), Appalachian Power before the Virginia State Corporation Commission and Kingsport Power before the Tennessee Public Utility Commission. Additionally, I have prepared or had prepared under my direct supervision financing applications submitted on behalf of Kentucky Power Company to the Public Service Commission of Kentucky.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY ON THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present and support Kentucky Power's capital structure and weighted average cost of capital ("WACC"). Pursuant to KRS 278.672(2)(f)'s requirements, I also present "[a] comparison between the net present value of the costs to ratepayers that are estimated to result from the issuance of securitized bonds" (Securitization Method) and "the cost that would result from an alternative means of providing for the full recovery of and return on those securitized costs from customers, using [Kentucky Power's] . . . expected [(proposed)] weighted average cost of capital" (Conventional Method) to "demonstrate that the issuance of securitized bonds and the imposition of securitized surcharges are expected to provide quantifiable net present value benefits to customers."

Q. ARE YOU SPONSORING ANY SCHEDULES OR WORKPAPERS?

A. Yes. I am sponsoring the following Section V Workpapers:

- Section V Workpaper S-2 Page 1 – Cost of Capital
- Section V Schedule 3 (Column 3, Lines 1-3) – Capitalization
- Section V Workpaper S-3 Page 1 – Long-Term Debt
- Section V Workpaper S-3 Page 2 – Schedule of Short-Term Debt

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

EXHIBIT	DESCRIPTION
Exhibit FDM-1	Net Present Value Comparison of Securitization Method vs Conventional Method
Exhibit FDM-2	Estimated Upfront and Ongoing Costs of Securitization

IV. PROPOSED COST OF CAPITAL AND CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE KENTUCKY POWER'S PROPOSED CAPITAL STRUCTURE AND WEIGHTED AVERAGE COST OF CAPITAL.

A. Based on the test year ended March 31, 2023, Kentucky Power's proposed capital structure and weighted average cost of capital of 6.93% are set forth in Figure FDM-1 below:

Figure FDM-1

Line No. (1)	Description (2)	Reapportioned Kentucky Jurisdictional Capital 1/ (3)	Percentage of Total (4)	Annual Cost Percentage Rate (5)		Weighted Average Cost Percent (6) = (4) X (5)
1	Long Term Debt	$962,401,699	53.10%	4.910%	2/	2.61%
2	Short Term Debt	$95,743,648	5.28%	3.730%	3/	0.20%
3	Common Equity	$754,394,228	41.62%	**9.90%**	4/	4.12%
4	Total	$1,812,539,575	100.00%			**6.93%**

Q. HOW WAS THE COMPANY'S PROPOSED CAPITAL STRUCTURE DEVELOPED?

A. Development of the proposed capital structure, as shown in Figure FDM 1, begins with the per books balance for each category of capital as of the end of the test year, March 31, 2023. The per books balances are then adjusted to account for known and measurable changes to the Company's capitalization. The capitalization adjustments are shown in Section V, Schedule 3 and detailed in the testimonies of Company Witnesses Kahn, Schlessman, and Whitney.

Q. COMPARE THE DEBT AND EQUITY COMPONENTS IN THE COMPANY'S PROPOSED CAPITAL STRUCTURE TO THE CAPITAL STRUCTURE PROPOSED IN THE COMPANY'S LAST BASE RATE CASE (CASE NO. 2020-00174).

A. The Company's proposed capital structure in this base rate case has a higher level of debt and lower level of equity as compared to the Company's last base rate case (Case No. 2020-00174). The Company's Per Book Balance of debt as of March 31, 2023, as shown in Section V, Schedule 3, Column (3) was 58.3% as compared to 41.7% equity. The Reapportioned Kentucky Jurisdictional Capital shown Table 1 above and in Section V, Schedule 2, Page 1 columns (3) and (4) was 58.4% debt and 41.6% equity.

In the Company's last base rate case (Case No. 2020-00174) the Company's Per Book Balance of debt as of March 31, 2020, was 56.7% as compared to 43.3% equity. The Reapportioned Kentucky Jurisdictional Capital was also 56.7% debt and 43.3% equity.

Q. IS ANY OF THE DECREASE IN EQUITY RELATIVE TO DEBT DUE TO PAYMENT OF DIVIDENDS FROM KENTUCKY POWER TO ITS PARENT?

A. No, Kentucky Power made no dividend payments since the last base rate case in 2020.

Q. WHAT IMPACT DOES HAVING A CAPITAL STRUCTURE WITH A LOWER LEVEL OF EQUITY RELATIVE TO DEBT HAVE ON A COMPANY'S CREDIT RATINGS?

A. A capital structure with a lower level of equity relative to debt is viewed negatively by credit rating agencies due to the negative impact on a company's ability to repay its debt and other obligations in full and on time. Credit ratings and the impact on a company's access to capital markets financing are discussed in detail by Company Witness Fetter.

Q. PLEASE EXPLAIN HOW THE PROPOSED WEIGHTED AVERAGE COST OF CAPITAL OF 6.93% WAS CALCULATED.

A. The proposed weighted average cost of capital is based on the summation of the weighted average cost for each source of capital in the Company's capital structure, including long-term debt, short-term debt, and common stock. The calculation is shown on Section V, Schedule 2, page 1. The Company began with the Reapportioned Kentucky Jurisdictional capitalization as calculated on Section V, Schedule 3, column 15 for each source of capital. Next, the Company divided the dollar amount of each component of capital by the Company's total dollar amount of capital to derive the percentage of the Company's total capital each component represents. The percentage of total capital was then multiplied by the respective annual cost percentage rate for each source of capital.

Q. PLEASE EXPLAIN WHAT RATES WERE USED IN CALCULATING THE COMPANY'S PER BOOKS WEIGHTED AVERAGE COST OF CAPITAL AS OF MARCH 31, 2023.

A. The weighted cost of long-term debt was determined by taking the sum of each debt instrument's actual annualized cost and dividing that amount by the total debt outstanding as of March 31, 2023. The annualized cost for each debt instrument was calculated by multiplying the effective cost rate (yield to maturity) by the net proceeds outstanding. Please refer to Section V, Workpaper S-3, page 1.

The cost of short-term debt used in the calculation is the Company's actual short-term interest expense for the twelve months ended March 31, 2023, divided by the actual average borrowings outstanding during the same time-period. Please refer to Section V, Workpaper S-3, page 2. As mentioned earlier, the per books balances are adjusted to account for known and measurable changes to the Company's capitalization as shown in Section V, Schedule 3 and detailed in the testimonies of Company Witnesses Kahn, Schlessman, and Whitney. Though the per books short-term debt balance on March 31, 2023, was approximately $113.6 million, the adjusted balance included in the weighted average cost of capital calculation was approximately $95.7 million due to the Mitchell Coal Stock Adjustment shown in Section V, Schedule 3, column 14 and sponsored by Company Witness Whitney.

The 9.90% cost of common equity used in the calculation is based on direction from Company Witness Wiseman.

V. CALCULATION OF STATUTORY SECURITIZATION NET PRESENT VALUE ANALYSIS

Q. DOES THE PROPOSED ISSUANCE OF SECURITIZED BONDS SATISFY THE NET PRESENT VALUE TEST SET FORTH IN THE SECURITIZATION STATUTE?

A. Yes. Following the methodology prescribed in KRS 278.672(2)(f), the issuance of securitized bonds and the imposition of securitized surcharges are expected to provide a quantifiable net present value ("NPV") benefit to customers. Based on current market conditions, the statutory calculation results in an estimated positive NPV (Securitization Method minus Conventional Method) of approximately $74 million.

Again, this amount is an estimate based on current market conditions and reasonable assumptions regarding tenor, coupon upfront, and ongoing bond costs and may change between now and the date of the securitized bonds' issuance.

Q. HOW WAS THE NET PRESENT VALUE OF THE COST ASSOCIATED WITH THE CONVENTIONAL METHOD CALCULATED?

A. As described by Company Witness West, the Company is proposing to securitize various regulatory assets with a cumulative total value of approximately $471.2 million. In calculating the NPV of the cost that would result from an alternative means of providing for the full recovery of and return on those regulatory assets from customers using the Company's proposed weighted average cost of capital (the Conventional Method), the asset balance was divided into two parts to calculate the NPV of costs based on the period over which these assets are typically recovered. Specifically, the Decommissioning Rider Regulatory Asset calculation assumes recovery over seventeen years, while recovery of the remainder of the regulatory assets assumes a five-year recovery period. In addition, the Decommissioning Rider Regulatory Asset and the Rockport Deferral Regulatory Asset balances have been reduced by the NPV of the return on accumulated deferred income taxes ("ADIT") provided by Company Witness Walsh. These amounts were then discounted at the Company's proposed WACC to determine the NPV of costs, consistent with the methodology provided for in the securitization statute.

Q. HOW WAS THE NET PRESENT VALUE OF THE COST ASSOCIATED WITH THE SECURITIZATION METHOD CALCULATED?

A. The NPV of the cost of recovering the regulatory assets through securitization was calculated using estimates of the amount, tenor and coupon associated with the securitized bonds. The amount includes the approximately $471.2 million of regulatory assets described in Company Witness West's Direct Testimony, reduced by the NPV of the return on the ADIT as provided by Company Witness Walsh, plus upfront costs associated with issuing securitized bonds, as summarized in Figure FDM-2:

Figure FDM-2

Estimated Bond Issuance		
Total Regulatory Asset Balance	$	471,198,800
Reduce NPV of Return on ADIT	$	30,809,003
Securitization Amount	$	440,389,797
Upfront Costs	$	6,310,203
Estimated Bond Issuance	$	446,700,000

The indicative coupon and tenor were provided to me by Goldman Sachs, the Company's securitization financial advisor, based on prevailing market conditions. Company Witness Schlessman provided the value of the ADIT used in the NPV calculation and Company Witness Walsh provided the NPV of the return on ADIT owed to customers. The calculation assumes a mortgage-like series of payments that are constant over the 20-year bond life while the relative amounts of principal and interest change over the same period. These amounts were then discounted at the Company's proposed WACC to determine the NPV of costs.

Q. PLEASE EXPLAIN THE UPFRONT AND ONGOING COSTS ASSOCIATED WITH SECURITIZATION.

A. As shown on Exhibit FDM-1, I have estimated the upfront and ongoing costs associated with securitization. These costs are necessary to cover the expenses incurred during the securitized bonds' issuance. The fees include Securities and Exchange Commission fees, legal and accounting fees, rating agency fees, Commission and Company advisor fees, as well as printing fees. In addition, the Company will incur ongoing auditing, accounting, and other administrative costs throughout the term of the bonds and will receive a return on the capital account it establishes for the securitization special purpose entity at the proposed WACC.[1] These fees are estimated based on experience from other AEP operating companies' prior securitized bond issuances. The Company will update these estimates to the actual values, if known, prior to issuing the bonds.

Q. DOES THE COMPANY ANTICIPATE INCURRING COSTS OF RETIRING OR REFUNDING DEBT OR EQUITY IN CONNECTION WITH THE USE OF THE PROCEEDS FROM THE ISSUANCE OF THE SECURITIZED BONDS?

A. No.

Q. WHAT IS THE PROPOSED SECURITIZED BOND RECOVERY PERIOD THE COMPANY HAS PRESENTED IN THIS CASE?

A. The proposed securitized bond recovery period is 20 years.

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[1] KRS 278.676(1)(m).

Q. WHAT IS THE ESTIMATED REVENUE REQUIREMENT FOR SECURITIZATION TO BE COLLECTED FROM CUSTOMERS?

A. The estimated revenue requirement is approximately $37 million on an annual basis. This revenue requirement includes the semi-annual bond payments as well as the ongoing costs associated with securitization.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Franz D. Messner, being duly sworn, deposes and says he is Managing Director, Corporate Finance that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

____
Franz D. Messner

State of Ohio)
) Case No. 2023-00159
County of Franklin)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Franz D. Messner, on 6/27/23.

____
Notary Public

My Commission Expires Never

Notary ID Number None

NOTARIAL SEAL STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

Conventional Recovery	Regulatory Asset (Net of Return on ADIT)	Estimated Upfront Costs	Annual Charge	NPV	Disc. Rate
Decommissioning Rider 17 Years @ WACC	$ 256,091,825	-	$ 27,962,969	$ 254,332,690	8.300%
All Other 5 Years @ WACC	$ 180,058,355	-	$ 43,819,010	$ 178,821,506	8.300%
	$ 436,150,180		$ 71,781,979	$ 433,154,197	
Securitization					
Securitization 20 Year Semi-Annual	$ 440,389,797	6,310,203	$ 37,061,497	$ 358,728,229	8.300%
Estimated Savings NPV				**$ 74,425,968**	

Description of Cost items		Upfront Costs	
Based on averages of recent deals for fixed costs			
Legal Fees/Exp for Company's/Issuer's Counsel	$	2,750,000	
Fee for Commission & Company's Financial Advisor	$	750,000	
Printing/Edgarizing Expenses	$	75,000	
Miscellaneous Administrative Costs	$	31,242	
Rating Agency Fees	$	591,965	
Accountant's Fees	$	150,000	
Servicer Set-up Costs	$	125,000	
Trustee's/Trustee's Counsel Fees and Expenses	$	25,000	**Rate**
Underwriting Fee	$	1,787,066	0.400%
SEC Fees	$	24,930	0.006%
Total Fixed Qualified Costs	**$**	**6,310,203**	
Costs as % of Bonds		1.4%	
		Ongoing Costs	
Ongoing Servicer Fee (AEP as Servicer)	$	446,766	0.10%
Administration Fee	$	100,000	
Accountants' Fees	$	75,000	
Legal Fees/Expenses for Company's/Issuer's Counsel	$	50,000	
Trustee's/Trustee's Counsel Fees and Expenses	$	10,000	
Independent Managers' Fee	$	2,750	
Rating Agency Fees	$	75,000	
Return on Capital Account	$	188,027	
Miscellaneous	$	25,000	
Total Annual Ongoing Costs	**$**	**972,543**	

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF
KATRINA T. NIEHAUS. FOR
KENTUCKY POWER COMPANY

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KATRINA T. NIEHAUS

FOR
KENTUCKY POWER COMPANY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Katrina T. Niehaus, and my business address is 200 West Street, New York, New York 10282.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Managing Director, Co-Head of the Corporate Asset Backed Securities ("ABS") Finance Group at Goldman Sachs & Co. ("Goldman").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Economics degree from the Wharton School at the University of Pennsylvania. Prior to joining Goldman in 2005, I was employed by Lehman Brothers. I was at Lehman Brothers from 2004-2005 as an analyst. During my time at Goldman, I have assisted a number of utilities and states through the securitization process as an advisor or underwriter including Pacific Gas & Electric, Entergy Texas, Entergy Louisiana, Jersey Central Power & Light, AEP Texas Central Power Company, and the State of Hawaii. Currently, I oversee a group that has responsibility for the origination and structuring of securitizations backed by a broad range of assets including nonbypassable ratepayer charges, solar loans and leases, triple net leases, intellectual property, and small business loans.

Q. DO YOU POSSESS ANY PROFESSIONAL LICENSES RELATED TO THE SECURITIES INDUSTRY?

A. Yes. I am Series 7 (General Securities Representative Qualification) qualified by the Financial Industry Regulatory Authority, which allows an individual to solicit, purchase, or sell all securities products, including asset-backed securities. I am also Series 79 (Investment Banking Representative) qualified, which allows an individual to advise on and facilitate debt and equity offerings (public offerings or private placements), mergers and acquisitions, tender offers, financial restructurings, asset sales, divestitures, corporate reorganizations and business combination transactions. A copy of my professional resume is attached as Niehaus Exhibit 4.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Kentucky Power Company ("Kentucky Power" or the "Company").

Q. HAVE YOU PREVIOUSLY TESTIFIED IN A REGULATORY PROCEEDING?

A. Yes. I have provided testimony before the public service commissions of the states of California, Louisiana, New Hampshire and Texas, as further indicated in my resume attached hereto as Exhibit 4.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to:

1. Provide background information on the use of utility securitizations in other jurisdictions as well as discuss some of the basic elements of the proposed securitized bonds. "Utility securitization" is a generic term used to refer to securitizations for several different recovery purposes. Some of the other names used to refer to this structure include rate reduction bonds, stranded cost bonds, storm recovery bonds, system restoration bonds, and restructuring bonds.
2. Present a proposed preliminary securitized bond issuance structure for use in Kentucky and discuss certain structuring and marketing considerations.
3. Discuss the primary rating agency criteria for utility securitizations to obtain the desired triple-A ratings.
4. Discuss several of the key commercial terms of proposed securitized bonds that Kentucky Power expects will be required for a successful transaction, as well as key provisions of the proposed financing order.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following exhibits described below and attached to my testimony:

- Niehaus Exhibit 1: Internal Revenue Service Revenue Procedure 2005-62
- Niehaus Exhibit 2: Preliminary Transaction Structure

- Niehaus Exhibit 3: Utility Securitization Transactions, 1997-Present
- Niehaus Exhibit 4: Professional Resume of Katrina T. Niehaus

Each of these exhibits were prepared under my direction and control, and to the best of my knowledge all factual matters contained therein are true and accurate.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. Pursuant to KRS 278.670, *et seq*., (the "Securitization Statute"), Kentucky Power is submitting an Application for Financing Order (the "Application"), which requests approval of a financing order authorizing the issuance of securitized bonds to finance though securitization (1) the balance of (a) extraordinary storm costs and other deferred costs from previous events for regulatory assets with an expected cumulative balance as of June 30, 2023 of approximately $471 million plus (b) carrying costs accruing on the applicable portions of such balance at the weighted average cost of capital approved in this case through the date the securitized bonds are issued minus (c) all insurance, scrap, and salvage proceeds, applicable unamortized regulatory liabilities for excess deferred income taxes; and the present value of return on all accumulated deferred income taxes related to pretax costs with respect to a retired or abandoned facility and related facilities, including those due to bonus and accelerated tax depreciation and abandonment losses; and (2) certain up-front financing costs, among other items. Accordingly, my testimony provides background about, and makes recommendations for, the financing order proposed by the Company.

In this testimony I recommend the following:

- The adoption of an irrevocable financing order that creates securitized property for the benefit of the Company, consisting of nonbypassable securitized surcharge included on the bills of the Company's customers, which surcharge is subject to automatic adjustment by the application of a formula-based true-up mechanism, or "true-up" process, in order to ensure collections from such surcharges are sufficient to pay debt service on securitized bonds.
- The authorization in such financing order of the sale of the securitized property to the bankruptcy-remote (meaning that the bankruptcy of the Company will not impact the issuer or the credit quality of the bonds), special purpose issuer organized by the Company in a "true-sale" in exchange for such issuer's net proceeds on the securitized bonds it issues to finance the purchase of the securitized property. These transaction elements will help ensure that the bankruptcy of the Company will not impact the issuer or the credit quality of the securitized bonds.
- The marketing and sale of the securitized bonds through a public, Securities and Exchange Commission ("SEC") registered transaction to achieve the greatest level of liquidity and the broadest investor universe for the securitized bonds.
- The need for the financing order to afford the Company the flexibility to establish the final terms and conditions of the securitized bonds in order to ensure the transaction can be executed on a basis that allows the securitized bonds to receive the highest possible credit ratings.

Specifically, my testimony describes how a securitization meeting the requirements outlined above is expected to provide quantifiable net present value benefits to the customers of Kentucky Power as compared to recovery of the costs that would have been incurred absent the issuance of securitized bonds, and how the recommended structure and the market-clearing and pricing process are reasonably expected to result in the lowest securitized surcharges, consistent with market conditions at the time the securitized bonds are priced under the terms of the financing order.

Q. PLEASE ELABORATE FURTHER ON THE GOAL OF UTILITY SECURITIZATIONS AND HOW YOUR RECOMMENDATIONS HELP TO ACHIEVE THIS GOAL.

A. Before I discuss the securitization process in detail, I review here (1) the principal goal of utility securitizations, (2) how these securitizations differ from utility corporate debt and other structured debt, and (3) why the issuance of the financing order, consistent with the letter and spirit of the Securitization Statute, is critical to achieve the goal of utility securitizations – to deliver savings to customers.

Significant customer savings. As reflected in Niehaus Exhibit 3, over $81 billion of rate reduction bonds have been issued successfully by or on behalf of utilities since the mid-1990s to recover authorized costs in a manner designed to produce significant customer savings.

With the appropriate statutory framework and a carefully crafted financing order, securitizations benefit from a significantly lower cost of capital compared to traditional investor-owned utility rate mechanisms. Typically, traditional rate mechanisms set customer rates based upon a utility's weighted cost of capital, which includes an average corporate debt cost along with a generally higher allowed return on 50 percent or more equity capital in the calculation. Utility securitization customer charges are based upon a capital cost comprised of 99.5 percent AAA-rated debt and 0.5 percent equity. By significantly increasing the percentage of debt and virtually eliminating the equity return component of these transactions, utility ratepayers can save millions of dollars in carrying costs associated with the recovery of these legitimate utility expenses.

Distinct from utility unsecured and first mortgage debt. Utility securitizations are quite different from traditional utility debt offerings. Unsecured utility corporate debt offerings are full recourse obligations of the utility. First mortgage debt offerings are also full recourse to the utility with the added security of a first lien on tangible utility property. In contrast, utility securitizations are non-recourse to the corporate credit of the utility. Lack of recourse to the utility means that the utility securitizations can achieve credit ratings above that of the utility itself, and indeed are designed to achieve the highest possible bond ratings: AAA.

The Public Service Commission of Kentucky's ("Commission") Financing Orders are critical. For an investor-owned utility to recover authorized costs in a manner that results in significant customer savings through securitization, the proper statutory framework is required, coupled with a

Commission-issued financing order that is consistent with the letter and the spirit of the authorizing statute. I believe the Securitization Statute has the proper framework authorizing these securitizations and outlines the necessary statutory requirements for securitization financing orders. I also believe that Kentucky Power, through the Application and accompanying testimony, has proposed a financing order that meets the requirements for the securitized bonds to achieve AAA ratings.

Utility securitizations not only aim to achieve the lowest charges for customers by issuing debt with the highest possible rating (resulting in the lowest comparative price), but do so by structuring the transactions without what is called "overcollateralization." Like utility securitizations, other types of securitization debt are also non-recourse to the sponsor of the transaction and the securitization issuer is bankruptcy-remote to the sponsor. A key factor in determining the ratings for most other securitizations is "overcollateralization," meaning an incremental amount of collateral that is pledged to the bondholders to provide extra security if the pledged assets do not perform as expected. The excess cash flow from the additional collateral increases what is called the "debt service coverage," or the amount of cash available to pay principal and interest on the bonds. For each type of securitization, rating agencies will run stress scenarios to determine how much overcollateralization and debt service coverage is required to achieve a particular rating. However, in a typical utility securitization structure, the rating agencies do not require any extra collateral to be held in the special purpose entity ("SPE") formed to issue the bonds in order to achieve the highest possible rating (AAA or equivalent), because the structure instead includes a mandatory true-up mechanism that adjusts customer charges over time to pay debt service and ongoing financing costs on a timely basis. This combination of AAA (or equivalent) ratings and the lack of any excess collateral and therefore excess debt service coverage is unique to this type of securitization structure. Rarely is overcollateralization required in utility securitizations, meaning no cushion on the amount of customer charges, which enhances customer savings. As a consequence of the absence of overcollateralization via excess required debt service coverage, utility securitizations receive increased scrutiny because rating agencies and investors do not have the security of additional cash or collateral.

It is the financing order that leads to the creation of the intangible property that serves as collateral for the securitizations. The financing order must be crafted in a manner to enable the securitized bonds to achieve the highest possible credit ratings (AAA or equivalent). Moreover, for investors to accept these bonds with virtually no excess debt service coverage or overcollateralization, the rating agencies and investors need to be persuaded that over the life of the transaction, there is minimal risk of political and regulatory interference from the legislature and/or a subsequent Commission that may delay payments on the bonds or change the protections built into the financing order. The way the financing order is crafted can serve as important evidence that such risk is sufficiently minimized in these transactions, particularly since this will be the first securitization financing order issued by the Commission. The structure recommended in the Company's Application, corresponding testimony and exhibits are designed to result in a financing order that satisfies these important requirements.

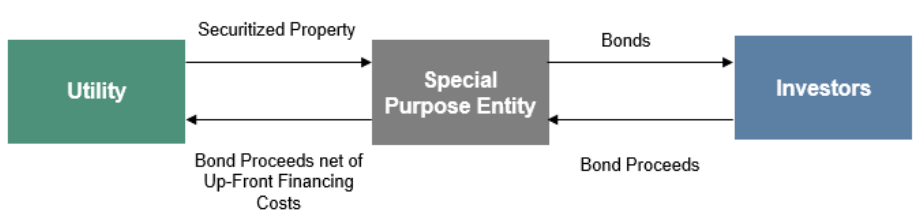
II. SECURITIZATION BACKGROUND

Q. PLEASE PROVIDE A BASIC DESCRIPTION OF SECURITIZATION.

A. In general, securitization is the process in which an owner of a cash flow-generating asset sells the asset for an upfront payment, done in a manner that legally isolates (or decouples) the cash flow-generating asset from the credit profile of the owner/seller. The sale process is intended to protect investors from any changes in credit circumstances, or even the bankruptcy, of the entity that sold the asset, and makes the bonds "non-recourse" to the seller (i.e., the seller is not responsible for making payments on the bonds). Therefore, the "credit" of a securitization is the ability of the legally isolated asset to produce a set of payments (or cash flows) for investors, who purchased an interest in the asset in the form of a securitization bond. Securitization bonds are fixed income debt securities where the investors rely solely on the legally isolated asset and associated cash flows to pay interest and principal on the issued debt securities.

In the context of utility securitizations, the underlying cash flow-generating asset is an intangible property right (described in the Securitization Statute as securitized property) authorized by state legislation and created pursuant to a financing order. This property right includes the right to impose upon the utility's existing and future retail customers the charges required to pay the interest, principal and other ongoing financing costs associated with the debt securities issued in the securitization on a timely basis, as scheduled. This property right is also referred to as the collateral for the transaction. The utility sells the property right to the special-purpose entity, or SPE, which, as its name implies, functionally does nothing other than purchase the collateral and issue bonds to investors to fund that purchase. The SPE is typically prohibited from issuing any debt or having any other creditor who could upset this arrangement with the securitization bondholders. The conveyance of the property right from the utility to the SPE is also referred to as a "true sale," as it legally isolates the collateral from the assets of the seller of that collateral. A true sale of the collateral supports the "bankruptcy-remoteness" of the SPE and the securitization bonds, which allows for the securitization bonds to achieve a higher credit rating than other debt of the utility.

To have the funds needed to purchase the collateral, the SPE, directly or indirectly issues bonds to investors, collateralized by the property right it purchases from the seller. In exchange for the issued bonds, investors pay an upfront purchase price, which is passed through to the SPE back to the utility. Figure A, below, is a simplified indicative schematic of the transaction closing mechanics described above:



In addition to the essential structure described above, the securitization process also includes another key component: ongoing collections of the cash generated by the collateral. Here, the utility and a trustee ("Trustee," typically a commercial bank experienced with securitization trust services) play important roles. The utility will continue to perform its routine billing and collecting functions. In the context of securitization, this function is referred to as servicing, and the utility takes on the role as the servicer. Therefore, in the proposed transaction, Kentucky Power will act as a servicer for its SPE. In addition to its routine billing and collecting functions, as servicer, the utility will also perform certain reporting duties with respect to the amount of money collected. The servicer will perform these functions for the SPE pursuant to an arm's length contractual arrangement known as the servicing agreement. It is important that this servicing arrangement is on arm's length terms, as that supports the fact that the SPE is fully bankruptcy-remote from the utility and there should be no recourse implied from this relationship.

The Trustee also plays an important role in the safekeeping of the ongoing collections and the distributions of principal and interest to investors. After receiving collections from customers, the servicer remits the monies collected to the SPE trust account held at the Trustee, which holds those monies in trust until it periodically distributes them to investors according to a pre-determined set of payment priorities (the "waterfall") and schedule (typically semi-annually). The Trustee serves as a representative of the bondholders and ensures that their rights are protected in accordance with the terms of the transaction. They may also enforce remedies on behalf of bondholders in the event of a default.

Q. WHAT IS THE VOLUME OF UTILITY SECURITIZATIONS THAT HAVE BEEN TRANSACTED TO DATE, AND WHO ARE THE TYPICAL INVESTORS?

A. Utility securitizations are structured based upon well-established rating criteria and have been utilized since 1997. These securitizations may also have specific requirements for tax purposes, please see Niehaus Exhibit 1. According to public records, including SEC registration filings, since 1997 to date, there has been in excess of $81 billion in issuances. These transactions are well understood by many investors, and types of investors that have participated in utility securitizations include banks, institutional and retail trust funds, money managers, investment advisors, pension funds, insurance companies, securities lenders and state trust funds. I attach a list of utility securitization transactions as Niehaus Exhibit 3. These transactions include utility securitizations used to recover extraordinary costs incurred by both electric utilities and natural gas utilities.

Q. HAVE OTHER COLLATERAL TYPES BEEN FINANCED USING SECURITIZATION IN A SIMILAR MANNER?

A. Yes, the market for securitized products or asset-backed securities ("ABS") is large. Examples of other collateral types include certain consumer-related cash flows, such as credit card receivables, auto loans, auto leases, and student loans. During 2022, an estimated $1.082 trillion of ABS was issued in the United States, and as of the end of March 2023, the year-to-date issuance for the U.S. ABS market was over $122 billion (Source: Finsight). The investors who purchase utility securitization bonds generally come from the ABS market, as well as crossover buyers from the corporate debt market. In both cases, they are accounts focused on very highly rated bonds of typically longer (i.e., more than three years) durations.

Q PLEASE DESCRIBE THE FORMATION OF THE SPE THAT WILL ISSUE THE SECURITIZED BONDS.

A. The Kentucky Power securitization transaction is generally expected to follow a process similar to the process for utility securitizations described above. Kentucky Power will form an SPE as a Delaware limited liability company (an "LLC"), and the SPE will be a wholly-owned subsidiary of Kentucky Power. The SPE's LLC Agreement will contain provisions designed to ensure that the SPE will be a bankruptcy-remote limited purpose entity. When I refer to "bankruptcy- remote," I mean that the SPE is structured so that in the unlikely event of a Kentucky Power or American Electric Power Company, Inc. ("AEP") bankruptcy, the SPE would not be consolidated with Kentucky Power or other AEP entities, would not be included in Kentucky Power's or AEP's bankruptcy estate, and the payment of the securitization debt service would not be "stayed" or stopped during the bankruptcy process. Importantly, the SPE is structured to operate independently, requiring that fees paid to third parties providing services to the SPE, including Kentucky Power as Servicer and Administrator, are set on an arms-length basis. These provisions supporting the bankruptcy-remote nature of the SPE are critical to achieving the desired "AAA" equivalent ratings for the securitized bonds.

Q. WHAT MAKES UP THE "SECURITIZED PROPERTY" THAT THE COMPANY SELLS TO THE SPE?

A. The securitized property that is created pursuant to the financing order and, when sold to the SPE, consists of the right to impose, bill, charge, collect and receive a nonbypassable surcharge, the securitized surcharge, paid by all existing or future retail customers receiving electrical service from Kentucky Power or its respective successors or assignees under Commission-approved rate schedules or under special contracts, even if a retail customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in Kentucky, in amounts necessary to pay principal and interest on the securitized bonds, as well as other amounts, timely and in full. Included in this property right is the requirement, over the full life of the transaction, to adjust the amount of the securitized surcharges owed by the Company's customers to ensure that the amounts collected are sufficient to pay all amounts owed with respect to the securitized bonds, on a timely basis as scheduled. This process is referred to as the "true-up" process.

Q. PLEASE FURTHER DESCRIBE THE SALE OF THE SECURITIZED PROPERTY BY THE COMPANY TO THE SPE.

A. Pursuant to the purchase and sale agreement, in consideration for the payment by the SPE of the purchase price for the securitized property, the Company will sell, assign, transfer and convey all rights, title and interest of the Company in, to and under the securitized property to the SPE. The Purchase and Sale

Agreement will provide that such sale, transfer, assignment and conveyance is expressly stated to be an absolute transfer and true sale. Pursuant to KRS 278.688(1), if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer, any sale, assignment or other transfer of securitized property shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title and interest in, to and under the securitized property. As I mentioned previously, this "true sale" treatment is an essential component of legally isolating the securitized property collateral from the bankruptcy risk of Kentucky Power and achieving AAA ratings for the securitized bonds.

Q. PLEASE DESCRIBE THE SECURITIZED PROPERTY AND SECURITIZED SURCHARGES SUPPORTING THE SECURITIZED BONDS.

A. "Securitized property" is defined in KRS 278.670(19) as (a) all rights and interests of an utility, its successor or assignee under a financing order, including the right to impose, bill, charge, collect, and receive securitized surcharges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order and (b) all revenues, collections, claims, rights to payments, payments, moneys, or proceeds arising from the rights and interests specified in the financing order, regardless of whether such revenues, collections, claims, rights to payment, payments, moneys, or proceeds are imposed, billed, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, moneys, or proceeds.

As set forth in KRS 278.670(20), the securitized surcharges are (a) nonbypassable and imposed on, and are a part of, all retail customer bills, (b) collected, in full and separate from the utility's tariffed rates, special contract rates or other mechanisms by an electric utility or by its successors, assignees, or collection agents, and (c) paid by all existing or future retail customers receiving electrical service from the electric utility or its successors or assignees under commission-approved rate schedules, even if a retail customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in Kentucky.

The securitized surcharges will be designed to provide for amounts sufficient to pay the principal of and interest on the securitized bonds as scheduled and in full, as well as other securitized costs and financing costs associated with the securitized bonds. Included in the securitized property is the right to the formula-based true-up adjustment mechanism ("True-Up Mechanism"), which is a requirement to adjust the amount of the securitized surcharges owed by customers to ensure that the amounts actually collected are sufficient to pay all amounts owed with respect to the securitized bonds as scheduled and in full, including securitized costs and financing costs. The process for implementing the True-Up Mechanism is described in the testimony of witnesses West and Spaeth.

Q. HOW ARE SECURITIZED BONDS DIFFERENT FROM UTILITY UNSECURED OR FIRST MORTGAGE BONDS?

A. The proposed securitized bonds are different from utility unsecured or first mortgage bonds because these proposed bonds are non-recourse to the Company. Utility unsecured and first mortgage bonds are fully recourse to the Company. In addition, the securitized bonds will be structured to amortize with scheduled principal payments through specific points in time prior to the rated legal maturity date of the securitized bonds. These points in time are referred to as the expected or scheduled maturities for each of the multiple tranches of bonds issued in the transaction, as further described below. Amortizing, or sinking-fund, structures are distinct from traditional utility corporate bonds, which generally have only a single "bullet" principal payment at the bond maturity date. Another difference is that the securitized bonds will be structured with a time gap between each tranche's scheduled final payment and the rated legal maturity of that tranche. This time gap, sometimes called a "maturity cushion," provides extra time to pay the outstanding principal amount of the tranche in full in the event that unforeseen circumstances such as significant declines from either the forecasted energy demand, forecasted consumption, and/or the forecasted number of customers, cause a material decrease in securitized surcharge collections.

Q. ARE UTILITY SECURITIZED BONDS TYPICALLY CALLABLE?

A. The vast majority of utility securitization bonds are not callable, or subject to redemption before reaching the date of their stated maturity with the notable exception of a utility securitization, issued on March 23, 2023, on behalf of the Texas Natural Gas Securitization Finance Corporation that included a call feature granting the issuer the option to redeem the bonds on or before April 1, 2026 at a “make whole redemption price” and absent unforeseen events, it is likely that the proposed securitized bonds will be noncallable

Q. WILL MAKING THE BONDS CALLABLE RESULT IN THE LOWEST COST FOR RATEPAYERS?

A. Typically, to estimate how investors will view the addition of the call provision, the underwriter would coordinate with its derivatives desk to price out the call option, based on the total duration of the bonds and the preferred par call date. This will be a cost greater than zero and can be very expensive depending on the terms. Due to the uncertainty in the future interest rate environment, it would be difficult to discern at the time of bond pricing whether the cost of this optionality would be outweighed by a future lower-priced coupon bond. The second concern would be whether the same investor base would exist for a callable utility securitization versus the traditional non-call structure, given the rarity of call features in these transactions. The aforementioned Texas Natural Gas Securitization Finance Corporation deal suggests that investors for this structure exist, however it is unclear whether the same bond, absent the call feature, would have achieved better pricing.

Q. IN INSTANCES WHERE THE BONDS ARE CALLABLE, WHERE IS THE SOURCE OF REPAYMENT?

A. Repayment at a par call date requires a large amount of up-front proceeds. As the general purpose of utility securitizations is to fund large, discrete expenses such as stranded or deferred costs at the lowest cost of capital, repayment of utility securitizations would require a large source of even cheaper capital in order to achieve the goal of lowest charges for customers. In the callable Texas Natural Gas Securitization Finance Corporation securitization, the Texas Senate Finance Committee had advanced legislation that included appropriation of moneys to pay off the bonds and possibly other debt incurred by other utilities as a result of 2021's Winter Storm Uri in order to ease the financial impacts to energy customers. Since Texas legislators had signaled intent to have these bonds called as soon as feasible, investors were also able to form a view on the probability the call feature would be exercised, and price accordingly. Absent this unique legislative backdrop, assessing the cost of the call feature may be more difficult and therefore more costly.

Q. ARE THERE "OTHER AMOUNTS" BEYOND DEBT SERVICE REQUIRED TO BE COLLECTED IN CONNECTION WITH THE SECURITIZED BONDS?

A. There will be other amounts in addition to the bond principal and interest that will be payable on an ongoing basis over the life of the transaction. These costs, which are required ongoing financing costs, include, but are not limited to, servicing fees, trustee fees, rating agency surveillance fees, legal fees, administrative fees, audit fees, and other operating expenses. Generally, these amounts are SPE expenses that are required to keep the transaction working as designed, without reliance on Kentucky Power or any other source of funds. It is essential to the SPE's status as a bankruptcy-remote entity for the transaction structure to provide for the full payment of ongoing financing costs. These anticipated fees and expenses are estimated in the testimony of witness Messner and included as Exhibit FDM-2.

Q. PLEASE DESCRIBE AND PROVIDE AN ESTIMATE OF THE UP-FRONT FINANCING COSTS OF ORIGINAL ISSUE DISCOUNT.

A. Original issue discount ("OID") is not really a "cost" similar to the other up-front financing costs discussed in Kentucky Power's testimony. Instead, it is the difference between the total par amount of the bonds issued and the actual price paid by investors. There is a mathematical relationship, as captured by the yield of a bond, between the amount of OID in a particular transaction and the interest rate (or coupon) paid on the bonds sold. The lower the interest rate, the higher the OID will be for a given yield (all else equal). For planning purposes, it is assumed that the securitized bonds will be issued without OID. However, as a practical matter, it is likely that some level of OID will be needed to provide yields that match the exact market conditions at issuance. In fact, a certain amount of OID is typical of securitized bonds and some other asset backed securities generally. The amount of OID is generally less than 0.5%. These types of discounts arise because (a) treasury yields or the swap curve (essentially a yield curve for interest rate swaps used to price swap transactions) are typically quoted to four decimal places while bond coupons are typically stated to two decimal places and (b) many initial offerings settle without accrued interest on a mid-month date, which results in an "odd first period." Under these circumstances, pricing at exactly 100% is not practicable. Many investors tend to prefer a lower coupon with a discount over a higher coupon with a premium, so the normal convention is to round the coupon down (to two decimal places) at pricing to produce a slight discount. For all practical purposes, OID is an element of interest cost. The OID will depend on market conditions at the time and the "odd first period" described above. Since the OID will be fully reflected in the issuance advice letter (as further described below), and there is no reason to predict, nor any basis for predicting, the exact amount of OID that may be associated with this transaction, any estimate would be arbitrary.

Q. IN YOUR EXPERIENCE, ARE THE COSTS ESTIMATED BY KENTUCKY POWER WITHIN THE RANGE OF COSTS YOU HAVE PREVIOUSLY SEEN FOR SIMILAR EXPENSES?

A. Yes. I have provided input on and reviewed the preliminary expense estimates provided by witness Messner, as well as the supporting examples provided from previous transactions. While the Company's proposed securitization is not expected to occur until 2024, and costs may change, these estimated costs are within the ranges found in other utility securitization transactions.

Q. IN ADDITION TO THE SECURITIZED PROPERTY, ARE THERE ANY OTHER COMPONENTS OF THE COLLATERAL FOR THIS TRANSACTION?

A. Yes. The collateral for the transaction includes other components in addition to the securitized property. However, that property right is the principal asset pledged as collateral. Pursuant to the Indenture, the other collateral includes a collection account, which is established by the SPE as a trust account to be held by the Trustee to ensure the scheduled payment of principal, interest and other costs associated with the securitized bonds are paid in full and on a timely basis. The collection account, in turn, is comprised of the three subaccounts:

- the general subaccount;
- the capital subaccount; and
- the excess funds subaccount.

The collateral also consists of the SPE's rights under certain agreements it enters into as part of the transaction, including the purchase and sale agreement and the servicing agreement.

Q. PLEASE DESCRIBE THE SUBACCOUNTS OF THE COLLECTION ACCOUNT REFERRED TO ABOVE.

A. The general subaccount is the subaccount in which the Trustee deposits securitized surcharge remittances it receives from the servicer. Monies in this subaccount will be applied by the Trustee on a periodic basis to make payments according to the waterfall, which generally includes the payment of SPE expenses required to maintain the operations of the transaction, then interest on the securitized bonds, and then principal on the securitized bonds.

The capital subaccount represents the equity capital of the SPE and is funded by an amount contributed by Kentucky Power at issuance that is at least equal to 0.50 percent of the initial principal amount of each securitized bond transaction. If that subaccount is drawn upon, it is replenished from securitized surcharges through the True-Up Mechanism and any available excess securitized surcharge collections. The Company's proposed equity investment of 0.50 percent has been derived from guidance from the Internal Revenue Service ("IRS") through its Revenue Procedure 2005-62 (Niehaus Exhibit 1). The testimony of witness Messner addresses the Company's return on this capital contribution at a rate equivalent to the proposed Weighted Average Cost of Capital ("WACC") in this case. The fact that the Company receives a return on their respective capital contributions contributes to the "equity investment" characterization of these funds, which is necessary to ensure that the securitization transaction receives tax treatment by the IRS that will allows the receipt of proceeds from the sale of the securitized property by the Company to be disregarded for tax purposes. The IRS Revenue Procedure sets forth the way an investor-owned utility may treat, for federal income tax purposes, the issuance of a financing order by a state regulatory agency and the securitization of the rights created by the financing order. Having an equity investment in the SPE of at least 0.50 percent is within the safe harbor provided in the IRS Revenue Procedure and helps to ensure that the Company will not recognize in their taxable income the cash proceeds received from the sale of securitized property or the issuance of the securitized bonds. Rather, the securitized bonds will be considered borrowings of the Company for federal income tax purposes.

The excess funds subaccount is where any monies on deposit in the general account that are not required to meet the scheduled interest and principal obligations of the securitized bonds will be deposited. The initial balance is zero, and the target ongoing balance is also zero. To the extent there are funds on deposit in this subaccount, those amounts will be considered in the next available True-Up Mechanism and the subaccount value will again be generally targeted to be zero. Stated differently, to the extent securitized surcharge collections are higher than expected in any given true-up calculation period, those amounts do not pay down the principal balance of the securitized bonds beyond the scheduled principal payment for that period. Rather, the amounts on deposit in the general subaccount above and beyond the scheduled obligations will be moved to the excess funds subaccount. Those amounts will then reduce the amount of securities surcharge collections needed in the subsequent true-up calculation period. This is how the debt service coverage is targeted to remain at 100% of debt service and ongoing financing costs, as discussed above.

Q. PLEASE DESCRIBE THE TREATMENT OF ANY FUNDS REMAINING IN THE VARIOUS SUBACCOUNTS AT THE FINAL MATURITY OF THE TRANSACTION.

A. Funds remaining in the general subaccount and the excess funds subaccount will be returned to the SPE upon final payment in full of the securitized bonds and all other financing costs, and equivalent amounts will be credited to customers' electricity bills as part of the final reconciliation of the Securitization Financing Rider, as described by witness Spaeth. Monies remaining in the Kentucky Power-funded capital subaccount along with the authorized return, will be returned to the Company through the SPE without any equivalent credit to customers' electric bills, since the capital subaccount was funded at issuance with the Company's own funds.

III. <u>DESCRIPTION OF PROPOSED TRANSACTION</u>

A. Transaction Structures

Q. PLEASE DESCRIBE THE TRANSACTION STRUCTURE OF THE COMPANY'S PROPOSED SECURITIZED BONDS.

A. As shown in the detailed structure diagram in section III.B below, this structure is substantially similar to that employed in typical utility securitization bond offerings. The proposed transaction will involve the creation by Kentucky Power of a wholly-owned SPE, which would be incorporated as Delaware limited liability companies with Kentucky Power as the sole member. The SPE will serve as the issuer of securitized bonds (the "Issuer"). Kentucky Power, pursuant to authorization granted it by the Commission in a financing order, will create and sell securitized property to the Issuer. The Issuer will finance the purchase of such securitized property by selling securitized bonds, thereby acquiring all right, title, and interest of Kentucky Power to collect securitized surcharges.

Q. PLEASE PROVIDE DETAILS REGARDING THE PROPOSED CAPITAL STRUCTURE OF THE KENTUCKY POWER SECURITIZED BONDS.

A. The preliminary structure for the estimated $446.7 million Kentucky Power securitized bond transaction is presented in Niehaus Exhibit 3. On a preliminary, indicative basis, one tranche of bonds will be issued, which will amortize over a sinking fund schedule crafted to provide substantially level debt service each period. Niehaus Exhibit 3 also shows indicative credit spread to the benchmark and the associated interest coupon, scheduled final payment and rated legal maturity. I recommend that the initial debt service payment be scheduled for approximately nine months after the closing of the transaction, with debt service payments thereafter occurring on a semi-annual basis. While securitized surcharges are irrevocably authorized upon issuance of the securitized bonds, the accrued charges will not be included on customer bills until the immediately following billing cycle month. Thus, considering the standard roll-out of customer bills over a 20 business day billing cycle, and given other lags in collections, it will take some time for the full expected cash flow from securitized surcharges to be realized. Therefore, the approximately nine month initial period allows more time for the full amount of expected securitized surcharge revenues to become available and provides for a mandatory true-up adjustment prior to the first debt service payment, to mitigate the transaction revenue impact of any unexpected changes in the Kentucky Power customer base or revenues.

Please note that these terms are preliminary and estimated based on current market conditions. The final terms and conditions of the securitized bonds will not be known until they have been priced in the marketplace. Investor demand at the time of pricing will determine market-clearing interest rates and the final structure offered to investors. Therefore, this preliminary structure and pricing information is illustrative and subject to change, and the actual structure and pricing will differ, and may differ materially from this preliminary structure.

The structure shown is designed to provide the lowest weighted average cost of funds to the issuer given the targeted approximate 20-year scheduled final payment date. The level of the securitized surcharge paid by the Company's customers is directly affected by interest rates and the principal amortization structure of the securitized bonds. With larger transactions, the bond balance may be split into multiple tranches of debt to take advantage of discrete pockets of investor demand across the entire term of the transaction. For example, a five and a ten-year tranche may be issued. Here, given the small transaction size, we are constrained in splitting up tranches because a marketable structure should still maintain large enough tranche sizes to ensure secondary market liquidity for the securitized bonds. Generally, investors view any tranche smaller than $100 to $125 million as too small to be liquid. Liquidity in this context refers to the ability of a bondholder to sell its bond in the secondary market without having to significantly discount its price. A tranche that is seen as not liquid may require an illiquidity premium during pricing, which results in higher interest costs passed along to customers.

Niehaus Exhibit 3 also shows the weighted average life (or "WAL") of the indicative bonds. Weighted average life is a measure of the average amount of time it takes to repay in full the principal balance of a bond tranche. When pricing the bonds, a credit spread (negotiated with investors) is added to the underlying benchmark rate, and together they make up the fixed coupon for the life of the transaction. Here, our benchmark will be the U.S. Treasury curve. Note that the duration of the U.S. Treasury benchmark that we will use as a benchmark on the day of pricing is based on duration closest to the WAL of the bonds, not closest to the scheduled final payment date or legal final maturity date. Regularly scheduled principal amortization throughout the life of the transaction, as opposed to a single bullet maturity, results in a shorter WAL for the financing. Investors have nearly universally seen and accepted semi-annual amortization in these transactions. I have advised the Company that the proposed transaction should have a relatively level annual debt service and associated revenue requirement, such that as the Company's customer population and customer consumption may increase, all other things being equal, the securitized surcharge may be adjusted downward over the life of the transaction. Substantially level debt service also avoids significant volatility in the customer charge year to year, as opposed to a bespoke amortization schedule or a bullet payment at maturity. Rating agency stress tests also tend to penalize transactions that use a different structuring approach, particularly one that significantly back-loads debt service. Niehaus Exhibit 3 also outlines some of the structuring assumptions and displays the preliminary annual debt service schedules and annual revenue requirements.

Q. WHAT IS THE DIFFERENCE BETWEEN THE SCHEDULED FINAL PAYMENT DATE AND LEGAL MATURITY DATE?

A. I briefly addressed this topic above in the context of the basic discussion of securitization and will address it more fully here. The scheduled final payment date of the tranche or tranches of securitized bonds represents the date at which final payment is expected to be made, but no legal obligation exists to retire the tranche in full by that date. The rated legal maturity date is the date by which the bond principal must be paid or an event of default will occur. The proposed preliminary structure for this transaction utilizes a legal maturity date that is usually 24 months longer than the scheduled final payment date for each bond tranche, known as a "maturity cushion." The actual maturity cushion will be determined by the final "AAA" stress scenarios required by the rating agencies during the rating process for the underlying securitized bonds and may be shorter or longer than 24 months. Therefore, it is important that the financing order provides flexibility for the transaction to have the specific maturity cushions required to obtain AAA equivalent ratings (or the highest possible ratings), which cannot be determined in advance of the rating agency review process.

The difference between the scheduled final payment date and legal maturity date provides additional credit protection by allowing shortfalls in principal payments to be recovered over this additional period due to any unforeseen circumstance. This gap between the two dates is a benefit to the Company and contributes to the strong credit quality of the transaction, helping lower the cost of funds and therefore benefitting customers.

Moreover, many investors in utility securitizations are familiar with this concept, which is a feature in all utility securitization transactions and most ABS transactions. The ratings on the securitized bonds are derived in part based on the assumption that the outstanding principal amount of each tranche will be paid in full by its legal maturity date, and investors would price assuming the underlying securitized bonds make the final scheduled principal payment in full at the scheduled final payment date, which is earlier than the legal maturity date.

Q. SHOULD THE TRANSACTION BE STRUCTURED AS A PUBLIC, SEC-REGISTERED TRANSACTION?

A. I recommend in this case pursuing an offering registered with the SEC, generally referred to as a "public" offering, offered through a negotiated process with a select group of underwriters. The Securities Act of 1933, as amended, requires that every security offered or sold in the United States either be registered with the SEC or qualify for an exemption from registration (with such exempt securities generally referred to as a "private" offering). If a transaction is registered with the SEC, there are no restrictions on the type of investor who may purchase the securities. While private offerings are restricted to certain types of sophisticated institutional investors (e.g., 144A offerings), public offerings can be sold to anyone, including retail investors. Because there are no restrictions on the sophistication of the investors able to purchase the bonds, the SEC requires public offerings to prepare a prospectus that conforms to detailed disclosure requirements and is also reviewed by the SEC prior to marketing. Offering documents for private transactions do not have to be reviewed by the SEC prior to marketing. The public offering process can therefore be more time consuming and may also have higher transaction costs. Legal fees may be higher due to the SEC review process, and unlike private offerings, the SEC requires issuers to pay a filing fee based on the dollar amount of bonds being registered. However, in general, public offerings are considered to be more liquid given the broader potential investor universe and therefore may be more attractive to investors, resulting in lower pricing. Public offerings are invariably conducted through a negotiated sale of the securities to a selected group of underwriters. I describe this negotiated sale process later in my testimony. Therefore, similar to the vast majority of precedent utility securitization transactions, we believe a public offering using a negotiated sale of underwriters will likely lead to lower overall costs for customers.

Q. WILL THE SECURITIZED BONDS PAY FIXED OR FLOATING INTEREST RATES?

A. Virtually all rate reduction bonds have been fixed-rate bonds. Fixed rates facilitate evaluation of the likely costs and benefits in advance and the maintenance of roughly equal securitized charges over time (subject to variances in items such as actual load or collections history from forecast). Maintaining predictable revenue requirements facilitates the ongoing management of the customer charge adjustment (or "true-up") process. Although it is possible to issue floating-rate bonds if the floating interest rate is then converted to a fixed rate through use of an interest rate swap or hedge between an SPE and a highly-rated swap counterparty, in today's market, floating rate bonds, swaps, and hedges are expected to create additional documentation costs and introduce additional risks for customers. For example, a swap incorporated as a part of the securitization structure would require an additional counterparty, so there is a risk of a ratings downgrade or a default by the counterparty providing the swap. These additional costs do not support the goal of obtaining the lowest charges for customers. Further, it is difficult to find a comparatively-rated swap counterparty (AAA) satisfying rating agency criteria necessary to secure the desired AAA ratings on the bonds.

Q. ARE THERE OTHER IMPORTANT CONSIDERATIONS REGARDING THE PRELIMINARY STRUCTURE OF THE SECURITIZED BONDS?

A. Yes. I reiterate that it will be beneficial for the securitized bonds to be structured to have substantially level annual debt service. This is important because it should facilitate stability in the aggregate securitized surcharges over the life of the securitized bonds.

Q. PLEASE DESCRIBE THE MECHANICS OF HOW THE SECURITIES ARE PRICED.

A. The starting point for how a utility securitization is priced is the corresponding benchmark rate. In the preliminary structure included as Niehaus Exhibit 3, U.S. Treasury benchmarks are listed. These benchmark rates are matched with the weighted average life of each tranche. As discussed above, the weighted average life is a measure of the average amount of time it is expected to take to repay the principal balance of a tranche in full. The U.S. Treasury benchmark reflects the "risk-free" yield investors generally associate with securities issued by the U.S. Treasury. The next component is the credit spread, which is generally the amount of yield above the given benchmark that is required by the marketplace to invest in the given bond tranche. This credit spread, the yield above the benchmark rate, is an indication of the market's view at the time of pricing of the incremental credit risk associated with each bond tranche. To state the obvious, issuers would like this credit spread to be as small, or tight, as possible to the underlying benchmark (thereby lowering the coupon), and investors would like it to be higher, or wider, versus the underlying benchmark, all else being equal. The pricing credit spread is ultimately determined by market-clearing rates at the conclusion of the marketing process.

B. Securitized Surcharge Collection

Q. PLEASE DESCRIBE THE ONGOING BILLING, COLLECTING, AND REMITTING OF THE SECURITIZED SURCHARGE OVER THE LIFE OF THE TRANSACTION.

A. The Company, as servicer, will be responsible for calculating, billing and collecting the securitized surcharge from customers. The procedures for remitting the securitized surcharge to the Trustee will be established through a Servicing Agreement. The securitized surcharge collections will be remitted by the Company to the Trustee each business day (based on estimated amounts collected), with cash held no more than two business days prior to remittance. The Trustee will then hold the amounts remitted to it by the Company until the next payment date. These payment dates will generally occur twice a year, as is customary in utility securitizations.

Further, while it is my understanding that Kentucky law does not currently authorize third-party energy providers to provide public utility services, it is important that the financing order ensure that such third-parties – in the event there is any change in utility regulation – bill and collect the securitized surcharge in a manner that will not cause any of the then-current credit ratings of the securitized bonds to be suspended, withdrawn, or downgraded.

While the rating agency requirements may change from time to time, it is expected that the rating agencies' requirements, in general, will consist of the following:

- Any third-party energy provider must provide Kentucky Power, acting as servicer, (or any successor servicer) with total monthly kilowatt-hour usage information in a timely manner for the servicer to fulfill its obligations, as such information is the basis of such remittance.
- The utility, or any successor servicer, will be entitled, within seven days after a default by the third-party energy provider in remitting any securitized surcharge billed, to assume responsibility for billing all charges for services provided by Kentucky Power or any successor servicer, including the securitized surcharge, or to switch responsibility to a third- party, which must meet the criteria herein described.
- If and so long as a third-party energy provider does not maintain at least a triple-B long-term unsecured credit rating from Moody's Investors Service, S&P Global Ratings or Fitch Ratings, such third-party energy provider shall maintain, with the servicer or as directed by the servicer, a cash deposit or comparable security equal to at least one month's maximum estimated collections of the securitized surcharge, in a form and manner as agreed upon by the servicer, or any successor servicer, and the third-party energy provider. In the event of a default in the remittance of the securitized surcharge by a third-party energy provider, such amount will be included in the true-up adjustments.

- The third-party energy provider must agree to remit the full amount of the securitized surcharge it bills to retail customers, regardless of whether payments are received from such retail customers, within 15 days of its or the utility's, or any successor servicer's, bill for such charges.
- The foregoing requirements may be modified in accordance with the terms of the securitized bond financing documents, subject to approval by the Commission, and confirmation (or deemed confirmation) by the applicable rating agencies that such change will not result in a suspension, reduction, or withdrawal of the then-current credit ratings for the securitzed bonds.

C. Key True-Up Mechanism Considerations

Q. PLEASE DISCUSS KEY ASPECTS OF THE TRUE-UP MECHANISM.

A. One of the fundamental utility securitization features that enables "AAA" ratings is the statutorily mandated periodic true-up mechanism. The true-up mechanism involves the adjustment of the customer charges on a periodic basis, to ensure that the scheduled securitization debt service and ongoing financing costs are paid on a timely basis. True-up adjustments are also designed to minimize any over-collections and target the low 100% (or 1.0x) debt service coverage. True-ups are to be implemented by the servicer, and by the terms of the Securitization Statute, any reviews by the Commission focus only on potential mathematical or clerical errors present in the true-up submission. I recommend that true-ups take place at least on a semi-annual basis; provided, however, that beginning 12 months prior to the scheduled final payment date for the latest maturing tranche of securitized bonds of a particular series, the required true-up adjustments should be done on a quarterly basis. In addition, I recommend that the true-up calculations occurring in each period take into account actual collections received during months since the prior true-up, as well as scheduled debt service and financing costs projected to be due over the two upcoming debt service payment periods (the periods ending on the first and second payment dates following the adjustment date). The true-up calculation methodology will take into account updated energy usage and revenue forecasts, any changes in the Commission- approved customer rate allocations, as well as updated customer payment aging, delinquency and uncollectibles data.

I recommend that the initial bond payment date be set approximately nine months from the closing date, so that there will be a true-up adjustment effective prior to the first bond payment date. I also recommend that the true-up adjustment become effective in the approximate middle of the bond payment periods, such that generally there are two or three months of customer charges, based upon the adjusted rates, collected prior to the upcoming bond payment date. For example, if bond payment dates are January 1 and July 1, the mandatory semi-annual adjustment dates could be set for April 1 and October 1. Setting true-up adjustment dates on such a schedule provides time for charges based upon adjusted rates to be collected prior to upcoming bond payments and is designed to minimize and stabilize charges on an ongoing basis throughout the life of the transaction.

In addition to the required true-ups, it is important for the servicer to have the ability to conduct an interim true-up at any time to ensure that debt service and ongoing financing costs are paid on time. Witness Spaeth provides more detail concerning the True-Up Mechanism in his testimony.

Q. IN YOUR VIEW WILL THE BROAD-BASED NATURE OF THE PROPOSED TRUE-UP MECHANISM IN THE SECURITIZATION STATUTE SERVE TO MINIMIZE CREDIT RISK ASSOCIATED WITH THE SECURITIZED BONDS?

A. Yes. I agree that these features serve to minimize credit risk associated with the securitized bonds (i.e., that sufficient funds will be available and paid to discharge the principal and interest when due).

IV. DISCUSSION OF THE EXECUTION PROCESS

A. Rating Agency Process

Q. PLEASE DESCRIBE THE RATING AGENCY PROCESS.

A. An important element of preparing for the marketing and pricing of the securitized bonds is obtaining the highest ratings from the rating agencies. The Company and the structuring advisors and lead underwriter for the Company will prepare written presentations and may meet with rating agency personnel to discuss the credit framework and credit strengths of the proposed securitized bonds, and the structure of the securitized bonds with each hired rating agency, in compliance with SEC Rule 17g-5. It is important to note that rating agencies are completely independent institutions, and each rating agency has its own method of reviewing a utility securitization and will request certain data and information that will facilitate such a review process. Rating agencies may update or amend their rating criteria at any time. The Company's structuring advisors and lead underwriter will work with the Company to draft presentations that contain the required data and information. Additionally, the rating agencies may require a diligence review of the servicer's billing and collecting processes. Whether this review is done on-site or via the telephone depends on several factors and is ultimately up to each rating agency. Each rating agency will follow-up with additional questions.

The ratings process also entails a review of the cash flows of the proposed structure. As part of this phase, each rating agency will ask for various cash flow stress scenarios based on its requirements and the details of the particular transaction to ensure that the securitized bonds will be repaid under extremely stressful cash flow projections. These rating agency cash flow stress scenarios may include assumptions that zero out revenues each year during the peak consumption months, that assume that all industrial customers leave the service territory, assume that the widest historical variance between actual consumption and forecasted consumption is multiplied five or more times over the life of the transaction, as well as other stress assumptions regarding write-offs and delinquencies.

Important rating elements include:

- Legal and regulatory framework;
- Political and regulatory environment;
- Transaction structure;

- Servicing review and capabilities;
- Service area analysis;
- Cash flow stress analysis; and
- Size of the securitized surcharge during stress scenarios as a percentage of the average residential customer bill.

Q. IN YOUR PREVIOUS ANSWER, YOU MENTIONED SEC RULE 17G-5. PLEASE EXPLAIN WHAT IT IS AND HOW IT WILL PERTAIN TO THIS EXECUTION PROCESS.

A. In December 2009, the SEC amended, as part of its mandate under the Dodd-Frank reform legislation, its rules regulating ratings on structured finance securities where the issuer, sponsor, or underwriter pays for the ratings on the securities. In short, the amended regulation, which I refer to here as "Rule 17g-5" is intended to provide access to ratings-related information to non-hired rating agencies so that they, if desired, could issue unsolicited ratings. In practice, however, actual unsolicited ratings are very rare. The rule has been in effect since June 2010. Although Rule 17g-5 only directly applies to a hired rating agency, the rule requires the agency to obtain commitments from the issuer to facilitate this process, effectively passing on the requirements to issuers. Those requirements generally include the maintenance of a password-protected website containing rating-related information used to providing a rating on the securities. Each hired rating agency is then required to maintain its own password-protected website listing each structured finance security for which it is in the process of determining a rating. If a non-hired rating agency desires to gain access to the ratings-related information, it can request it of the issuer. Please note, an issuer will be aware of such a request because it will be the one to grant access to the non-hired rating agency.

Utility securitizations have been subject to Rule 17g-5 since its implementation, and issuers and their underwriters have managed the process by maintaining most communication via email and/or recorded or transcribed phone communication. Therefore, it is important that issuers and their underwriters have specific procedures in place to document and record all materials provided to the rating agencies during the rating agency process. In summary, Rule 17g-5 changes the technical nature of how information is shared with rating agencies and how communication takes place during the ratings process, but it has not changed the fundamental nature of that process (i.e., utility securitizations and all other transactions subject to the rule are still rated). Typically, the lead underwriting bank will assist the issuer in ensuring compliance with this rule.

B. Marketing Process

Q. PLEASE DESCRIBE THE SECURITIZED BOND MARKETING PROCESS.

A. The marketing process entails several different phases, each uniquely tailored to the asset class, market conditions and the specifics of the contemplated transaction. The underwriters will work with and make recommendations to the Company throughout the process. Described below are the general steps in a typical marketing process, but the actual process for the securitized bonds could vary based on the market environment at the time of marketing. Each step below should be conducted consistent with the proposed issuance advice letter procedure described in paragraph C below, as well as with SEC rules and regulations regarding publicly registered securities offerings, including an investor suitability analysis:

1. **Pre-marketing.** Once a preliminary prospectus for the transaction is on file with the SEC, the underwriters will work together with the Company to bring the transaction to the attention of investors, to inform them of its structure and term, and to directly answer any questions they may have. Extensive education will be provided to investors regarding the securitized bonds, particularly investors who may be new to the asset class. A wide range of corporate and ABS investors will be contacted, including investment managers, insurance companies, corporate treasury and other investors. It is important to choose underwriters with both experience in utility securitizations and broad sales forces in order to understand where the issuer will gain the most traction on early demand through premarketing. Underwriters will use information gained from prior utility transactions to understand which investors have a combination of interest in the space and money to allocate. Early interest in the transaction gained through this preliminary process can drive momentum for the subscription process and give the issuer a better understanding of the market ahead of formal announcement. This process is generally referred to as pre-marketing. It may include one-on-one conference calls with significant potential

investors, and open conference calls, which several investors may join. The purpose of this process is to stimulate broad investor demand for the issue, so that the pricing process will be better situated to obtain the lowest possible interest rates reasonably consistent with market conditions at the time of pricing. This, in turn, should result in lower securitized surcharges.

The timing of this process and the specifics of the new issue process are also important factors. Typically, after an extensive pre-marketing process, new transactions in this sector are announced to the market on Monday mornings. As one could expect, the new issue calendar may be busy at that time, so in order to get the attention of investors as they may be considering several competing new issues, the pre-marketing period will be determined by the Company and the lead underwriter taking the likely new issue calendar into account. Most transactions that announce on Monday morning will target a pricing by Wednesday or Thursday (as issuers do not want to take the risk of an intervening event over a weekend); thus, a pre-marketing start date is designed to gain the attention of investors when they may not be busy reviewing other active new issue pricings.

2. **Announcement.** Following pre-marketing, the transaction is officially announced to the market, which is typically done toward the start of the week (again, as mentioned above, the timing of the announcement is to ensure that a transaction prices during the same week in which it is officially announced; otherwise, issuers may be subject to unforeseen risk over a weekend). During this phase of marketing, the securitized bonds will be

offered for sale to investors through the underwriters. The post announcement phase will include an electronic road show, which is made available to investors, as well as the continuation of one-on-one discussion with potential investors. The underwriters, in conjunction with the issuer, will begin to discuss informally with investors the coupons at which the securitized bonds will be offered at initial issuance, stated as a credit spread relative to the benchmark rates for each tranche. In response, investors will provide initial indications of interest, generally specifying how much of the tranche for which they intend to submit an order at a given pricing level. The lead underwriter will be charged with keeping the master record (known as "the book") in which all indications of interest received by the underwriters from potential investors are recorded. While all underwriters assist in investor outreach and taking order, the lead underwriter ensures coordination of marketing messaging across the syndicate, as well as creates and drives timeline for the bond marketing process. The next phase of the transaction – price guidance – will be based on the aggregated amount of indications of interest received from investors.

3. **Price guidance.** At this stage, the underwriters will send out a notice to investors with price guidance, again typically stated as a range of credit spreads stated against the given benchmark. Thereafter, investors will be invited to place firm indications through the underwriters for the amount and specific tranches of securitized bonds they are willing to purchase, at certain prices and bond coupon rates. At a certain point in time, when the

book has sufficient interest from investors, the underwriters will stop taking orders (generally referred to as going "subject" to pricing and confirmation). The timing of this step will depend on the specifics of each transaction; however, it will obviously occur only when the book has at least an equal amount of orders for the securitized bonds as the anticipated aggregate principal amount of each proposed tranche (generally referred to as "fully subscribed"). There is no specific threshold beyond that, and it will depend on market conditions, the speed at which orders came in from investors and the composition of investor types in the book, to name a few factors. The underwriters will exercise professional judgment in making a recommendation to take the book subject to final order confirmations, based on all relevant factors. Conversely, if the bonds (or any tranche within the issuance) is undersubscribed, the underwriters may need to increase the coupon or restructure the tranching to attract sufficient investor orders to sell the entire tranche, as described below.

4. **Determining pricing levels.** Having exercised professional judgment and taken the transaction subject to pricing and final confirmation of orders, the underwriters and the Company will then work to refine the pricing levels. Based on the strength of the book, the underwriters may adjust the pricing levels lower (or tighter). This process is generally referred to as testing the pricing levels. It is done to ensure maximum distribution of the securitized bonds at the lowest bond yields consistent with market conditions. If a tranche is oversubscribed, the underwriters may continue to lower the

pricing level (thus improving execution for the Issuer and customers), provided that this adjustment does not decrease the aggregate investor interest below the size of the tranche. If this adjustment is not done correctly, the transaction may fail, which could negatively affect a subsequent attempt. If a tranche is undersubscribed, the pricing level may be adjusted higher until the tranche is fully subscribed. The underwriters will use professional judgment with respect to the recommendation to the Company for the amount of tightening and number of testing attempts.

5. **Launch.** Once the pricing levels have been determined for each tranche in the transaction, and the registration statement for the transaction has been declared effective by the SEC, the transaction will be launched at a specific pricing level. The intention of this stage is to declare to investors at which pricing levels, or credit spreads, the transaction will be issued. This will be the market-clearing pricing level, subject only to movements in the underlying benchmark rates.

6. **Allocations.** At this stage, the market-clearing pricing level has been determined by the marketing process, but the final book – how much each investor will purchase – has yet to be determined. Here, the lead underwriters will work to recommend to the Company a specific amount of securitized bonds to be sold to each investor. Each allocation depends on several factors; e.g., the size of each investor's indication of preliminary orders, when the investor submitted its indication, its experience in the sector, its flexibility for the pricing process, the investor type, etc.

Ultimately, each investor will purchase its final allocations for the transaction.

7. **Pricing.** Once the market-clearing pricing level and the book has been finalized, the transaction can be priced. At this stage, the underwriters will price the transaction by spotting the underlying benchmark rates and adding the credit spread to determine the coupons for each tranche. Soon after the pricing, the investor orders will be confirmed, and the final prospectus will be provided to investors.

8. **Closing.** At the conclusion of the pricing, the Company, with its underwriters and legal team, will work toward finalizing the transaction documents and close the transaction, typically approximately five business days after pricing.

In summary, it is through this marketing and pricing discovery process that the actual investor market-clearing interest rates for the securitized bonds are determined. It should be noted again that this will be based on the actual investor orders on the actual day of pricing.

C. Key Issuance Advice Letter Considerations

Q. PLEASE EXPLAIN THE PURPOSE OF THE ISSUANCE ADVICE LETTER.

A. Pursuant to the Securitization Statute (KRS 278.674(7)-(8)), the Company is required to provide an Issuance Advice Letter ("IAL"), prepared by the Company and delivered to the Commission no later than three (3) business days after the pricing of the securitized bonds.

The IAL will report the initial securitized surcharges, indicate the final structure of the securitized, including the final pricing terms, the initial securitized surcharges, and the best available estimates of total ongoing financing costs.

Q. PLEASE DISCUSS KEY ASPECTS OF THE ISSUANCE ADVICE LETTER PROCEDURE.

A. The issuance advice letter shall be in the form approved in a financing order and report the initial securitized surcharges, indicate the final structure, including terms, of the securitized bond issuance and best estimates of total ongoing financing costs.

V. DISCUSSION OF THE FINANCING ORDER

Q. ARE THE TERMS OF A FINANCING ORDER CRITICAL TO ACHIEVING A SUCCESSFUL SECURITIZED BOND TRANSACTION?

A. Yes. A financing order, when taken together with applicable provisions of the Securitization Statute, establishes in strong and definitive terms the legal right of investors to receive, in the form of securitized surcharges, those amounts necessary to pay the interest and principal on the securitized bonds and other ongoing expenses in full and on a timely basis. A proposed draft of the financing order is provided as Exhibit 5 to the Application.

As mentioned earlier, the financing order specifies the mechanisms and structures for payments of bond interest, principal, and ongoing expenses in a manner that minimizes the amount of additional credit enhancements required by the rating agencies to achieve the highest possible ratings. The highest possible ratings will allow the financing to achieve the desired results. In addition, the financing order, when taken together with applicable provisions of the Securitization Statute, will enable the Company to structure the financing in a manner reasonably consistent with investor preferences and rating agency considerations at the time of pricing, which is also necessary for the financing to achieve the desired results.

Q. WHAT ARE THE KEY ELEMENTS OF THE FINANCING ORDER THAT ARE ESSENTIAL TO ACHIEVING THE DESIRED RESULT FOR THE TRANSACTION?

A. The Securitization Statute sets out several key elements for a financing order. Once the securitized property is created, one of the most important elements is insulating the transaction from the risk of any potential bankruptcy risk of the Company, which is accomplished via a legal "true sale" of the securitized property to the SPE. The structure utilized with this transaction, along with other securitizations, relies on features that allow the rating agencies and investors to conclude that the issuer of the securitization (the SPE) is highly unlikely to become the subject of a bankruptcy proceeding in the unlikely event of a bankruptcy of the Company. Under the Federal bankruptcy code, payments on the debt obligations of an issuer in a bankruptcy proceeding become subject to an automatic stay – i.e., the payments are suspended until the courts decide which creditors of the issuer are to be paid, when they will be paid, and whether they are to be paid in whole or in part. Unless the risk of an automatic stay in the unlikely event of a bankruptcy of the Company is essentially removed from the rating agencies' credit analysis, the financing cannot achieve the highest possible ratings, since the Company's secured debt obligations are rated below AAA.

In addition, the creation of a bankruptcy-remote SPE, which is legally distinct from the utility, is designed to limit the ability of such SPE to be included with the Company in the unlikely event of a Company bankruptcy. Therefore, even if the Company were to declare bankruptcy, the SPE would not become the subject of the Company's bankruptcy proceeding, and the SPE's debt service payments to investors would not be subject to the Company automatic stay. The transaction, as structured and reflected in the financing order, is intended to achieve this important element. This legal structure is supported by true sale and non-consolidation legal opinions from experienced legal counsel.

Q. ARE THERE ANY OTHER COMPONENTS OF THE FINANCING ORDER THAT ARE ESSENTIAL TO ESTABLISHING THE LEGAL FOUNDATION FOR THE TRANSACTION?

A. There are several provisions in the financing order that ensure that the SPE will be deemed to be bankruptcy-remote in addition to the elements mentioned above, including that the SPE will have at least one independent manager whose approval will be required for certain organizational changes or major actions of the SPE, such as a voluntarily filing for bankruptcy by the SPE. The financing order will also enable the transfer of the securitized property from the Company to the SPE to be a "true sale." As discussed above, a true sale is a sale that a bankruptcy court should not overturn in the case of any Company bankruptcy. The financing order will allow its SPE to issue the securitized bonds, pledging the securitized property as security for payment on the securitized bonds.

Q. DOES THE FINANCING ORDER PROVIDE FOR ANY CREDIT ENHANCEMENT TO THE TRANSACTION?

A. Yes, in a number of forms. The primary form of credit enhancement is the True-Up Mechanism. The financing order, together with the Securitization Statute, ensures that the collection of securitized surcharges arising from the securitized property is expected to be sufficient to pay all amounts owed on the securitized bonds on a timely basis and in full, even in the face of dramatic reductions in electricity usage by the relevant Company's customers or dramatic increases of delinquencies and losses on payments from such Company's customers. The True-Up Mechanism represents the most fundamental component of credit enhancement to investors and is a cornerstone of utility securitizations. True-ups are to be incorporated so that securitized surcharges may be adjusted on a periodic basis to correct for any over- or under-collection of nonbypassable securitized surcharges for any reason and to ensure that the expected collection of future securitized surcharges is in accordance with the payment terms of the securitized bonds. True-ups will be made at least semi-annually, throughout the life of the securitized bonds in accordance with the objective of achieving the highest credit ratings per rating agency requirements and investor expectations, except that beginning twelve months prior to the scheduled final payment date for the latest maturing tranche of each series of securitized bonds, the true-up adjustments must be conducted at least quarterly. In addition, I recommend that interim adjustments be authorized to be conducted at any time. The frequency of true-up adjustments throughout the life of the securitized bonds will be described in the final offering document for the transaction and will be consistent with rating agency considerations for achieving the highest credit ratings. It is also important to note that pursuant to the financing order, the True-Up Mechanism provides for cross-collateralization across customer groups. This means that the revenue declines in one customer group will be made up by securitized surcharge adjustments within that customer group, as well as the other customer groups.

It is critical for rating agency purposes that, insofar as public utility commission action is required, true-up adjustments are automatic (for example, the adjustment is not subject to hearing, protest or appeal) and are implemented on an immediate basis subject only to mathematical and clerical error review. The review by the public utility commission of each true-up adjustment is limited in this way because the public utility commission approves the True-Up Mechanism in the financing order. Public utility commissions are typically given between 15 and 30 days to review the requested adjustments for mathematical or clerical error; any required adjustments, if not implemented prior to the end of such review period, are included in the next following true-up adjustment. True- up adjustments will consider ongoing financing costs as well as anticipated debt service requirements, updated electricity usage and customer count forecasts, the then-current Commission-approved customer charge allocation methodologies, in addition to forecasted projections of customer uncollectibles and delinquencies. The True-Up Mechanism shall remain in effect until the securitized bonds and all associated financing costs have been fully paid and any under-collection is recovered from customers and any over-collection is returned to customers.

The capital subaccount at the SPE funded with an amount equal to 0.50 percent of the initial principal amount the securitized bonds will also serve as credit enhancement of the transaction. Also, it is important that the financing order provide for flexibility to include other forms of credit enhancement and other mechanisms (e.g., letters of credit, additional amounts of overcollateralization or reserve accounts, or surety bonds) to improve the marketability of the securitized bonds. None are anticipated but it is important to have such built-in flexibility.

Q. PLEASE EXPAND ON YOUR USE OF THE TERM "NONBYPASSABLE" IN YOUR PREVIOUS ANSWER.

A. The Securitization Statute and financing order provide that securitized surcharges shall be paid by all existing or future retail customers receiving electrical service from the electric utility or its successors or assignees under Commission-approved rate schedules, even if a retail customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in Kentucky. This is another important element of the financing order, both for the rating agency process and for investor considerations.

Q. IN THAT CONTEXT, HOW WOULD THE SECURITIZED SURCHARGE BE AFFECTED IN THE CASE WHERE THE COMPANY IS NO LONGER THE UTILITY IN THE SERVICE AREA?

A. The financing order, upon the issuance of the securitized bonds, creates a binding obligation for the Company, its successors or assignees to collect the securitized surcharge for a servicing fee and allows that obligation to be performed by a replacement servicer appointed by the Trustee, if the relevant servicer does not so perform. Thus, the binding obligation to collect and account for securitized surcharge will survive any adverse event to the servicer. This obligation is binding upon any other entity that provides service in the service territory or any other entity responsible for calculating, billing and collecting the securitized surcharge on the Company's behalf.

Q. PLEASE DISCUSS THE IRREVOCABLE NATURE OF THE FINANCING ORDER.

A. The financing order is irrevocable, and the securitized surcharge is not subject to reduction, alteration or impairment by any further action of the Commission, except for the mathematical and clerical error review as part of the formulaic true-up adjustment process. Thus, so long as the securitized bonds are outstanding, rights and benefits arising from the securitized property created by the financing order may be definitively relied upon by investors and the rating agencies.

Equally important, pursuant to KRS 65.114(2), the Commonwealth [of Kentucky] and its agencies, including the Commission, pledge and agree with bondholders, the owners of the securitized property, and other financing parties that the Commonwealth and its agencies will not take any action listed in KRS 65.114(2) as to any outstanding securitized bonds, the securitized surcharge, or securitized property.

The prohibited actions set forth in KRS 65.114(2) are as follows: (1) altering authorization of the Commission to create an irrevocable contract right or right to sue by the issuance of a financing order creating securitized property, and making the securitized surcharges imposed by a financing order irrevocable, binding, or affecting the nonbypassable charges for all existing and future retail customers of the electric utility; (2) taking or permitting any action that impairs or would impair the value of securitized property or the security for the securitized bonds, or revises the securitized costs for which recovery is authorized; (3) in any way impairing the rights and remedies of the bondholders, assignees, and other financing parties; and (4) except for changes made pursuant to the formula-based true-up mechanism authorized under the Securitization Statute, reducing, altering, or impairing securitized surcharges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed in connection with the related securitized bonds, have been paid and performed in full.

Investors generally perceive that one of the greatest risks to them is that there is a change in law that affects the securitized property, thereby adversely affecting their rights under the Securitization Statute or the financing order. Pursuant to the Securitization Statute, the bondholders, as financing parties to the securitized bonds, will have the full rights and benefits pursuant to KRS 65.114 and 278.670 through 278.696. The Commission's affirmation in the financing order will enhance investor understanding that the risk of an adverse change in law or regulation is remote and will permit counsel to deliver important legal opinions that such adverse changes would not be legally valid.

Q. PLEASE DESCRIBE THE SECTIONS OF THE FINANCING ORDER ENTITLED, "FINDINGS OF FACT," "DISCUSSIONS AND CONCLUSIONS" AND "ORDERING PARAGRAPHS."

A. The Findings of Fact, Discussions and Conclusions, and the Ordering Paragraphs of the financing order constitute the means by which the Commission definitively affirms the conformity of the financing with the applicable provisions of the Securitization Statute. With these findings and conclusions, counsel will have the basis that they need for the highly technical and specialized legal opinions they must issue in connection with the securitization financing, and upon which the rating agencies will rely in assigning the highest possible ratings for the securitized bonds. I emphasize that the provisions of the financing order have been drafted with a view toward providing the basis that counsel will need for these essential opinions. With the structure authorized thereby, the stability of the cash flows securing the securitized bonds will be maximized. The combination of maximized cash flow stability and highest possible ratings will allow the securitized bonds to be structured and priced to meet the requirement that the pricing of the securitized bonds will result in the lowest securitized surcharges consistent with market conditions at the time the securitized bonds are priced under the terms of the financing order.

Q. ARE THERE ANY OTHER KEY ELEMENTS OF THE FINANCING ORDER UPON WHICH YOU WISH TO ELABORATE?

A. Yes. In addition, in the Ordering Paragraphs of the financing order, the Commission recognizes the need for, and affords the Company the flexibility to establish, the final terms and conditions of the securitized bonds. This flexibility will allow the Company to achieve the structure and pricing that will meet the requirements of the Securitization Statute, including the lowest securitized surcharge, consistent with market conditions at the time the securitized bonds are priced under the terms of the financing order and rating agency considerations.

VI. DISCUSSION OF THE SERVICING AGREEMENT

Q. PLEASE DESCRIBE THE CONTENTS AND PURPOSE OF THE SERVICING AGREEMENT.

A. The Servicing Agreement is an agreement among the Company (in its capacity as the servicer of the securitized bonds), the Trustee, and the SPE. The agreement sets forth the responsibilities and obligations of the servicer, including, among other things, calculating, billing and collecting of securitized surcharges, responding to customer inquiries, terminating electric service, filing for true-up adjustments and remitting collections to the Trustee for distribution to bondholders. The Servicing Agreement will prohibit the initial servicer's ability to resign as servicer unless (i) it is unlawful for the initial servicer to continue in such a capacity, or (ii) the Commission consents and the rating agencies confirm the resignation would not impact the ratings on the securitized bonds. Its resignation would not be effective until a replacement servicer has assumed its obligations to continue servicing the securitized bonds without interruption. The servicer may also be terminated from its responsibilities in certain cases upon a majority vote of bondholders, such as the failure to remit collections within a specified period. Any merger or consolidation of the servicer with another entity would require the merged entity to assume the servicer's responsibility under the Servicing Agreement. The terms of the Servicing Agreement are critical to the rating agency analysis of the securitized bonds and the ability to achieve credit ratings in the highest categories. As compensation for its role as initial servicer, the servicer is entitled to earn a servicing fee payable out of securitized surcharge collections. It is important to the rating agencies and the bankruptcy-remote analysis of the transaction that the Company receives an arm's-length fee as servicer of the securitized property, and for its services as Administrator of the SPE. Utility securitizations to date have also required an increase in the servicing fee in the unlikely event the Company is no longer able to perform the servicing role, and a replacement servicer must be brought on board. Rating agencies expect that the Company will be the servicer but assume that a replacement servicer may require additional compensation to perform these services, without access to the Company's existing infrastructure and customer relationships.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I believe the financing order, as proposed, will enable the Company to structure a transaction that can achieve the highest possible ratings, and consistent with investor preferences, will enable the Company to price at the lowest market-clearing interest costs reasonably consistent with investor demand and market conditions at the time of pricing.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does. Thank you.

CASE MIS No.: RP-131823-05
Part III
Administrative, Procedural, and Miscellaneous

26 CFR 601.201: Rulings and determination letters
(Also: §§ 61, 451 and 1001)
Rev. Proc. 2005-61

SECTION 1. PURPOSE

This revenue procedure amplifies Rev. Proc. 2005-3, 2005-1 I.R.B. 118, which sets forth areas of the Internal Revenue Code in which the Internal Revenue Service will not issue advance rulings or determination letters.

SECTION 2. BACKGROUND

.01 Section 3 of Rev. Proc. 2005-3 sets forth a list of those areas of the Internal Revenue Code under the jurisdiction of the Associate Chief Counsel (Corporate), the Associate Chief Counsel (Financial Institutions & Products), the Associate Chief Counsel (Income Tax & Accounting), the Associate Chief Counsel (Passthroughs & 2 Special Industries), the Associate Chief Counsel (Procedure and Administration), and the Division Counsel/Associate Chief Counsel (Tax Exempt and Government Entities) relating to issues on which the Internal Revenue Service will not issue letter rulings or determination letters.
.02 In Rev. Proc. 2005-62, page [INSERT PAGE NUMBER] this Bulletin, the Service provides a safe harbor with respect to the tax treatment of certain cost recovery transactions by regulated investor owned utility companies.

SECTION 3. PROCEDURE

Rev. Proc. 2005-3 is amplified by adding the following to section 3.01: Sections 61, 451 and 1001. Gross Income Defined; General Rule for Taxable Year of Inclusion; Determination of Amount and Recognition of Gain or Loss. Whether, under authorization by an appropriate State agency to recover certain costs pursuant to State specified cost recovery legislation, any investor-owned utility company realizes income upon: (1) the creation of an intangible property right; (2) the transfer of that intangible property right; or (3) the securitization of the intangible property right.

SECTION 4. EFFECT ON OTHER DOCUMENTS

Rev. Proc. 2005-3 is amplified.

SECTION 5. EFFECTIVE DATE

This revenue procedure applies to all ruling requests pending or submitted after [INSERT DATE THIS DOCUMENT IS PUBLISHED IN THE INTERNAL REVENUE BULLETIN].

SECTION 6. DRAFTING INFORMATION

The principal author of this revenue procedure is Thomas M. Preston of the Office of Associate Chief Counsel (Financial Institutions & Products). For further information regarding this revenue procedure contact Mr. Preston at (202) 622-3970 (not a toll free call).

CASE MIS No.: RP-115797-05

Part III

Administrative, Procedural, and Miscellaneous

26 CFR 601.105: Examination of returns and claims for refund, credit, or abatement; determination of correct tax liability.

(Also: Part 1, §§61, 451, 1001)

Rev. Proc. 2005-62

SECTION 1. PURPOSE

This revenue procedure sets forth the manner in which a public utility company may treat the issuance of a financing order by a State agency authorizing the recovery of certain specified costs incurred by the utility and the securitization of the rights created by that financing order.

SECTION 2. BACKGROUND

Revenue Procedure 2002-49, 2002-2 C.B. 172, provides a safe-harbor regarding the treatment of legislatively authorized transactions entered into by investor-owned electric utilities to recover transition costs resulting from the restructuring of the electric utility industry and the institution of a competitive marketplace. Some States enacted legislation to allow the recovery of these transition costs through a nonbypassable surcharge to customers within a utility's historic service area. Utilities continue to operate in wholly or partially regulated environments and maintain exclusive distribution networks for customers in their historic service areas. Rates charged for these operations are determined by local authorities to allow for the recovery of costs and an appropriate return on capital. Some States have enacted legislation that allows utilities to recover certain specified costs through a surcharge based on consumption by customers within the utilities' historic service areas and also authorizes securitization of the surcharge. These statutes are unique to regulated utilities. Accordingly, the tax treatment allowed by this revenue procedure for these transactions is peculiar to this situation. See Revenue Procedure 2005-61, page **[INSERT PAGE NUMBER**], this Bulletin, which adds certain related issues to areas in which rulings or determination letters will not be issued.

SECTION 3. CHANGES

The scope of Revenue Procedure 2002-49 was limited to transition costs that resulted from the deregulation of the generation operations of electric utility companies. This revenue procedure expands the scope of Revenue Procedure 2002-49 to all public utility companies, and costs that are recoverable through a securitization mechanism are not limited to transition costs. Additionally, this revenue procedure eliminates certain requirements in section 4.04(3) of Revenue Procedure 2002-49 relating to level payments and now requires that payments be made on a quarterly or semi-annual basis.

SECTION 4. SCOPE

This revenue procedure applies to investor owned public utility companies that, pursuant to specified cost recovery legislation, receive an irrevocable financing order from an appropriate State agency that determines the amount of certain specified costs the utility will be permitted to recover through qualifying securitization of an intangible property right created by the special legislation.

SECTION 5. DEFINITIONS

01 PUBLIC UTILITY

For purposes of this revenue procedure, the terms “public utility” or “utility” refer to any investor owned utility company (electric or non-electric) that is subject to the regulatory authority of a State public utility commission or other appropriate State agency.

02 SPECIFIED COST RECOVERY LEGISLATION

For purposes of this revenue procedure, specified cost recovery legislation is legislation that—

(1) Is enacted by a State to facilitate the recovery of certain specified costs incurred by a public utility company;

(2) Authorizes the utility to apply for, and authorizes the public utility commission or other appropriate State agency to issue, a financing order determining the amount of specified costs the utility will be allowed to recover;

(3) Provides that pursuant to the financing order, the utility acquires an intangible property right to charge, collect, and receive amounts necessary to provide for the full recovery of the specified costs determined to be recoverable, and assures that the charges are nonbypassable and will be paid by customers within the utility’s historic service territory who receive utility goods or services through the utility’s transmission and distribution system, even if those customers elect to purchase these goods or services from a third party;

(4) Guarantees that neither the State nor any of its agencies has the authority to rescind or amend the financing order, to revise the amount of specified costs, or in any way to reduce or impair the value of the intangible property right, except as may be contemplated by periodic adjustments authorized by the specified cost recovery legislation;

(5) Provides procedures assuring that the sale, assignment, or other transfer of the intangible property right from the utility to a financing entity that is wholly owned, directly or indirectly, by the utility will be perfected under State law as an absolute transfer of the utility’s right, title, and interest in the property; and

(6) Authorizes the securitization of the intangible property right to recover the fixed amount of specified costs through the issuance of bonds, notes, other evidences of indebtedness, or certificates of participation or beneficial interest that are issued

pursuant to an indenture, contract, or other agreement of a utility or a financing entity that is wholly owned, directly or indirectly, by the utility.

03 SPECIFIED COSTS

For purposes of this revenue procedure, specified costs are those costs identified by the State legislature as appropriate for recovery through the securitization mechanism of the specified cost recovery legislation.

04 QUALIFYING SECURITIZATION

For purposes of this revenue procedure, a qualifying securitization is an issuance of any bonds, notes, other evidences of indebtedness, or certificates of participation or beneficial interests that—(1) Is secured by the intangible property right to collect charges for the recovery of specified costs and such other assets, if any, of the financing entity that is wholly owned, directly or indirectly, by the utility; (2) Is issued by a financing entity that is wholly owned, directly or indirectly, by the utility that is initially capitalized by the utility in such a way that equity interests in the financing entity are at least 0.5 percent of the aggregate principal amount of the non-equity instruments issued; and (3) Provides for payments on a quarterly or semi-annual basis.

SECTION 6. APPLICATION

.01 The utility will be treated as not recognizing gross income upon—(1) The receipt of a financing order that creates an intangible property right in the amount of the specified costs that may be recovered through securitization; (2) The receipt of cash or other valuable consideration in exchange for the transfer of that property right to a financing entity that is wholly owned, directly or indirectly, by the utility; or (3) The receipt of cash or other valuable consideration in exchange for securitized instruments issued by the financing entity that is wholly owned, directly or indirectly, by the utility.02 The securitized instruments described in Section 5.04 will be treated as obligations of the utility.03 The nonbypassable charges are gross income to the utility recognized under the utility's usual method of accounting.

SECTION 7. EFFECT ON OTHER DOCUMENTS

This document modifies, amplifies, and supersedes Rev. Proc. 2002-49.

SECTION 8. EFFECTIVE DATE

This revenue procedure is effective [INSERT DATE THIS DOCUMENT IS PUBLISHED IN THE INTERNAL REVENUE BULLETIN.]

SECTION 9. DRAFTING INFORMATION

The principal author of this revenue procedure is Thomas M. Preston of the Office of Associate Chief Counsel (Financial Institutions & Products). For further information regarding this revenue procedure, contact Mr. Preston at (202) 622–3970 (not a toll-free call).

Kentucky Power Company
Case No. 2023-00159

Niehaus Exhibit 2

Class	A-1
WAL (yr)	11.92
Tsy Tenor (yr)	10.00
Tsy Rate as of 6/27/23	3.766%
Balance	$446,700,000
Coupon	5.166%
Tsy Spread	Tsy+140
Prin Window (yr)	0.05-20
Exp Final (yr)	20.00

Year	Date	Balance	Principal	Interest	Total P&I
0.0	1/1/2024	446,700,000			
0.5	7/1/2024	440,193,784	6,506,216	11,538,261.00	18,044,477
1.0	1/1/2025	433,519,513	6,674,271	11,370,205.44	18,044,477
1.5	7/1/2025	426,672,845	6,846,668	11,197,809.01	18,044,477
2.0	1/1/2026	419,649,328	7,023,517	11,020,959.58	18,044,477
2.5	7/1/2026	*412,444,393*	7,204,935	10,839,542.13	18,044,477
3.0	1/1/2027	405,053,355	7,391,038	10,653,438.67	18,044,477
3.5	7/1/2027	397,471,406	7,581,949	10,462,528.15	18,044,477
4.0	1/1/2028	389,693,616	7,777,790	10,266,686.42	18,044,477
4.5	7/1/2028	381,714,925	7,978,691	10,065,786.09	18,044,477
5.0	1/1/2029	373,530,144	8,184,780	9,859,696.51	18,044,477
5.5	7/1/2029	365,133,951	8,396,193	9,648,283.63	18,044,477
6.0	1/1/2030	356,520,884	8,613,067	9,431,409.96	18,044,477
6.5	7/1/2030	347,685,342	8,835,542	9,208,934.44	18,044,477
7.0	1/1/2031	338,621,577	9,063,764	8,980,712.38	18,044,477
7.5	7/1/2031	329,323,696	9,297,882	8,746,595.34	18,044,477
8.0	1/1/2032	319,785,650	9,538,046	8,506,431.06	18,044,477
8.5	7/1/2032	310,001,236	9,784,414	8,260,063.34	18,044,477
9.0	1/1/2033	299,964,092	10,037,145	8,007,331.94	18,044,477
9.5	7/1/2033	289,667,687	10,296,404	7,748,072.49	18,044,477
10.0	1/1/2034	279,105,327	10,562,361	7,482,116.36	18,044,477
10.5	7/1/2034	268,270,140	10,835,186	7,209,290.59	18,044,477
11.0	1/1/2035	257,155,081	11,115,059	6,929,417.73	18,044,477
11.5	7/1/2035	245,752,920	11,402,161	6,642,315.75	18,044,477
12.0	1/1/2036	234,056,241	11,696,679	6,347,797.93	18,044,477
12.5	7/1/2036	222,057,437	11,998,804	6,045,672.71	18,044,477
13.0	1/1/2037	209,748,704	12,308,733	5,735,743.60	18,044,477
13.5	7/1/2037	197,122,036	12,626,668	5,417,809.02	18,044,477
14.0	1/1/2038	184,169,221	12,952,815	5,091,662.19	18,044,477
14.5	7/1/2038	170,881,835	13,287,386	4,757,090.99	18,044,477
15.0	1/1/2039	157,251,236	13,630,599	4,413,877.81	18,044,477
15.5	7/1/2039	143,268,559	13,982,677	4,061,799.44	18,044,477
16.0	1/1/2040	128,924,709	14,343,850	3,700,626.88	18,044,477
16.5	7/1/2040	114,210,357	14,714,352	3,330,125.23	18,044,477
17.0	1/1/2041	99,115,934	15,094,423	2,950,053.53	18,044,477
17.5	7/1/2041	83,631,622	15,484,312	2,560,164.58	18,044,477
18.0	1/1/2042	67,747,350	15,884,272	2,160,204.79	18,044,477
18.5	7/1/2042	51,452,787	16,294,563	1,749,914.04	18,044,477
19.0	1/1/2043	34,737,335	16,715,451	1,329,025.48	18,044,477
19.5	7/1/2043	17,590,124	17,147,211	897,265.37	18,044,477
20.0	1/1/2044	-	17,590,124	454,352.90	18,044,477

Notes:

(1) Structure is preliminary and subject to change based on market conditions and rating agency requirements at the time of pricing.
(2) Structure is based in part upon information supplied by the Company, which is believed to be reliable but has not been verified. No representation or warranty is being made relating to this structure. Estimates of future performance are based on assumptions that may not be realized. Actual events may differ from those assumed and changes to any assumptions may have a material impact on any projections or estimates. Other events not taken into account may occur and may significantly affect the projections or estimates. Certain assumptions may have been made for modeling purposes only to simplify the presentation and/or calculation of any projections or estimates. No assurance can be given that any such assumptions will reflect actual future events. Totals may not foot due to rounding.
(3) Assumes "AAA(sf)" ratings by S&P and Moody's.
(4) Benchmark 10 year treasury rate of 3.766% as of June 27, 2023.

Kentucky Power Company
Case No. 2023-00159

Niehaus Exhibit 3

#	Sponsor/Issuer	Deal Amount ($)	Pricing Date
1	Southern Indiana Gas and Electric Company	$341,450,000	6/21/2023
2	Atmos Energy Kansas Securitization I, LLC	$95,000,000	6/9/2023
3	Edison International	$775,000,000	4/19/2023
4	Louisiana Utilities Restoration Corporation Project/ELL (Entergy Corp)	$1,491,000,000	3/21/2023
5	Texas Natural Gas Securitization Finance Corporation	3,536,310,000	3/9/2023
6	Entergy Corp	209,000,000	12/9/2022
7	Brazos Electric Power Cooperative	713,000,000	12/8/2022
8	Denton County Electric Cooperative Inc (CoServ)	460,000,000	12/7/2022
9	United Electric Cooperative Inc (UEC)	452,000,000	12/6/2022
10	Pacific Gas & Electric	983,000,000	11/18/2022
11	One Gas	336,000,000	11/9/2022
12	Long Island Power Authority	882,070,000	9/20/2022
13	Oklahoma Development Finance Authority (Public Service Company of Oklahoma)	697,000,000	8/30/2022
14	Oklahoma Development Finance Authority (One Gas)	1,354,000,000	8/18/2022
15	Pacific Gas & Electric	3,900,000,000	7/13/2022
16	Oklahoma Development Finance Authority (OGE Energy Corp)	762,000,000	7/8/2022
17	Cleco Partners LP	452,000,000	6/9/2022
18	Electric Reliability Council of Texas (ERCOT)	2,116,000,000	6/8/2022
19	Louisiana Utilities Restoration Corporation Project/ELL (Entergy Corp)	3,194,000,000	5/11/2022
20	Pacific Gas & Electric	3,600,000,000	5/3/2022
21	Entergy Corp	291,000,000	3/24/2022
22	DTE Energy Co	236,000,000	3/11/2022
23	Edison International	533,000,000	2/8/2022
24	Rayburn Electric Cooperative	908,000,000	2/4/2022
25	Duke Energy Carolinas	770,000,000	11/17/2021
26	Duke Energy Progress	237,000,000	11/17/2021
27	Pacific Gas & Electric	860,000,000	11/4/2021
28	WEC Energy Group	119,000,000	5/4/2021
29	Southern California Edison	338,000,000	2/17/2021
30	AEP Texas Restoration Funding LLC	235,282,000	9/11/2019
31	Public Service New Hampshire Funding LLC.	635,663,200	5/1/2018
32	Duke Energy Florida Project Finance LLC	1,294,290,000	6/15/2016
33	Entergy New Orleans Storm Recovery Funding I	98,730,000	7/14/2015
34	Dept. of Business, Economic Development, and Tourism / Hawaii Electric	150,000,000	11/13/2014

#	Sponsor/Issuer	Deal Amount ($)	Pricing Date
35	Louisiana Utilities Restoration Corporation Project/ELL	243,850,000	7/29/2014
36	Louisiana Local Government System Restoration/EGSL	71,000,000	7/29/2014
37	Consumers 2014 Securitization Funding LLC	378,000,000	7/14/2014
38	Appalachian Consumer Rate Relief Funding LLC	380,300,000	11/6/2013
39	Ohio Phase-In-Recovery Funding LLC	267,408,000	7/23/2013
40	FirstEnergy Ohio PIRB Special Purpose Trust	444,922,000	6/12/2013
41	AEP Texas Central Funding III	800,000,000	3/7/2012
42	Centerpoint Energy Transmission Bond Co. IV	1,695,000,000	1/11/2012
43	Entergy Louisiana Investment Recovery Funding I, LLC	207,156,000	9/15/2011
44	Entergy Arkansas Energy Restoration Funding LLC	124,100,000	8/11/2010
45	Louisiana Utilities Restoration Corporation Project/ELL	468,900,000	7/15/2010
46	Louisiana Utilities Restoration Corporation Project/EGSL	244,100,000	7/15/2010
47	MP Environmental Funding LLC	64,380,000	12/16/2009
48	PE Environmental Funding LLC	21,510,000	12/16/2009
49	CenterPoint Energy Restoration Bond	664,859,000	11/18/2009
50	Entergy Texas Restoration Funding	545,900,000	10/29/2009
51	Louisiana Public Facilities Authority	278,400,000	8/20/2008
52	Louisiana Public Facilities Authority	687,700,000	7/22/2008
53	Cleco Katrina/Rita Hurricane Recovery Funding LLC 2008	180,600,000	2/28/2008
54	CenterPoint Energy Transition Bond Company III	488,472,000	1/29/2008
55	Entergy Gulf States Reconstruction Funding I, LLC	329,500,000	6/22/2007
56	RSB BondCo LLC (BG&E sponsor)	623,200,000	6/22/2007
57	FPL Recovery Funding LLC	652,000,000	5/15/2007
58	MP Environmental Funding LLC	344,475,000	4/3/2007
59	PE Environmental Funding, LLC	114,825,000	4/3/2007
60	AEP Texas Central Transition Funding II	1,739,700,000	10/4/2006
61	JCP&L Transition Funding II	182,400,000	8/4/2006
62	Centerpoint Energy Series A	1,851,000,000	12/9/2005
63	PG&E Energy Recovery Funding LLC Series 2005-2	844,461,000	11/3/2005
64	West Penn Power	115,000,000	9/22/2005
65	PSE&G 2005-1	102,700,000	9/9/2005
66	Massachusetts RRB Special Purpose Trust 2005-1	674,500,000	2/15/2005
67	PG&E Energy Recovery Funding LLC Series 2005-1	1,887,864,000	2/3/2005
68	Rockland Electric Company	46,300,000	7/28/2004

#	Sponsor/Issuer	Deal Amount ($)	Pricing Date
69	Oncor (TXU) 2004-1	789,777,000	5/28/2004
70	Atlantic City Electric	152,000,000	12/18/2003
71	Oncor 2003-1	500,000,000	8/14/2003
72	Atlantic City Electric	440,000,000	12/11/2002
73	JCP&L Transition Funding LLC	320,000,000	6/4/2002
74	CPL Transition Funding LLC	797,334,897	1/31/2002
75	PSNH Funding LLC 2	50,000,000	1/16/2002
76	Consumers Funding LLC	468,592,000	10/31/2001
77	CenterPoint Energy Transition Bond Company I	748,987,000	10/17/2001
78	Western Mass Electric	155,000,000	5/14/2001
79	PSNH Funding LLC	525,000,000	4/20/2001
80	CL&P Funding LLC	1,438,400,000	3/27/2001
81	Detroit Edison 2001-1	1,750,000,000	3/2/2001
82	PECO 2001-A	805,500,000	2/15/2001
83	PSE&G 2001-A	2,525,000,000	1/25/2001
84	PECO 2000-A	1,000,000,000	4/27/2000
85	West Penn Power	600,000,000	11/3/1999
86	Pennsylvania Power & Light	2,420,000,000	7/29/1999
87	Boston Edison	725,000,000	7/27/1999
88	Sierra Pacific Power	24,000,000	4/8/1999
89	PECO Energy	4,000,100,000	3/18/1999
90	Montana Power	64,000,000	12/22/1998
91	Illinois Power	864,000,000	12/10/1998
92	Commonwealth Edison	3,400,000,000	12/7/1998
93	San Diego Gas & Electric	657,900,000	12/4/1997
94	Southern California Edison	2,463,000,000	12/4/1997
95	Pacific Gas & Electric	2,901,000,000	11/25/1997
Total		**$81,403,868,097**	

KATRINA T NIEUHAUS

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New York, New York 10282
Email: katrina.niehaus@gs.com Cell: 917-277-1414

GOLDMAN SACHS & CO. LLC **2005 - Present**

Co-Head of Corporate Structured Finance Group

- Managing Director in the Structured Finance business within Investment Banking and the Co-Head of Goldman Sachs' Corporate Structured Finance Group
- Extensive experience structuring and executing transactions in a broad array of asset classes
  - Utility Securitization – Has been involved in GS' utility securitization effort since joining the firm in 2005 and has structured, distributed and testified as a utility company expert witness for regulatory commissions in multiple states (see next page for full list of transaction experience)
  - Intellectual Property – Managed sale and financing of numerous types of intellectual property including restaurant royalties, pharmaceutical royalties, technology royalties, naming rights, and fashion brand related royalties
  - New Infrastructure –
    - Data Centers: Structured and distributed securitizations backed by single assets as well as diversified portfolios in both private 4(a)(2) and 144A form across multiple transactions
    - Distribution Centers: Structured and distributed senior securitization notes backed by Amazon distribution centers and related long term leases for multiple asset aggregators
    - Commercial & Industrial Solar: Advised and provided warehouse financing directly to C&I asset originators as well as hedge funds investing in C&I assets
  - Consumer Credit –
    - Residential Solar Loans: Purchased over $1,000 mm of solar loans directly from LoanPal and Solar Mosaic with risk ultimately distributed to capital markets in form of ABS and residual interests
    - Residential Solar Leases / PPAs: Lead the structuring, issuance, and distribution of warehouses and term securitizations for multiple sponsors
    - Home Improvement Loans: Negotiated warehouse loans and loan purchase agreements for private loan originators
- Municipal Finance – Structured transactions for a number of municipalities including Ontario Power Group, The Long Island Power Authority, and The State of Hawaii using novel technology (charges on customers power bills) to reduce cost of capital and impact of debt on U.S. and international municipal entities balance sheet
- Federal Government – Raised over $23bn in 38 transactions for U.S. Small Business Administration (subsidiary of the U.S. Department of the Treasury)
- Other Esoteric ABS Experience – Whole Business Securitization, Rental Car, Specialty Lending, Parking, Life Settlement, Insurance Premium Finance

LEHMAN BROTHERS INC. **2004 - 2005**

Analyst, Structured Finance Group, Investment Banking Division

PRIOR UTILITY SECURITIZATION EXPERIENCE:

Transaction	Issuance Date	Issuer	Issuance Amount ($mm)	State / Province	Commission / State Advisors	UW Role	Structured Transaction	GS Testimony[1]
LCDA 2022-ENO	Dec-22	Entergy Louisiana	$209	Louisiana	–	–	✓	✓
COSERV 2022	Dec-22	Denton County Electric Cooperative (CoServ Electric)	$460	Texas	–	Sole Bookrunner	✓	NA
LIPA 2022	Sept-22	Long Island Power Authority, NY	$935	New York	Public Financial Management	Lead Left Bookrunner	✓	NA
PGE 2022-A	Nov-22	PG&E (AB1054)	$983	California	Ducera	Structuring Agent	✓	✓
ODFA (ONG)	Aug-22	Oklahoma Natural Gas	$1,354	Oklahoma	Hilltop Securities	Joint Lead Bookrunner	✓	NA
PGE 2022-B	Jul-2022	PG&E (SB901)	$3,900	California	Ducera	Joint Lead Bookrunner	–	–
LCDA 2022-ELL	May-22	Entergy Louisiana	$3,194	Louisiana	–	–	✓	✓
PGE 2022-A	May-22	PG&E (SB901)	$3,600	California	Ducera	Joint Lead Bookrunner	–	–
ETR 2022-A	Mar-22	Entergy Texas	$291	Texas	Drexel Hamilton	Lead Bookrunner	✓	✓
PCG 2021-A	Nov-21	PG&E (AB1054)	$861	California	Ducera	Lead Bookrunner	✓	✓
ENOLA 2021-A	Feb-21	Entergy New Orleans	$155	Louisiana	–	–	✓	✓
AEPTC 2019-1	Sep-19	AEP Texas Central	$235	Texas	Drexel Hamilton (Pricing Only)	Lead Bookrunner	✓	✓
PSNH 2018-1	May-18	Public Service Company of New Hampshire	$636	New Hampshire	None	Lead Bookrunner	✓	✓
FHT 2018-2	Apr-18	Ontario Power Generation	$400	Ontario	None	Joint Lead Bookrunner	✓	NA
FHT 2018-1	Feb-18	Ontario Power Generation	$500	Ontario	None	Joint Lead Bookrunner	✓	NA
UDSA 2017	Nov-17	Long Island Power Authority	$370	New York	None	Senior co-manager	–	–
UDSA 2016B	Sep-16	Long Island Power Authority	$469	New York	None	Senior co-manager	–	–
UDSA 2016A	Apr-16	Long Island Power Authority	$637	New York	None	Senior co-manager	–	–
UDSA 2015	Oct-15	Long Island Power Authority	$1,002	New York	None	Senior co-manager	–	–
HGEMS 2014	Nov-14	State of Hawaii	$150	Hawaii	First Southwest (State) Public Financial Management (PUC)	Sole Bookrunner	✓	NA
UDSA 2013	Dec-13	Long Island Power Authority	$1,539	New York	Public Financial Management	Lead Bookrunner	✓	NA

FEOH 2013	Jun-13	FirstEnergy Ohio	$445	Ohio	First Southwest	Lead Bookrunner	✓	NA
CNP 2009	Nov-09	CenterPoint Houston	$665	Texas	First Southwest	Lead Bookrunner	✓	✓
ETR 2009	Nov-09	Entergy Texas	$546	Texas	First Southwest	Co-Manager	–	–
JCPL 2006	Aug-06	Jersey Central Power & Light	$182	New Jersey	–	Lead Structuring Agent	✓	✓
CNP 2005	Dec-05	CenterPoint Energy	$1,851	Texas	Saber Partners	Co-Manager	–	–
NSTAR 2005	Feb-05	NSTAR	$675	Massachusetts	–	Lead Advisor	✓	NA

[1] *Recently, certain jurisdictions like Hawaii, Ohio and New York did not require banker testimony. Katrina was involved in preparation of all testimony filed by GS as outlined. Testimony filed prior to 2013 was done in the name of Curtis Probst.*

<u>OTHER:</u>

SEABURY HALL **2020-Present**

Board of Trustees

<u>EDUCATION:</u>

THE SCHOOL OF INTERNATIONAL AND PUBLIC AFFAIRS AT COLUMBIA UNIVERSITY IN THE CITY OF NEW YORK
Master of Public Administration **2018**

THE WHARTON SCHOOL OF THE UNIVERSITY OF PENNSYLVANIA
Bachelor of Science in Economics **2004**

VERIFICATION

The undersigned, Katrina T. Niehaus, being duly sworn, deposes and says she is the Managing Director, Head of Corporate Asset Backed Securities Finance Group, for Goldman, Sachs and Company, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Katrina T. Niehaus

State of New York)
) Case No. 2023-00159
County of New York)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Katrina T. Niehaus, on June 28, 2023.

Notary Public

Catherine A Sullivan
NOTARY PUBLIC, STATE OF NEW YORK
Registration No. 01SU6438672
Qualified in New York County
Commission Expires August 22, 2026

My Commission Expires 8/22/2026

Notary ID Number 01SU6438672

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

MICHAEL M. SPAETH

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
MICHAEL M. SPAETH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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EXHIBITS

DIRECT TESTIMONY OF
MICHAEL M. SPAETH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Michael M. Spaeth, and I am employed by American Electric Power Service Corporation ("AEPSC") as a Regulatory Pricing & Analysis Manager. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I graduated from The Ohio State University with a Bachelor of Science degree in City & Regional Planning. In 2013, I accepted a position at AEPSC in Regulated Pricing and Analysis, where my responsibilities included preparation of cost-of-service studies, rate design and tariff provisions for the AEP operating companies. In 2017, I accepted a position with NiSource Inc., a regulated natural gas and electric utility, as a Project Analyst – Planning, where I was responsible for regulatory case management in support of long and short-term natural gas forecasting plans, reporting to various state and federal regulatory commissions, and the calculation of rates. In 2019, I returned to AEPSC as a Regulatory Consultant Senior, where my responsibilities include preparation of cost-of-service studies, rate design and tariff provisions for the AEP operating companies. I was promoted to my current position in 2022.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include the oversight of cost of service analyses, rate design, and special contracts for the AEP System operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I have presented testimony on behalf of AEP operating companies before the Virginia and Indiana state regulatory commissions.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to:

(1) to provide an overview of how the Company's base rates relate to the various surcharges and riders it utilizes;

(2) to describe the Company's proposed rate design, including the changes to the residential service charge, and the proposal to include a residential optional seasonal provision;

(3) to describe certain changes to the Company's tariffs, including (i); the Federal Tax Cut ("FTC") tariff, (ii); the Company's proposal for tariff Distribution Reliability Rider ("DRR"), as well as the cost allocation and rate design for the projects for inclusion in that rider, (iii) the Company's proposal for tariff Securitization Financing Rider ("SFR"); and

(4) to support the marginal cost of service analysis related to the test year operation of the Company's Economic Development Rider and Special Contract.

Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Description
EXHIBIT MMS-1	Base Rate Revenue Target Summary & Rate Design
EXHIBIT MMS-2	Redline Federal Tax Cut Tariff
EXHIBIT MMS-3	Proposed Distribution Reliability Rider Tariff

EXHIBIT MMS-4	Proposed Securitization Financing Rider Tariff
EXHIBIT MMS-5	Securitization Financing Rider Revenue Requirement and Rate Design
EXHIBIT MMS-6	Economic Development Rider Customer Analysis
EXHIBIT MMS-7	Special Contract Analysis

Additionally, I support Section II Exhibits I, J and K of the Company's standard filing requirements.

IV. BASE RATE COST OF SERVICE OVERVIEW

Q. CAN YOU DESCRIBE GENERALLY THE MECHANISMS THROUGH WHICH KENTUCKY POWER CHARGES ITS CUSTOMERS FOR THE ELECTRIC SERVICE IT PROVIDES?

A. Yes. Kentucky Power charges its customers for electric service through two types of mechanisms: (1) base rates; and (2) surcharges and riders. Through base rates, the Company recovers its operating expenses and a return on and of the capital investments it has prudently made to provide safe and reliable electric service to its customers. The Company also recovers through surcharges and riders certain costs that are volatile or otherwise better suited for recovery through mechanisms other than base rates.

Q. HOW DOES THE INTERRELATION BETWEEN BASE RATES AND THE COMPANY'S SURCHARGES AFFECT THE COST OF SERVICE STUDY PERFORMED IN THIS CASE?

A. Kentucky Power's test year revenues and operating expenses included revenues and expenses relating to a number of surcharges and riders.

To properly determine the portion of the cost of service to be recovered through base rates, the Company had to address the revenues and expenses associated with each surcharge. How each surcharge is addressed depends on the manner in which the surcharge operates.

Q. ARE THERE ANY SURCHARGES WHOSE REVENUES AND EXPENSES ARE FULLY REMOVED FROM BASE RATES?

A. Yes. The Company removed all revenues and expenses associated with the following surcharges from base rates:

- Decommissioning Rider
- Demand-Side Management ("DSM") Adjustment Clause
- Capacity Charge
- Residential Energy Assistance
- Kentucky Economic Development Surcharge ("KEDS")
- Purchased Power Adjustment ("PPA")
- Federal Tax Cut Tariff ("FTC")
- System Sales Clause ("SSC")
- Fuel Adjustment Clause
- Environmental Surcharge (Mitchell FGD portion)

Each of these surcharges recovers specifically-identified costs that are separate from the Company's base rate requirements.

- <u>Decommissioning Rider</u> – through the Decommissioning Rider, the Company recovers the remaining net book value of the retired Big Sandy Unit 2 and the incurred decommissioning costs for coal-related assets at the Big Sandy plant.
- <u>DSM Adjustment Clause</u> – through the DSM Adjustment Clause, the Company recovers the program costs and lost revenues associated with the Company's demand side management and energy efficiency program.
- <u>Capacity Charge</u> – through the Capacity Charge, the Company recovered $6.2 million annually through December 8, 2022, as approved by the Commission's final Order in Case No. 2004-00420.

- Residential Energy Assistance – the Residential Energy Assistance surcharge is a fixed charge levied on each residential account and matched on a dollar-for-dollar basis by the Company to provide financial assistance to low-income residential customers.
- Kentucky Economic Development Surcharge – The KEDS is a fixed charge levied on each account, and matched on a dollar-for-dollar basis by the Company, to support economic development in the Company's service territory.
- Purchased Power Adjustment – The PPA collects certain purchase power costs not recoverable through the fuel adjustment clause; CS-IRP, DRS, and VCS credits paid to interruptible customers; incremental PJM Load Serving Entity ("LSE") Open Access Transmission Tariff ("OATT") expense net of the transmission return difference; and costs associated with certain previously-approved Rockport-related items.
- Fuel Adjustment Clause – This mechanism collects from or credits to customers the difference between actual fuel costs and the $.02612 $/kWh embedded in base energy rates for fuel on a monthly basis.
- System Sales Clause – The SSC is the Company's tracking mechanism for off system sales margins achieved versus the credit amount embedded in base rates. The test year SSC retail revenues and deferral were removed from the proposed base rate cost of service; adjusted off system sales margins were included in the base rate cost of service as Company Witness Walsh discusses in her testimony.
- Environmental Surcharge (Mitchell FGD Portion) – Generally, test year environmental surcharge costs are included in base rates as part of a base rate cost of service. In accordance with the Commission-approved settlement agreement in Case No. 2012-

00578, the cost of service associated with the Mitchell plant flue gas desulfurization ("FGD") (scrubber) remains in the Environmental Surcharge for recovery purposes.

- Federal Tax Cut Tariff – This rider provides a rate credit to customers related to the amortization of excess accumulated deferred federal income taxes ("ADFIT") related to the Tax Cuts and Jobs Act of 2017.

Q. CONVERSELY, ARE THERE ANY SURCHARGES WHOSE REVENUES AND EXPENSES ARE INCLUDED IN BASE RATES?

A. Yes. The Company included the revenues and expenses associated with the non-Mitchell FGD portion of the test year Environmental Surcharge in its proposed base rate cost of service. In addition, the Company is proposing to include the adjusted test year level of OATT costs in base rate cost of service, as discussed by Company Witness West.

Q. WHY WERE A PORTION OF THE ENVIRONMENTAL SURCHARGE REVENUES INCLUDED IN BASE RATES?

A. The Company incurred costs during the test year associated with projects included in the Company's approved environmental compliance plan. Through the Environmental Surcharge, the Company recovers from or credits to customers the costs of its environmental projects that exceed or are below the corresponding monthly amounts included in base rates. The Company's test year non- Mitchell FGD environmental compliance costs and non-Mitchell FGD environmental surcharge revenues are included in base rates and serve as the monthly baselines against which actual costs are compared.

Q. ARE ALL OF THE TEST YEAR ENVIRONMENTAL COMPLIANCE COSTS INCLUDED IN BASE RATES?

A. No. As noted above, Mitchell FGD costs are recovered exclusively through the environmental surcharge (as opposed to just the variance from the prior year's costs).

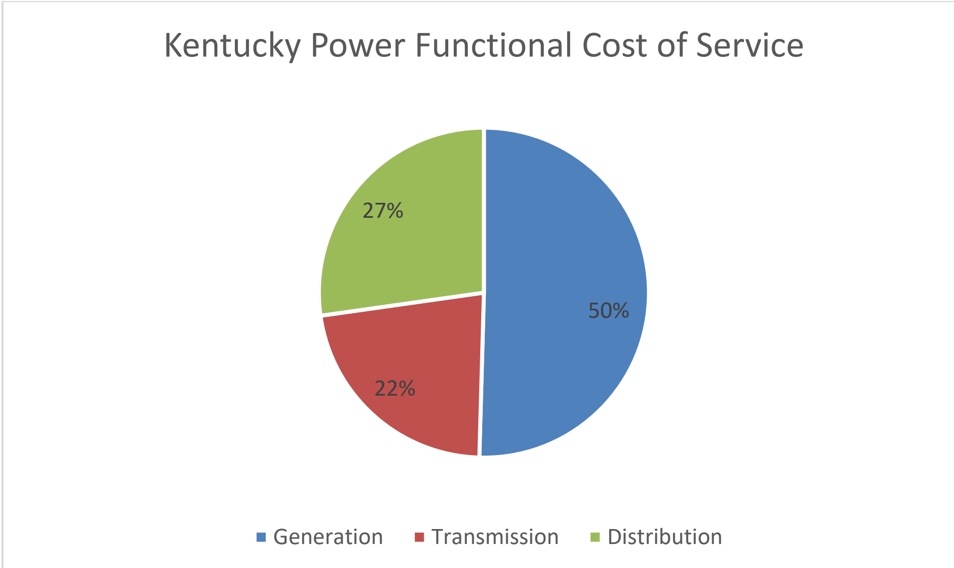
Q. WHY DOES THE COMPANY INCLUDE OFF SYSTEM SALES MARGINS FROM THE SYSTEM SALES CLAUSE IN BASE RATES?

A. Through the SSC, the Company shares with customers the difference between the embedded base rate credit for off system sales margins and the actual off system sales margins realized. The Company included an adjusted level of off system sales margins in the base rate cost of service because the Company is proposing to reset the embedded base rate credit to exclude Rockport's contribution to off system sales margins since the Rockport Unit Power Agreement expired. Company Witness Walsh's Direct Testimony further discusses the adjustments to off system sales margins.

Q. PLEASE PROVIDE A BRIEF SUMMARY REGARDING THE COMPONENTS OF THE COMPANY'S BASE RATE COST OF SERVICE AND GENERALLY WHICH CUSTOMERS ARE RESPONSIBLE FOR THOSE COSTS.

A. The Company's Kentucky retail jurisdictional cost of service consists of the basic functions of generation, transmission and distribution service as follows:

Figure MMS-1



The generation function comprises the majority of customers' cost of service. Both the generation and transmission functions are utilized by all customers and included in all customers' rates. Unlike generation and transmission costs, distribution costs are only included in the rates of distribution voltage level customers, except for a small amount primarily related to metering and billing. Approximately 37% of the Company's adjusted test year usage (and associated billing units) was for customers taking service at voltage levels above distribution. Therefore, roughly a quarter of the Company's cost of service is paid by distribution level customers that make up about two thirds of adjusted test year billing units.

V. RATE DESIGN

Q. IS THE COMPANY PROPOSING TO ELIMINATE ANY OF THE CURRENT INTER-CLASS SUBSIDY IN THIS CASE?

A. No, it is not. The Company's analysis showed that the residential class percentage increase was already above the average percentage increase with the existing subsidies in place.

Kentucky Power elected not to propose an even higher residential increase by proposing to remove some level of existing subsidies at this time given current circumstances. The residential class is currently receiving a $31.9 million subsidy being paid by the other customer classes.[1] If the Commission were to approve a lower base rate revenue increase than the Company has requested in this case, the Company would be in favor of removing as much of the existing inter-class subsidy as reasonable. Although the Company decided not to propose reducing the existing inter-class subsidies, cost-based rates continue to be the Company's goal.

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE COMPANY'S PROPOSED RATES.

A. The Company's underlying approach in designing rates is to design its rates and rate components so that they reflect the Company's costs to provide service to each of its customer classes. This approach includes collecting basic service-related costs through basic service charges and recognizing the differences in the costs to serve customers at different service delivery voltages.

The rate design process involved multiple steps that varied with each tariff. The cost components developed by Company Witness Cost in the class cost of service study informed the relative amounts of revenue that should be recovered from service charges, energy charges and demand charges. In general, where sufficient metering data was available for a customer class, the Company designed full-cost service charges, energy rates, and demand rates by dividing the component-allocated proposed revenues by the test year billing units. These initial rates were then compared to the current rates to determine

[1] Current inter-class subsidies can be found in Company Witness Cost's Exhibit JNC-2.

whether the Company needed to moderate the full-cost price changes to mitigate rate impacts on groups of customers. The proposed base rate revenue targets and rate design workpapers are included as Exhibit MMS-1.

Q. FOR WHICH TARIFFS IS THE COMPANY PROPOSING BASE RATE DESIGN CHANGES IN THIS PROCEEDING?

A. The Company is not proposing any major changes to the design of its existing rates in this proceeding.

i. <u>Residential Service Rate Design</u>

Q. WHAT CHANGES TO THE RESIDENTIAL SERVICE RATE DESIGN IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing to increase the basic service charge to $20.00 per month from $17.50 and to add an optional seasonal rate provision to aid the Company's customers who utilize electricity to heat their homes.

Q. WHAT IS THE RATIONALE FOR INCREASING THE RESIDENTIAL BASIC SERVICE CHARGE?

A. The Company is proposing to increase the basic service charge for residential customers to more accurately reflect the actual fixed cost of providing service to those customers. The full cost residential customer charge is nearly $51 per month. The rate structures for customer classes that employ demand charges are better aligned with cost causation principles than those that do not because fixed costs are generally recovered through a demand charge. Because the residential class does not include a separate demand charge, the majority of fixed distribution costs are recovered through the energy charge. These fixed distribution costs, or at least a larger portion of them, should be recovered in the basic service charge since they do not vary with usage and are instead solely the costs associated with connecting a customer to the distribution system and maintaining that connection. The current basic service charge is too low relative to the fixed cost of providing electric service creating intra-class subsidies between residential customers. Because of these intra-class subsidies, the current basic service charge disadvantages higher usage customers, including electric heating and lower income customers.

Q. DID THE BASIC SERVICE CHARGE INCREASE GRANTED IN THE COMPANY'S LAST RATE CASE ELIMINATE THE INTRA-CLASS SUBSIDY?

A. No. The basic service charge increase in the last rate case from $14 to $17.50 per month helped to reduce the intra-class subsidy being paid by higher use customers but did not eliminate it. As can be seen on Exhibit MMS-1, the total proposed base rate revenue target for the residential class is $283.9 million of which the energy portion is $70.2 million. The $213.7 million balance is comprised of demand and customer related costs that are commonly referred to as "fixed costs" as they do not vary with kWh usage levels.

However, the current residential base rate design only recovers $27.6 million (1,579,320 bills x $17.50 service charge) of fixed costs from non-kWh charges with the other $213.7 million of fixed costs being collected through kWh rates and thus creating the large intra-class subsidy being paid by above average users like electric heating and lower income customers to below average users. The proposed $2.50 increase in the basic service charge will reduce the existing intra-class subsidy by shifting $3.9 million to a fixed recovery (1,579,320 bills x $2.50), which is a reasonable and gradual step in the right direction.

Q. PLEASE DESCRIBE THE PROPOSED RESIDENTIAL OPTIONAL SEASONAL PROVISION.

A. To provide winter bill relief and reduce monthly bill volatility for the Company's electric heating and lower income customers the Company is proposing an optional seasonal provision for residential customers. The optional seasonal provision offers a winter (December through March) rate of 0.11947 $/kWh and an all other months rate of 0.13762 $/kWh. The proposed standard residential rate is 0.12947 $/kWh so customers who enroll in the optional seasonal provision would reduce their winter season bills by 0.01000 $/kWh, or $14.17 per month for a typical 1,418 kWh electric heating customer.

Figure MMS-2

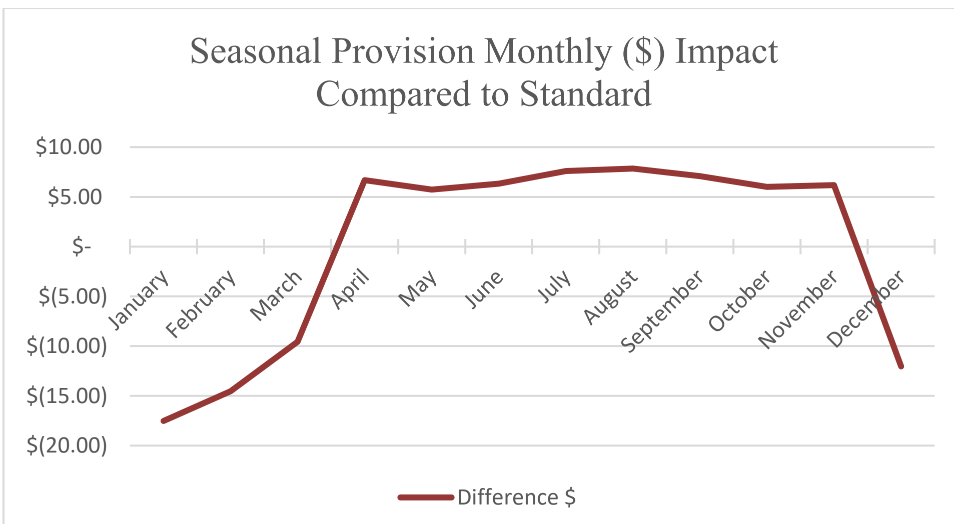


Figure MMS-2 provides an example of the residential bill impact associated with participating in the optional seasonal provision. The differential between the rates by season is a cost-based design that recovers all fixed distribution costs not being recovered through the customer charge on a uniform basis between the seasons. In other words, a customer would pay on average the same amount for distribution costs during winter months and all other months. Generation and transmission costs remain a uniform per kWh charge across all months in the same manner as the standard residential rate.

The optional seasonal provision is open to any residential customer to enroll for a minimum period of 12 consecutive months.

Q. WILL THE INCREASED BASIC SERVICE CHARGE ALSO IMPACT MONTHLY BILL VOLATILITY?

A. Yes. Because less of the fixed costs will be recovered through the usage-related energy charge, the average customer will experience less bill volatility in high usage months. This is especially true for the Company's electric heating customers, who tend to experience very high usage months in the winter to heat their homes. This proposed rate design change will also lessen the bill impact in winter months because the increased usage will not result in even greater subsidization of lower usage customers. Further, as described above, this is an appropriate result based upon cost causation principles.

Q. WHAT IMPACT WOULD THE HIGHER BASIC SERVICE CHARGE HAVE ON LOWER INCOME AND ELECTRIC HEATING CUSTOMERS?

A. Recovering more fixed costs through the basic service charge rather than an energy charge benefits lower income customers who, because they often do not have the resources to invest in weatherization and energy efficient appliances, have higher than average usage. Based on test year data, the average kWh usage for the Company's low income energy assistance customers (approximately 1,300 kWh/month) is greater than the average usage for the residential class as a whole (approximately 1,240 kWh/month). Because the increased service charge benefits higher usage customers by reducing intra-class subsidies, the change will benefit the average low income customer relative to other residential customers.

The Company's electric heating customers will also benefit from the increased service charge because their average usage (1,418 kWh/month) is also above the residential class average. During the test year, 68% of the Company's low income energy assistance customers were also electric heating customers.

Q. HOW WAS THE NEW BASIC SERVICE CHARGE DETERMINED?

A. The Company is proposing a gradual but material step increase in the basic service charge. The amount of the proposed increase, $2.50, was to help limit bill impacts that result from subsidy reductions on the residential customers that are currently enjoying the intra-class subsidy being paid by higher use customers.

Q. IS THE PROPOSED BASIC SERVICE CHARGE OF $20.00 PER MONTH APPROACHING FULL COST?

A. No, it is not. In Case No. 2020-00174, the full cost basic service charge was calculated to be roughly $35 per customer per month using the marginal customer connection study methodology. That study identified the Company's current average cost to connect a residential customer to its distribution system. The total cost of the residential connection is then multiplied by the appropriate levelized carrying charge and divided by 12 to compute the monthly full cost basic service charge. In other words, the fixed monthly cost associated with connecting the next customer to the distribution system was $35.

In Case No. 2020-00174, Kentucky Power was directed to perform a zero-intercept study for its class cost of service study. Company Witness Steward performed this analysis and Company Witness Cost incorporated the results into the class cost of service study in this proceeding to calculate the base revenue target for the residential class. The calculated full-cost residential basic service charge, based on data incorporated from the zero-intercept study, is $50.91, which is far above the proposed basic service charge of $20.00. The Company was authorized an increase of 25% to the basic service charge in Case No. 2020-00174 and is proposing a 14% increase in this proceeding to continue to make progress towards full cost.

Q. WILL THE COMPANY'S PROPOSED RESIDENTIAL BASIC SERVICE CHARGE DETER ENERGY CONSERVATION?

A. No. In addition to its proposal to increase the basic service charge, the base rate kWh charge is also increasing. Because the amount charged in a customer's bill is still largely driven by the amount of kWh consumed, the increase in basic service charge is not providing customers a price signal that would encourage additional consumption. An increase in usage will still result in an increased bill.

Ideally, the Company would recover little to none of the residential class distribution revenue requirement through a per kWh charge because the distribution revenue requirement does not vary with the amount of kWh consumed. Instead, the Company would institute a per kW demand charge for residential customers to collect residential distribution costs not recovered through the service charge. However, the Company's current residential class metering infrastructure does not provide the information necessary to institute a per kW demand charge for all customers.

Q. WHAT KIND OF RATE DESIGN WOULD RESULT IN CLEARER PRICE SIGNALS?

A. Using a per kW demand charge to recover the remaining residential distribution system costs would be preferred because the fixed costs of the distribution system are incurred in two ways. First, costs are incurred by simply connecting a customer to the radial distribution system. These connection costs do not vary with the kWh consumed or the kW demands of customers. The Company is proposing to include a larger portion of these connection costs through the increased basic service charge. Second, the Company incurs residential system distribution costs by sizing the distribution system to meet customer peak kW demand. These sizing costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system. These sizing costs would ideally be collected through a demand charge, but this cannot be done for all customers due to the current limitations of the Company's metering infrastructure. In fact, under the Company's proposal, nearly 90% of the Company's residential customer class revenues are still being recovered through a per kWh usage charge. In the absence of a peak demand charge, the Company is proposing to move a portion of those fixed distribution costs that only vary with the number of customers connected to the system from the per kWh charge to the basic service charge.

Similarly, the addition of the residential optional seasonal provision will not deter energy conservation as it only applies to the winter months and is designed to better align distribution cost recovery across the seasons.

Q. IS SENDING THE CORRECT PRICE SIGNALS TO CUSTOMERS THROUGH RATES THAT REFLECT THE TRUE COST OF SERVICE IMPORTANT TO THE LONG TERM SUCCESS OF CONSERVATION EFFORTS?

A. Yes. While in the short term a higher kWh charge that does not reflect the true cost of service could artificially encourage additional conservation, in the long term it provides confusion to customers and can result in customers making uneconomic decisions and causing the inefficient allocation of customers' capital. Customers expect that when they use less energy, the usage-related portion of their bills will decrease. However, to the extent that the usage-related portion of rates are designed to include a portion of the fixed costs as well, it is likely that as those fixed cost collections diminish because the cost savings from reduced usage are less than the loss in fixed cost collection, the Company will need to increase the usage-related portion of rates. When that happens, customers will see the usage-related portion of their bills increase even though they have conserved energy. It is important to send accurate, cost-based price signals to customers, which is exactly what the Company's proposed residential rate design continues to take steps towards.

Q. ARE THERE OTHER COST OF SERVICE JUSTIFICATIONS FOR THE COMPANY TO REQUIRE A HIGHER RESIDENTIAL SERVICE CHARGE THAN THE OTHER KENTUCKY INVESTOR-OWNED UTILITIES?

A. Yes, there are two. First, the Company finds itself in a unique position compared to the other investor-owned utilities in Kentucky as to the overall density of its service territory. The Company has many fewer customers per distribution line (circuit) mile than does its peers, as Company Witness West discusses further. The absence of densely populated urban areas in the Company's service territory results in its makeup being more akin to the rural cooperatives of Kentucky than its fellow investor-owned utilities. As a result, the Company must make more distribution plant investments and incurs higher maintenance costs per customer to provide service. Second, the topography of the Company's service territory, discussed further by Company Witness Phillips, adds to the cost. Kentucky Power's service territory is primarily mountainous creating challenges for distribution system installation and maintenance that other utilities in the Commonwealth do not experience to the same degree. The combination of lower customer density and challenging topography results in a comparatively higher cost based basic service charge.

Q. IN SUMMARY, DOES THE COMPANY'S PROPOSED RESIDENTIAL RATE DESIGN BENEFIT THE COMPANY'S ELECTRIC HEATING AND LOWER INCOME CUSTOMERS?

A. Yes. Because electric heating and lower income customers on average use more kWh than the class average, the reduction of the intra-class subsidy being paid through the volumetric energy charge will benefit them. To put a fine point on it, under the Company's proposed rate design electric heating and lower income customers are better off than they would be on the current rate design at any level of increase.

VI. <u>TARIFF CHANGES AND NEW OFFERINGS</u>

i. <u>Federal Tax Cut Tariff Changes</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE FEDERAL TAX CUT TARIFF.

A. Consistent with the Commission's Order in Case No. 2020-00174, the unprotected excess ADFIT that has been credited to customers through Tariff FTC will be fully refunded to the Company's customers by the time the rates in this proceeding go into effect. As such, Tariff FTC will include only the protected excess ADFIT amortization going forward. In addition, the Company is proposing to include in Tariff FTC actual Corporate Alternative Minimum Tax expense and credits beginning with the rates set for December 2024. Company Witness Schlessman discusses the tax policy rationale for the proposed changes to Tariff FTC. In addition, a redlined version of proposed Tariff FTC, which is being renamed the Federal Tax Change Tariff, is attached to my testimony as Exhibit MMS-2.

ii. <u>Proposed Distribution Reliability Rider ("DRR")</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED DISTRIBUTION RELIABILITY RIDER ("DRR")

A. The necessity of and project detail for the DRR are described in detail by Company Witnesses West and Phillips respectively. For ratemaking purposes, the initial DRR will include the capital and associated operations and maintenance expenses for the following distribution reliability work plan:

1. Vegetation Management Program
2. Distribution Asset Renewal

The initial DRR capital and O&M costs are outlined in Company Witness Phillips' testimony.

Q. PLEASE DESCRIBE THE OPERATION OF THE DRR.

A. The proposed DRR is attached to my testimony as Exhibit MMS-3. As shown, the DRR is only applicable to customers served at distribution (secondary and primary) voltages excluding Outdoor and Street Lighting. The DRR will be updated annually and filed by February 15 for rates effective for the first billing cycle of April.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE PROGRAM COSTS OF PROPOSED TARIFF DRR?

A. The Company proposes that the DRR be recovered from customers on a per bill basis by residential and all other rate schedules, excluding outdoor lighting, street lighting, subtransmission voltage and transmission voltage customers. The residential allocation will be based on the most recent 12-month residential contribution to Kentucky non-fuel retail revenue and the all other allocation will be based on the most recent 12-month all other class contribution to Kentucky non-fuel retail revenue. These amounts are then divided by the most recent 12-month bills for residential, and all other classes, to arrive at the residential and all other factors.

iii. <u>Proposed Securitization Financing Rider ("SFR")</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED SECURITIZATION FINANCING RIDER ("SFR").

A. The necessity, and included regulatory assets, for the SFR is described in detail by Company Witness West. The SFR is designed to recover from customers the amounts necessary to service, repay, and administer customer-backed bonds associated with the approved securitized costs pursuant to the terms of the financing order of the Kentucky Public Service Commission in this proceeding. The SFR will remain in effect until the complete repayment and retirement of any customer-backed bonds, or refunded bonds, associated with the approved securitized costs.

Q. PLEASE DESCRIBE THE RATE DESIGN AND ADJUSTMENT SCHEDULE THE COMPANY IS PROPOSING FOR RIDER SFR.

A. The Company is proposing that the SFR is recovered from customers on a percent of revenue basis, with distinct rates for residential and all other rate schedules. This methodology parallels the methodology currently used for the Decommissioning Rider. The residential allocation will be based on the most recent 12-month residential contribution to Kentucky retail revenue and the all other allocation will be based on the most recent 12-month all other class contribution to Kentucky retail revenue. The SFR actual revenue requirement will be multiplied by the annual residential, and all other, allocation to arrive at the net residential, and all other, revenue requirements. These amounts are then divided by the annual Kentucky residential retail revenue to calculate the residential factor and by all other classes non-fuel retail revenue to calculate the all other adjustment factor.

The Company is proposing to make a semi-annual true-up filing no later than February 15 and August 15 of each calendar year for effective rates with the cycle 1 of the following April and October billing periods. The first semi-annual true-up adjustment will be reduced should there be unused funds because the actual up-front financing costs are less than the up-front financing costs included in the principal amount securitized. In addition, there is the possibility of interim true-up adjustments to correct for any over- or under-collection. Finally, quarterly true-ups will begin 12 months prior to the scheduled final payment date for the latest maturing tranche of securitized bonds of a particular series. Company Witness Niehaus describes the necessity for filing true-ups in order to minimize and stabilize charges on an ongoing basis throughout the life of the transaction.

The proposed SFR is attached to my testimony as Exhibit MMS-4.

Q. HAVE YOU CALCULATED THE ESTIMATED SECURITIZED SURCHARGE NECESSARY TO RECOVER THE SECURITIZED COSTS AND FINANCING COSTS?

A. I have. As calculated by Company Witness Messner, the estimated costs to be recovered over the 20-year period that the SFR will be in effect result in an annual revenue requirement of $37,061,497. The revenue requirement will be allocated to Residential and All Other Non-Residential customers based on total retail revenue. I have computed estimated rider rates to be assessed as a percentage of retail revenue. The estimated Residential SFR Factor of 5.8233% will be assessed on total revenue excluding any percentage of revenue rider amounts. The estimated All Other SFR Factor of 11.440% will be assessed on total revenue excluding any percentage of revenue rider amounts and fuel. The resulting calculation is attached as Exhibit MMS-5.

VII. <u>ECONOMIC DEVELOPMENT RIDER PARTICIPATING CUSTOMER ANALYSIS AND SPECIAL CONTRACT ANALYSIS</u>

Q. HAVE YOU CONDUCTED A MARGINAL COST OF SERVICE ANALYSIS FOR THE COMPANY'S ECONOMIC DEVELOPMENT RIDER ("EDR") CUSTOMER AND WHAT ARE ITS RESULTS?

A. Yes. The marginal cost of service analysis shows that in total the Company's EDR customers are covering their variable cost of service and contributing to the Company's fixed cost of service while taking service under the discounted EDR rates. This analysis is attached to my testimony as Exhibit MMS-6. It was also filed with the Commission on March 30, 2023 in Case No. 2014-00336.

Q. HAVE YOU CONDUCTED A MARGINAL COST OF SERVICE ANALYSIS FOR THE COMPANY'S SPECIAL CONTRACT CUSTOMER AS DIRECTED IN CASE NO. 2020-00019?[2]

A. Yes. I have calculated the marginal cost of service for the special contract customer for the periods of June 2020 through December 2020, Calendar Year 2021, Calendar Year 2022, and Year-to-Date 2023.,. The results are attached as MMS Exhibit-7.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

[2] Order, *In The Matter Of: Electronic Application Of Kentucky Power Company For Approval Of A Contract For Electric Service With Air Products And Chemicals, Inc.,* Case No. 2020-00019 (Ky. P.S.C. April 23, 2020).

Spaeth Verification Form_JAY.doc

DocVerify ID:	0C4C9100-1A33-4B00-8C36-2E3C2783C5FD
Created:	June 27, 2023 11:13:37 -8:00
Pages:	1
Remote Notary:	Yes / State: KY

E-Signature Summary

E-Signature 1: Michael Spaeth (MS)
June 27, 2023 11:16:39 -8:00 [9E992438E2B3] [167.239.221.107]
mmspaeth@aep.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 27, 2023 11:16:39 -8:00 [48AC70D90F8F] [167.239.221.103]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Michael M. Spaeth, being duly sworn, deposes and says he is a Regulatory Pricing and Analysis Manager for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

9E992438E2B3
Michael Spaeth
Signed on 2023/06/27 11:16:39 -8:00

Michael M. Spaeth

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Michael M. Spaeth, on June 27, 2023.

48AC70D90F8F
Signed on 2023/06/27 11:16:39 -8:00

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025
Notary Stamp 2023/06/27 11:16:39 PST 48AC70D90F8F

Notarial act performed by audio-visual communication

Notary Public

My Commission Expires ____06/21/2025____________

Notary ID Number ______KYNP31964_______________

KPCo Kentucky Retail Jurisdiction
Base Rate Revenue Target Summary

	Total Retail 1	RS 2	GS-SEC 3	GS-PRI 4	GS-SUB 5	Total GS	LGS-SEC 6	LGS-PRI 7	LGS-SUB 8	LGS-TRA 9
From CCOS										
Demand	$ 246,155,638	$ 106,196,506	$ 35,458,958	$ 431,275	$ 18,600	$ 35,908,832	$ 19,969,706	$ 5,381,092	$ 871,809	$ -
Energy	$ 188,464,684	$ 69,657,041	$ 21,894,582	$ 262,790	$ 13,058	$ 22,170,430	$ 11,452,355	$ 3,105,235	$ 484,913	$ -
Dist Primary	$ 34,214,909	$ 18,780,077	$ 6,918,693	$ 84,766	$ -	$ 7,003,460	$ 3,984,534	$ 1,073,651	$ -	$ -
Dist Secondary	$ 11,134,614	$ 7,352,102	$ 2,172,466	$ -	$ -	$ 2,172,466	$ 1,090,827	$ -	$ -	$ -
Customer	$ 116,632,520	$ 80,493,812	$ 25,977,816	$ 278,732	$ 17,932	$ 26,274,480	$ 603,125	$ 189,063	$ 75,332	$ -
TOTAL	$ 596,602,365	$ 282,479,538	$ 92,422,515	$ 1,057,563	$ 49,590	$ 93,529,669	$ 37,100,547	$ 9,749,041	$ 1,432,054	$ -
Adjustments										
Unbilled	$ (1,125,502)	$ (1,398,838)	$ (195,502)	$ (10,620)	$ (1,413)		$ 12,513	$ 10,084	$ (2,020)	$ -
D	$ (753,502)	$ (844,746.57)	$ (120,869.32)	$ (6,598.70)	$ (829.99)		$ 7,952.32	$ 6,394.31	$ (1,297.82)	$ -
E	$ (371,999)	$ (554,091.17)	$ (74,632.28)	$ (4,020.82)	$ (582.72)		$ 4,560.55	$ 3,689.93	$ (721.87)	$ -
Base Rate Revenue Targets										
Demand	$ 246,909,140	$ 107,041,253	$ 35,579,828	$ 437,873	$ 19,430	$ 36,037,130	$ 19,961,753	$ 5,374,698	$ 873,107	$ -
Energy	$ 188,836,684	$ 70,211,132	$ 21,969,214	$ 266,811	$ 13,641	$ 22,249,666	$ 11,447,794	$ 3,101,545	$ 485,635	$ -
Dist Primary	$ 34,214,909	$ 18,780,077	$ 6,918,693	$ 84,766	$ -	$ 7,003,460	$ 3,984,534	$ 1,073,651	$ -	$ -
Dist Secondary	$ 11,134,614	$ 7,352,102	$ 2,172,466	$ -	$ -	$ 2,172,466	$ 1,090,827	$ -	$ -	$ -
Customer	$ 116,632,520	$ 80,493,812	$ 25,977,816	$ 278,732	$ 17,932	$ 26,274,480	$ 603,125	$ 189,063	$ 75,332	$ -
	$ 597,727,866	$ 283,878,376	$ 92,618,017	$ 1,068,183	$ 51,002	$ 93,737,202	$ 37,088,035	$ 9,738,957	$ 1,434,073	$ -

	Total LGS	IGS-SEC 10	IGS-PRI 11	IGS-SUB 12	IGS-TRA 13	Total IGS	PS-SEC 14	PS-PRI 15	Total PS	MW 16	OL 17	SL 18
From CCOS												
Demand	$ 26,222,607	$ 581,840	$ 10,807,787	$ 52,523,970	$ 6,714,327	$ 70,627,924	$ 6,136,460	$ 115,428	$ 6,251,887	$ 90,387	$ 666,270	$ 191,223
Energy	$ 15,042,503	$ 541,451	$ 11,317,759	$ 56,809,954	$ 7,982,025	$ 76,651,189	$ 3,257,207	$ 61,287	$ 3,318,494	$ 56,372	$ 1,258,797	$ 309,857
Dist Primary	$ 5,058,185	$ 105,040	$ 1,952,476	$ -	$ -	$ 2,057,516	$ 1,250,941	$ 24,044	$ 1,274,985	$ 18,988	$ 16,689	$ 5,009
Dist Secondary	$ 1,090,827	$ 23,863	$ -	$ -	$ -	$ 23,863	$ 352,692	$ -	$ 352,692	$ 4,687	$ 107,225	$ 30,752
Customer	$ 867,520	$ 3,808	$ 97,129	$ 173,661	$ 33,580	$ 308,177	$ 211,836	$ 2,509	$ 214,345	$ 15,393	$ 7,294,154	$ 1,164,639
TOTAL	$ 48,281,642	$ 1,256,002	$ 24,175,151	$ 109,507,584	$ 14,729,932	$ 149,668,670	$ 11,209,135	$ 203,268	$ 11,412,403	$ 185,827	$ 9,343,135	$ 1,701,481
Adjustments												
Unbilled		$ 3,961	$ 67,368	$ 74,350	$ 343,079		$ (33,813)	$ (1,852)		$ (446)	$ 7,630	$ 15
D		$ 2,051.89	$ 32,907.62	$ 35,717.85	$ 156,742.60		$ (22,088.67)	$ (1,209.43)		$ (274.75)	$ 2,640.64	$ 5.82
E		$ 1,909.46	$ 34,460.39	$ 38,632.45	$ 186,336.37		$ (11,724.58)	$ (642.16)		$ (171.35)	$ 4,989.01	$ 9.43
Base Rate Revenue Targets												
Demand	$ 26,209,558	$ 579,788	$ 10,774,879	$ 52,488,252	$ 6,557,585	$ 70,400,504	$ 6,158,548	$ 116,637	$ 6,275,185	$ 90,662	$ 663,630	$ 191,218
Energy	$ 15,034,975	$ 539,542	$ 11,283,298	$ 56,771,322	$ 7,795,689	$ 76,389,851	$ 3,268,932	$ 61,929	$ 3,330,861	$ 56,543	$ 1,253,808	$ 309,848
Dist Primary	$ 5,058,185	$ 105,040	$ 1,952,476	$ -	$ -	$ 2,057,516	$ 1,250,941	$ 24,044	$ 1,274,985	$ 18,988	$ 16,689	$ 5,009
Dist Secondary	$ 1,090,827	$ 23,863	$ -	$ -	$ -	$ 23,863	$ 352,692	$ -	$ 352,692	$ 4,687	$ 107,225	$ 30,752
Customer	$ 867,520	$ 3,808	$ 97,129	$ 173,661	$ 33,580	$ 308,177	$ 211,836	$ 2,509	$ 214,345	$ 15,393	$ 7,294,154	$ 1,164,639
	$ 48,261,065	$ 1,252,041	$ 24,107,783	$ 109,433,234	$ 14,386,853	$ 149,179,911	$ 11,242,948	$ 205,120	$ 11,448,068	$ 186,273	$ 9,335,506	$ 1,701,465

RS

I. **Proposed Revenue**

	Billed & Accrued Revenue	Fuel Revenue	Base Revenue		
Total RS Revenue Requirement					
Demand	133,173,431	$0	$133,173,431		
Energy	70,211,132	0	$70,211,132		
Customer	80,493,812	0	$80,493,812		
Total	$283,878,376	$0	$283,878,376	$1,398,838	Check

II. **Customer Charge**

Full cost customer charge			=	$50.91	
Proposed Customer Charge			=	**$20.00** /mo.	
Proposed Customer Charge Revenue	1,581,214	x	$20.00	=	$31,624,280

III. **Off-Peak Energy Charge**

Energy Revenue Requirement	$70,211,132				
Total Energy (kWh)	1,948,573,768				
Total Secondary Energy Charge	$0.03603 /kWh				
Fixed Cost Adder	$0.05000 /kWh				
Proposed Off-Peak Energy Charge	$0.08603 /kWh				
Off-Peak % Usage	56.76%				
Off-Peak kWh Energy	1,106,010,471				
Off-Peak Revenue	1,106,010,471	x	$0.08603	=	$95,150,081

IV. **On-Peak Energy Charge**

Total RS Base Revenue	$283,878,376
Less: Customer Revenue	31,624,280
Less: Off-Peak Energy Revenue	95,150,081
On-Peak Revenue	$157,104,015
Total RS Energy	1,948,573,768
Less: Off-Peak kWh Energy	1,106,010,471
On-Peak kWh Energy	842,563,297
Proposed On-Peak Energy Charge	$0.18646 /kWh

V. **Revenue Verification**

	Units	Rate	Revenue	Difference
On-Peak	842,563,297 kWh	$0.18646 /kWh	$157,104,352	
Off-Peak	1,106,010,471 kWh	$0.08603 /kWh	95,150,081	
Customer	1,581,214 Bills	$20.00 /Mo.	31,624,280	
Total	1,948,573,768 kWh		$283,878,713	337

VI. **Time-of-Day Customer Charges**

Current TOD Charge	$21.00			
Proposed Standard Charge	$20.00		Separate Meter Charge	
Actual Differential:				
TOD Meter Cost	$367.32		$367.32	
Standard Meter Cost	$108.50			
Cost Differential	$258.82		$367.32	
Carrying Cost	13.97%		13.97%	15 Year Annual Investment CC
Over 12 Months	12		12	
Differential	$3.01		$4.28	
Proposed RS-TOD/RS-LM-TOD/ RS TOD 2	$23.00		$4.30	
Separate Meter Customer Charge:		Current	$3.75	
		Use:	$4.30	

VII. **RS-TOD / RS-LM-TOD Proposed Revenue**

	Units	Rate	Revenue
On-Peak	1,160,149 kWh	$0.18646 /kWh	$216,321
Off-Peak	1,857,302 kWh	$0.08603 /kWh	159,784
Customer - Std TOD	1,800 Bills	$23.00 /Mo.	41,400
Customer - Sep Meter	94 Bills	$4.30 /Mo.	404
Total	3,017,451 kWh		$417,909

VIII. **Customer Revenue**

Customer Charge Revenue	1,579,320 Bills	x	$20.00 /mo.	=	$31,586,400

IX. **Standard Energy Rates**

Storage Water Heating Revenue	436,918	kWh	x	$0.08603 /kWh (Off-Pk) =	$37,588

Adjusted Base Revenue	283,878,376
Less RS-TOD/RS-LM-TOD Revenue	417,909
Less: Customer Revenue	31,586,400
Less: Storage Water Htg Revenue	37,588
[redacted]	
Energy Charge Revenue - All Blocks	$251,836,479
All kWh	1,945,119,399
Standard Energy Rate - All kWh	$0.12947 /kWh

[redacted]

X. **RS Revenue Verification**

	Units		Rate		Revenue	Difference
All Standard kWh	1,945,119,399	kWh	$0.12947	/kWh	$251,834,609	
[redacted]						
Storage Water Heating	436,918	kWh	$0.08603	/kWh	37,588	
Customer	1,579,320	Bills	$20.00	/mo.	31,586,400	
Total	1,945,556,317	kWh	Proof		$283,458,597	
			Standard Target		$283,460,467	
*Revised after revenue verification			Difference		($1,870)	

XIV. **Residential Summary**

Schedule	Bills	kWh	Revenue	Difference
RS	1,579,320	1,945,556,317	$283,458,597	
RS-TOD / RS LMTOD	1,894	3,017,451	417,909	
Total Billed	1,581,214	1,948,573,768	$283,876,506	($1,870)

Optional Residential Demand Rate

Revenue Targets		
Distribution Primary	$	18,780,077
Distribution Secondary	$	7,352,102
Prod and Trans Demand	$	107,041,253
Energy	$	70,211,132
Customer	$	80,493,812
Total	$	283,878,376

RS-D Billing Units	
On Peak kWh	298,050,826
Off Peak Energy	1,650,522,942
Total kWh	1,948,573,768
Total On-Peak Billing Demand	10,371,705
Total Bills	1,581,214

RS-D Rates		
On Peak Energy Charge	**0.11843**	$/kWh
Off Peak Energy Charge	**0.08603**	$/kWh
On-Peak Demand Charge	**6.77**	$/kW
Customer Charge	**23.00**	$/customer/month

Revenue Verification	**Units**	**Rates**		**Revenue**
On Peak Energy Charge	298,050,826	0.11843	$	35,298,159
Off Peak Energy Charge	1,650,522,942	0.08603	$	141,994,489
On-Peak Demand Charge per kW	10,371,705	6.77	$	70,216,443
Customer Charge	1,581,214	23.00	$	36,367,922
			$	283,877,013
			$	(1,363)

RS TOD2

I. Proposed Revenue

	Total (1)	Production (2)	All Other (3) = (1) - (2)
Demand	133,173,431	$106,196,506	$26,976,925
Energy	70,211,132	$0	$70,211,132
Customer	80,493,812	$0	$80,493,812
Total	$283,878,376	$106,196,506	$177,681,870

III. Basic Energy Charge Rate Design

All Other Revenue	$177,681,870
Less: Customer Charge Revenue - STD	$31,586,400
Customer Charge Revenue - TOD	$41,804
Basic Energy Revenue	$146,053,666
Total kWh	1,948,573,768
Basic Energy Charge Rate	$0.074954

IV. Variable Energy Charge Rate Design

	Market Generation (Excluding Losses)					
	Energy (1)	Capacity (2)	Total (3) = (1) + (2)	Production Charge (4) on (3)	kWh (5)	Variable Energy Charge (6) = (4) / (5)
Summer	22,429,290	3,149,757	25,579,047	$16,531,556	144,694,995	$0.114251
Winter	19,654,170	4,174,563	23,828,732	$15,400,340	250,572,528	$0.061461
Other	111,912,617	2,995,984	114,908,601	$74,264,610	1,553,306,245	$0.047811
	153,996,077	10,320,303	164,316,380	$106,196,506	1,948,573,768	
			Percentage:	64.63%		

V. Energy Base Rate Total

	Basic Energy Charge (1)	Variable Energy Charge (2)	Subtotal (3) = (1) + (2)	Fuel Adjustment (4)	Base Rate (5) = (3) - (4)
Summer	$0.074954	$0.114251	$0.189205	$0.0000000	$0.18921
Winter	$0.074954	$0.061461	$0.136415	$0.0000000	$0.13642
Other	$0.074954	$0.047811	$0.122765	$0.0000000	$0.12277

VI. Revenue Verification

	Units (1)		Rate (2)	Revenue (3) = (1) x (2)		
Customer Charge - STD	1,579,320	Bills	$20.00	$31,586,400		
Customer Charge - TOD	1,800	Bills	$23.00	$41,400		
Customer Charge - TOD - Sep Meter	94	Bills	$4.30	$404		
Summer	144,694,995	kWh	$0.18921	$27,377,740		
Winter	250,572,528	kWh	$0.13642	$34,183,104		
Other	1,553,306,245	kWh	$0.12277	$190,699,408		
Fuel	1,948,573,768	kWh	$0.0000000	$0		
				$283,888,456	$283,878,376	$10,080

* Revised after revenue verification

Residential Seasonal Rate Provision

	Season	Test Year kWh	Rate Design Revenue Targets: Customer	Distribution	Gen & Trans	Total	Proposed Customer Charge Revenue	Proposed Energy Charge Revenue	Proposed Energy Charge	Customer Bills	Monthly kWh per Customer
			$80,493,812	$26,132,179	$177,252,385	$283,878,376	$31,628,204	$252,250,172			
Jan	Winter	286,342,382	6,707,818	2,177,682	26,047,189	34,932,689	2,635,684	32,297,005		131,768	2,173
Feb	Winter	237,548,364	6,707,818	2,177,682	21,608,632	30,494,132	2,635,684	27,858,448		131,768	1,803
Mar	Winter	156,229,680	6,707,818	2,177,682	14,211,463	23,096,962	2,635,684	20,461,278		131,768	1,186
Apr	All other	134,031,369	6,707,818	2,177,682	12,192,189	21,077,688	2,635,684	18,442,005		131,768	1,017
May	All other	114,890,915	6,707,818	2,177,682	10,451,074	19,336,573	2,635,684	16,700,890		131,768	872
Jun	All other	126,997,355	6,707,818	2,177,682	11,552,339	20,437,838	2,635,684	17,802,154		131,768	964
Jul	All other	152,199,747	6,707,818	2,177,682	13,844,879	22,730,378	2,635,684	20,094,695		131,768	1,155
Aug	All other	157,326,594	6,707,818	2,177,682	14,311,244	23,196,743	2,635,684	20,561,059		131,768	1,194
Sep	All other	142,028,977	6,707,818	2,177,682	12,919,693	21,805,192	2,635,684	19,169,509		131,768	1,078
Oct	All other	120,397,296	6,707,818	2,177,682	10,951,963	19,837,462	2,635,684	17,201,779		131,768	914
Nov	All other	123,842,253	6,707,818	2,177,682	11,265,334	20,150,833	2,635,684	17,515,150		131,768	940
Dec	Winter	196,738,836	6,707,818	2,177,682	17,896,386	26,781,885	2,635,684	24,146,201		131,768	1,493
Total		1,948,573,768	80,493,812	26,132,179	177,252,385	283,878,376	31,628,204	252,250,172			1,232
	Winter	876,859,262	$26,831,271	$8,710,726	$79,763,670	$115,305,667	$10,542,735	$104,762,933	$0.11947 *		
	All other	1,071,714,506	$53,662,542	$17,421,452	$97,488,715	$168,572,709	$21,085,469	$147,487,239	$0.13762		

*Revised afer revenue verification

Revenue Verification

	Units (1)	Rate (2)	Revenue (3) = (1) x (2)	Target (4)	Difference (5) = (3) - (4)
Customer Charge - STD	1,579,320 Bills	$20.00	$31,586,400		
Customer Charge - TOD	1,800 Bills	$23.00	$41,400		
Customer Charge - TOD - Sep Meter	94 Bills	$4.30	$404		
All other	1,071,714,506 kWh	$0.13762	$147,489,350		
Winter	876,859,262 kWh	$0.11947	$104,758,376		
			$283,875,930	$283,878,376	($2,446)

SGS TOD

I. Proposed Revenue

	Total (1)	Production (2)	All Other (3) = (1) - (2)
Demand	$44,670,987	$35,579,828	$9,091,160
Energy	$21,969,214	$0	$21,969,214
Customer	$25,977,816	$0	$25,977,816
Total	$92,618,017	$35,579,828	$57,038,189

II. Incremental Meter Charge Rate Design

Annual Incremental Meter Charge		Months		Carrying Charge		Incremental Customer Charge		Plus Standard		Proposed Customer Charge
$0.00	/	12	x	10.78%	=	$0.00	+	$28.00	=	$28.00

III. Basic Energy Charge Rate Design

All Other Revenue	$57,038,189
Less: Customer Charge Revenue - STD	$10,053,120
Customer Charge Revenue - LM-TOD	$21,840
Customer Charge Revenue - NM	$226,335
Customer Charge Revenue - TOD	$168,000
Basic Energy Charge	$46,568,894
Total kWh	627,195,919
Basic Energy Charge Rate	$0.074249

IV. Variable Energy Charge Rate Design

	Market Generation (Excl. Losses)					
	RT LMP (1)	Capacity (2)	Total (3) = (1) + (2)	Production Charge (4) on (3)	kWh (5)	Variable Energy Charge (6) = (4) / (5)
Summer	7,679,927	1,045,131	8,725,057	$6,240,058	51,486,380	$0.121198
Winter	4,862,954	1,284,481	6,147,435	$4,396,573	69,136,748	$0.063592
Other	34,027,084	849,328	34,876,411	$24,943,197	506,572,790	$0.049239
	46,569,965	3,178,621	49,748,903	$35,579,828	627,195,919	
			Percentage:	71.52%		

V. Energy Base Rate Total

	Basic Energy Charge (1)	Variable Energy Charge (2)	Subtotal (3) = (1) + (2)	Fuel Adjustment (4)	Base Rate (5) = (3) - (4)
Summer	$0.074249	$0.121198	$0.195447	$0.0000000	$0.19545
Winter	$0.074249	$0.063592	$0.137841	$0.0000000	$0.13784
Other	$0.074249	$0.049239	$0.123488	$0.0000000	$0.12349

VI. Revenue Verification

	Units (1)		Rate (2)	Billing (3) = (1) x (2)		
Customer Charge - STD	359,040	Bills	$28.00	$10,053,120		
Customer Charge - LM-TOD	780	Bills	$28.00	$21,840		
Customer Charge - NM	15,089	Bills	$15.00	$226,335		
Customer Charge - TOD	6,000	Bills	$28.00	$168,000		
Summer	51,486,380	kWh	$0.19545	$10,063,013		
Winter	69,136,748	kWh	$0.13784	$9,529,809		
Other	506,572,790	kWh	$0.12349	$62,556,674		
Fuel	627,195,919	kWh	$0.0000000	$0		
				$92,618,791	$92,618,017	$774

* Revised after revenue verification

VII. Revenue From Exisiting SGS-TOD Customers

	Units	Rate	Billing	Current
SGS-TOD				
Summer	618,282	$0.19545	$120,843	0.20846
Winter	740,245	$0.13784	$102,035	0.18172
Other	6,636,788	$0.12349	$819,577	0.11279
Customer	6,000	$28.00	$168,000	
Total			$1,210,455	

GS Secondary for TOD/LMTOD/AF Calcs

I. Proposed Revenue

	Billed & Accrued Revenue	Fuel Revenue	Billed & Accrued Revenue Excld Fuel	Base Revenue
Demand	$44,670,987	$0	$44,670,987	$44,670,987
Energy	21,969,214	0	$21,969,214	21,969,214
Customer	25,977,816	0	$25,977,816	25,977,816
Total	$92,618,017	$0	$92,618,017	$92,618,017

II. Non-Metered Customer Charge

Meter Plant (370)	$8,943,459	Customer Base Revenue	$25,977,816
Net Plant/Gross Plant Percentage	59.25%	Less: Meter Plant Revenue	734,862
Depreciated Meter Plant	5,298,999	Meter O&M Expense (586 & 597)	425,377
Return on Rate Base - Class Proposed	10.35%	Meter Reading Expense (902)	116,222
Income	548,446	Adj. Customer Revenue	24,701,355
GRCF	1.339897	/ Bills	380,909
Meter Plant Revenue	734,862	Calculated Non-Metered Customer Charge	64.85
		Current	$14.00
		Use:	$15.00

III. Standard Customer Charge

Customer Revenue	$25,977,816					
Less: Non-Metered Customer Rev.	226,335					
Residual Customer Revenue	$25,751,481	/	359,040 Bills		=	$71.72 /mo.
				Current	=	$25.00 /mo.
					Use:	$28.00 /mo.

GS Sec			349,524		
SGS TOD			6,000		
GS AF			1,032		
MGS TOD			1,704		
GS LMTOD			780		
Standard	$28.00	x	359,040 Bills	=	$10,053,120
GS Non-Metered	$15.00	x	15,089 Bills	=	$226,335

IV. Energy Charges

Revenue Requirement	$92,618,017				
Less: Standard Customer Revenue	10,053,120				
Less: Non-Metered Customer Reve	226,335				
Energy Rate Target	$82,338,562				
GS Sec Standard Energy	594,536,462				
SGS TOD	7,995,316				
GS AF	1,415,369		8,519,716		
MGS TOD	8,519,716		1,798,726		
GS LMTOD	1,798,726		1,415,369		
GS NM	3,136,289				
Total GS Sec Energy	617,401,878				
Recreational Lighting (AF) Energy R	$82,338,562	/	617,401,878	=	$0.13336

V. Revenue Verification

	Units	Rate	Revenue	Difference
Energy	617,401,878 kWh	$0.13336 /kWh	$82,336,714	
Standard Customer	359,040 Bills	$28.00 /mo	10,053,120	
Non-Metered Customer	15,089 Bills	$15.00 /mo	226,335	
Total Base Revenue			$92,616,169	($1,848)

* Revised after revenue verification

VI. Off-Peak Energy Charge

Energy Revenue Requirement	$21,969,214	/	617,401,878 kwh =	$0.03558
Fixed Cost Adder				0.05000
Calculated Off-Peak Energy Charge				$0.08558
Use				$0.08558
Off-Peak % Usage				52.26%
Off-Peak kWh				322,654,221
Off-Peak Revenue				$27,612,748

VII. On-Peak Energy Charge

Total GS Sec Base Revenue	$92,618,017
Less: Standard Customer Revenue	10,053,120
Non-Metered Customer Revenue	226,335
Time-of-Day Off-Peak Revenue	27,612,748
On-Peak Revenue	$54,725,814
On-Peak kWh Energy	294,747,657
Proposed On-Peak Energy Charge	$0.18567 /kWh

VIII. Secondary Revenue Verification

	Units		Rate	Revenue	Difference
On-Peak	294,747,657	kWh	$0.18567	$54,725,797	
Off-Peak	322,654,221	kWh	$0.08558	27,612,748	
Standard Customer	359,040	Bills	$28.00	10,053,120	
Non-Metered Customer	15,089	Bills	$15.00	226,335	
Total Base Revenue				$92,618,000	($17)

*Revised after revenue verification.

IX. Revenue From Existing TOD Customers

	Units	Rate	Proposed Revenue	Current Rates
GS-LM TOD				
On-Peak Energy	706,425	$0.18567	131,162	0.15908
Off-Peak Energy	1,092,300	$0.08558	93,479	0.07915
Customer	780	$28.00	21,840	25
Total			$246,481	
MGS TOD				
On-Peak Energy	3,346,418	$0.18567	621,329	0.15908
Off-Peak Energy	5,173,298	$0.08558	442,731	0.07915
Customer	1,704	$28.00	47,712	25
Total			$1,111,772	

General Service (GS)

I. **Proposed Revenue**

	Secondary	Primary	Subtran	Trans	Total
Proposed Base Revenue					
Demand	$44,670,987	$522,640	$19,430		
Energy	$21,969,214	$266,811	$13,641		
Customer	$25,977,816	$278,732	$17,932		
	$92,618,017	$1,068,183	$51,002		$93,737,202
Fuel Revenue	$0	$0	$0		
Total Base Revenue	$92,618,017	$1,068,183	$51,002		$93,737,202

Secondary Tariff Provisions Base Rev	
Less SGS TOD	$1,210,455
Less MGS TOD	$1,111,772
Less GS LMTOD	$246,481
Less Rec Lighting	$217,650
	$2,786,358

Standard GS Base Revenue Targets	Secondary	Primary	Subtran
Demand	$43,327,087	$522,640	$19,430
Energy	$21,308,283	$266,811	$13,641
Customer	$25,196,289	$278,732	$17,932
	$89,831,659	$1,068,183	$51,002

II. **Billing Determinant Summary**

	Secondary	Primary	Subtran
Standard Service Charge	349,524	864	36
Non-Metered Service Charge	15,089		
First 4450 kWh	360,614,297	2,505,570	103,920
Over 4450 kWh	233,922,165	5,549,355	310,274
Total kWh	594,536,462	8,054,925	414,195
Billing Demand Greater Than 10 kW	1,152,821	23,015	611

III. **GS LMTOD**

	Revenue	Units	Rates
On Peak	$131,162	706,425	0.18567
Off Peak	$93,479	1,092,300	0.08558
Customer	$21,840	780	28.00
	$ 246,481		

IV. **Recreational Lighting**

	Units	Rates	Revenue
Service Charge	1,032	$ 28.00	$ 28,896
Energy Charge	1,415,369	$0.13336 *	$ 188,754
			$ 217,650

* Limited after Revenue Verification

V. **Service Charge Revenue**

	Customer Revenue	Bills	Full Cost Rate	Current Rate	Proposed Rate
Secondary	$25,196,289	349,524	$ 72.09	$ 25.00	$ 28.00
Primary	$278,732	864	$ 322.61	$ 100.00	$ 120.00
Subtransmission	$17,932	36	$ 498.11	$ 400.00	$ 460.00

Proposed Customer Revenue	Proposed Rate	Bills	Revenue
Secondary	$ 28.00	349,524	$ 9,786,672
Primary	$ 120.00	864	$ 103,680
Subtransmission	$ 460.00	36	$ 16,560
Non-Metered	$ 15.00	15,089	$ 226,335
			$ 10,133,247

VI. **Proposed Energy Charges and Revenue**

Proposed Energy Charges

	Units	Proposed Charges	Proposed Energy Revenue	current	class avg inc
Secondary					
First 4450 kWh	360,614,297	0.12292	$ 44,326,709	0.10907	12.7%
Over 4450 kWh	233,922,165	0.10813	$ 25,294,004	0.10201	6%
Primary					
First 4450 kWh	2,505,570	0.10790	$ 270,351	0.09574	
Over 4450 kWh	5,549,355	0.09533	$ 529,020	0.08993	
Subtransmission					
First 4450 kWh	103,920	0.09763	$ 10,146	0.08663	
Over 4450 kWh	310,274	0.08629	$ 26,774	0.08141	
Total Energy Revenue			$ 70,457,003		

VII. **Proposed Demand Charges and Revenue**

Total Base Revenue	$93,737,202
less Secondary Tariff Provisions (TOD	$2,786,358
less Service Charge Revenue	$10,133,247
less Energy Charge Revenue	$70,457,003
less Equipment Credit Revenue	-$12,532
Proposed Demand Revenue	$10,373,126
Loss Adjusted Billing Demand	1,175,641
Residual Demand Charge	8.82

	Billing Demand	Loss Factor	Loss Adjusted Demand
Secondary	1,152,821	1.000	1,152,821
Primary	23,015	0.966	22,238
Subtransmission	611	0.954	583
Total	1,176,447		1,175,641

Equipment Credit Revenue	Billing Demand	45% of Equipment Credit	Revenue
Secondary	1,152,821	$ -	$ -
Primary	23,015	$ (0.49)	$ (11,289)
Subtransmission	611	$ (2.03)	$ (1,243)
Total	1,176,447		$ (12,532)

Demand Rates	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Rate	Proposed Revenue	Current Rates
Secondary	8.82	1.000	8.82	$ -	8.82	$ 10,167,881	$ 6.61
Primary	8.82	0.966	8.52	$ (0.49)	8.03	$ 184,810	$ 6.01
Subtransmission	8.82	0.954	8.41	$ (2.03)	6.38	$ 3,898	$ 4.68
Transmission	8.82	0.940	8.29	$ (2.03)	6.26		
						$ 10,356,590	

VIII. **Revenue Verification**

	Units	Rates	Revenue	Target	Difference
Secondary					
First 4450 kWh	360,614,297	0.12292	$ 44,326,709		
Over 4450 kWh	233,922,165	0.10813	$ 25,294,004		
Billing Demand	1,152,821	$ 8.82	$ 10,167,881		
Customer - Standard	349,524	$ 28.00	$ 9,786,672		
Customer - Non-Metered	15,089	$ 15.00	$ 226,335		
Primary				$ 89,801,601	
First 4450 kWh	2,505,570	0.10790	$ 270,351		
Over 4450 kWh	5,549,355	0.09533	$ 529,020		
Billing Demand	23,015	$ 8.03	$ 184,810		
Customer	864	$ 120.00	$ 103,680		
Subtransmission				$ 1,087,861	
First 4450 kWh	103,920	0.09763	$ 10,146		
Over 4450 kWh	310,274	0.08629	$ 26,774		
Billing Demand	611	$ 6.38	$ 3,898		
Customer	36	$ 460.00	$ 16,560		
				$ 57,377	
			$ 90,946,840	$90,950,845	$ (4,004)

Large General Service (LGS)

I. Proposed Revenue

		Billed and Accrued Revenue	Fuel Revenue	Base Revenue
Secondary	**Includes Schools again**			
Demand		$32,799,296	$0	$32,799,296
Energy		14,716,726	0	14,716,726
Customer		814,961	0	814,961
Total		$48,330,983	$0	$48,330,983
Secondary LM-TOD & TOD		$1,085,532	$0	$1,085,532
Secondary Excl. LM-TOD				
Demand		$32,062,610	$0	$32,062,610
Energy		14,386,183	0	14,386,183
Customer		796,657	0	796,657
Total		$47,245,450	$0	$47,245,450
Primary	**Includes Schools again**			
Demand		$6,589,030	$0	$6,589,030
Energy		3,163,475	0	3,163,475
Customer		191,572	0	191,572
Total		$9,944,076	$0	$9,944,076
Subtransmission				
Demand		$873,107	$0	$873,107
Energy		485,635	0	485,635
Customer		75,332	0	75,332
Total		$1,434,073	$0	$1,434,073
Transmission				
Demand		$0	$0	$0
Energy		0	0	0
Customer		0	0	0
Total		$0	$0	$0
Total LGS Excld LMTOD				
Demand		$39,524,747	$0	$39,524,747
Energy		18,035,292	0	18,035,292
Customer		1,063,561	0	1,063,561
Total		$58,623,600	$0	$58,623,600

II. Billing Determinant Summary

		Secondary	Primary	Subtransmission	Transmission
Total LGS with Schools					
Billing Demand		1,168,110	335,730	31,523	0
Billing Reactive		60,009	77,761	2,930	0
Billing kWh		390,579,985	87,633,137	13,944,800	0
Bills		6,024	840	84	0
Schools		Secondary	Primary		
Billing Demand		336,931	6,357		
Billing Reactive		9,875	136		
Billing kWh		87,428,913	1,737,216		
Bills		1,656	12		
Standard LGS		Secondary	Primary	Subtransmission	Transmission
Billing Demand		831,179	329,373	31,523	0
Billing Reactive		50,134	77,625	2,930	0
Billing kWh		303,151,072	85,895,921	13,944,800	0
Bills		4,368	828	84	0
	avg kWh	64,837	104,325	166,010	-
	avg kW	194	400	375	-

III. Proposed Customer Charges & Revenue

Proposed Customer Charge	Customer Revenue	Bills	Full Cost Rate	Proposed Rate	Overall % increase
Secondary	$796,657	6,024	$132.25	$0.00	13.50%
Primary	191,572	840	$228.06	$0.00	13.50%
Subtransmission	75,332	84	$896.80	$0.00	13.50%
Transmission	0	0	$0.00	$0.00	13.50%
Total	$1,063,561	6,948			

Proposed Customer Revenue	Proposed Rate	Bills	Customer Revenue
Secondary	$0.00	6,024	$0
Primary	$0.00	840	0
Subtransmission	$0.00	84	0
Transmission	$0.00	0	0
Total		6,948	$0

IV. Proposed Excess KVA Charges & Revenue

Proposed KVA Revenue	Proposed/Current Rate	Excess KVA	Revenue
Secondary	$3.46	60,009	$207,631
Primary	$3.46	77,761	269,053
Subtransmission	$3.46	2,930	10,138
Transmission	$3.46	0	0
Total		140,700	$486,822

V. Proposed Demand Charge and Revenue

Calculation of Loss Adj Demand	Maximum Demand	Loss Factor	Loss Adj Demand
Secondary	1,168,110	1.000	1,168,110
Primary	335,730	0.966	324,391
Subtransmission	31,523	0.954	30,062
Transmission	0	0.940	0
Demand	1,535,363		1,522,563

% of Demand EQ Credit

Equipment Credit Revenue	Maximum Demand	Equipment Credit	Credit Revenue
Secondary	1,168,110	0.00	$0
Primary	335,730	(1.09)	($365,946)
Subtransmission	31,523	(4.52)	($142,484)
Transmission	0	(4.52)	$0
Loss Adjusted Demand	1,535,363		($508,430)

Total Required Demand Revenue	$39,037,925
Less: Equipment Credit Revenue	(508,430)
Demand Revenue	$39,546,355
Loss Adjusted Maximum Demand	1,522,563
Full Cost Demand Charge	$25.97
Mitigated % of Demand in Demand Rate	$10.39 *

40% % Demand

Demand Charges	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Demand Rate
Secondary	$10.39	1.000	$10.39	0.000	10.39
Primary	$10.39	0.966	$10.04	-1.090	8.95
Subtransmission	$10.39	0.954	$9.91	-4.520	5.39
Transmission	$10.39	0.940	$9.77	-4.520	5.25

Proposed Demand Revenue	Billing Demand	Proposed Rate	Demand Revenue
Secondary	1,168,110	$10.39	$12,136,663
Primary	335,730	$8.95	3,004,784
Subtransmission	31,523	$5.39	169,909
Transmission	0	$5.25	-
Total	1,535,363		$15,311,356

VI. Proposed Energy Charges and Revenue

Loss Adjusted Energy	Billing Energy	Loss Factor	Loss Adj Energy
Secondary	390,579,985	1.000	390,579,985
Primary	87,633,137	0.953	83,508,430
Subtransmission	13,944,800	0.939	13,095,827
Transmission	0	0.928	0
Total	492,157,922		487,184,242

Equipment Credit Revenue	Billing Energy	60% of Equipment Credit	Equipment Credit Revenue
Secondary	390,579,985	--	0
Primary	87,633,137	(0.00212)	(185,782)
Subtransmission	13,944,800	(0.00856)	(119,367)
Transmission	0	(0.00856)	0
Total	492,157,922		($305,149)

Total Revenue	$58,623,600		
Less: Customer Revenue	0		
Excess KVA Revenue	486,822		
Demand Revenue	15,311,356		
EDR Credit	-35,483		
Equipment Credit Revenue	(305,149)		
Energy Revenue	$43,166,054		
Loss Adjusted Billing Energy	487,184,242	Energy Rate Mitigation	
Secondary Energy Charge	$0.08860		0

	Secondary Rate	Loss Factor	Energy Rate	Equipment Credit	Mitigation	Proposed Rate
Secondary	$0.08860	1.000	$0.08860	0.00000	0.00095	$0.08955
Primary	0.08860	0.953	$0.08443	(0.00212)	(0.00212)	$0.08019
Subtransmission	0.08860	0.939	$0.08321	(0.00856)	(0.01340)	$0.06125
Transmission	0.08860	0.928	$0.08218	(0.00856)	(0.01340)	$0.06022

VII. LGS Total Revenue Verification

		Units	Rate	Revenue
Secondary	Demand	1,168,110 kW	$10.39 /kW	$12,136,663
	Excess KVA	60,009 KVA	3.46 /KVA	207,631
	Energy	390,579,985 kWh	0.08955 /kWh	34,976,438
	Customer	6,024 Bills	0.00 /Mo	0
	Total Billed			$47,320,732
Primary	Demand	335,730 kW	$8.95 /kW	$3,004,784
	Excess KVA	77,761 KVA	3.46 /KVA	269,053
	Energy	87,633,137 kWh	0.08019 /kWh	7,027,301
	EDR Credit			-35,483
	Customer	840 Bills	0.00 /Mo	0
	Total Billed			$10,265,655
Subtran	Demand	31,523 kW	$5.39 /kW	$169,909
	Excess KVA	2,930 KVA	3.46 /KVA	10,138
	Energy	13,944,800 kWh	0.06125 /kWh	854,119
	Customer	84 Bills	0.00 /Mo	0
	Total Billed			$1,034,166
Tran	Demand	0 kW	$5.25 /kW	$0
	Excess KVA	0 KVA	3.46 /KVA	0
	Energy	0 kWh	0.06022 /kWh	0
	Customer	0 Bills	0.00 /Mo	0
	Total Billed			$0

Total Tariff LGS	$58,620,553	
Target	$58,623,600	
Difference	($3,047)	($0.000008)

* Revised after revenue verification

VIII. Off-Peak Energy Charge For LM-TOD

Secondary Energy Revenue Reqt	$14,716,726 /	398,339,975 kwh =	$0.03695
Fixed Cost Adder			0.05000
Calculated Off-Peak Energy Charge			$0.08695
Use:			$0.08695
Off-Peak % Usage - secondary			47.30%
Off-Peak kWh			188,414,808
Off-Peak Revenue			$16,382,668

IX. On-Peak Energy Charge

Total LGS Secondary Base Revenue	$48,330,983
Less: Customer Revenue	0
Time-of-Day Customer Revenue	0
Off-Peak Energy Revenue	16,382,668
On-Peak Revenue	$31,948,315
On-Peak kWh Energy	209,925,167
Proposed On-Peak Energy Charge	$0.15219 /kWh

X. Revenue Verification

	Units	Rate	Revenue	Difference
On-Peak	209,925,167 kWh	$0.15219 /kWh	$31,948,511	
Off-Peak	188,414,808 kWh	$0.08695 /kWh	16,382,668	
Customer - Standard	6,024 Bills	$0.00 /Mo	0	
- Time-of-Day	144 Bills	$0.00 /Mo	0	
Total Base Revenue			$48,331,179	$196

*Revised after revenue verification

XI. Revenue From Existing TOD Customers

	Units	Rate	Proposed Revenue
LGS-LM-TOD			
On-Peak Energy	729,517 kWh	$0.15219 /kWh	$111,025
Off-Peak Energy	1,017,455 kWh	$0.08695 /kWh	88,468
Customer	84 Bills	$0.00 /Mo *	0
			$199,493
LGS TOD SEC			
On-Peak Energy	2,468,161 kWh	$0.12090	$ 298,401
Off-Peak Energy	3,544,856 kWh	$0.06194	$ 219,568
Billing demand	11,058 kW	$9.13	$ 100,960
Excess kVa	5,304 kVa	$3.46	$ 18,352
Customer	60 Bills	$0.00	$ -
			$ 637,280
LGS TOD Primary			
On-Peak Energy	1,028,280 kWh	$0.11521	$ 118,468
Off-Peak Energy	1,257,784 kWh	$0.06021	$ 75,731
Billing demand	6,346 kW	$7.76	$ 49,245
Excess kVa	1,536 kVa	$3.46	$ 5,315
Customer	24 Bills	$0.00	$ -
Total			$ 248,759
*Use same as standard and TOD			$1,085,532

LGS TOD

I. Proposed Revenue

	Secondary	Primary	Subtran	Trans
Proposed Base Revenue				
Demand	$32,799,296	$6,589,030	$873,107	$0
Energy	14,716,726	3,163,475	485,635	0
Customer	814,961	191,572	75,332	0
Total Base Revenue	$48,330,983	$9,944,076	$1,434,073	$0

II. Customer Revenue

	Secondary	Primary	Subtran	Trans
Full Cost Customer Revenue	$814,961	$191,572	$75,332	$0
All Bills	6,108	840	84	0
Calculated Customer Charge	$133.43	$228.06	$896.80	$0.00
Proposed Customer Charge	$0.00	$0.00	$0.00	$0.00
All Bills	6,108	840	84	0
Proposed Customer Revenue	$ -	$ -	$ -	$ -

III. Off-Peak Energy Charge

	Secondary	Primary	Subtran	Trans	Total
Energy Revenue Requirement	$14,716,726	$3,163,475	$485,635	$0	$18,365,836
Total Billing kWh	398,339,975	89,919,201	13,944,800	0	
Loss Factor	1.000	0.953	0.939	0.928	
Loss Adjusted Energy	398,339,975	85,686,894	13,095,827	0	497,122,696
Total Energy Charge	$0.03694	$0.03521	$0.03470	$0.03427	$0.03694
Fixed Cost Adder	$0.02500	$0.02500	$0.02500	$0.02500	
Calculated Off-Peak Energy Charge	$0.06194	$0.06021	$0.05970	$0.05927	
Proposed Off-Peak Energy Charge	$0.06194	$0.06021	$0.05970	$0.05927	
Off-Peak % Usage	47.30%	47.28%	47.08%	47.08%	
Off-Peak kWh	188,414,808	42,513,798	6,565,212	0	
Proposed Off-Peak Charge	$0.06194	$0.06021	$0.05970	$0.05927	
Off-Peak Revenue	$11,670,413	$2,559,756	$391,943	$0	

IV. Demand Charge

	Billing Demand	Proposed Rate *	Demand Revenue
LGS - Secondary	1,168,110	9.13	$10,664,844
- Primary	335,730	7.76	2,605,265
- Subtransmission	31,523	4.40	138,701
- Transmission	0	4.33	0
Total			$13,408,810

* Full cost off-peak rates

V. On-Peak Energy Charge

	Secondary	Primary	Subtran	Trans	Total
Total Revenue	$48,330,983	$9,944,076	$1,434,073	$0	
Less: Customer Revenue	0	0	0	0	
Demand Revenue	10,664,844	2,605,265	138,701	0	
Off-Peak Energy Revenue	11,670,413	2,559,756	391,943	0	
On-Peak Revenue	$25,995,725	$4,779,056	$903,429	$0	$31,678,210
On-Peak kWh	209,925,167	47,405,403	7,379,588	0	
Loss Factor	1.000	0.953	0.939	0.928	
Loss Adjusted Energy	209,925,167	45,174,131	6,930,311	0	262,029,609
Calculated On-Peak Energy Charge	$0.12090	$0.11521	$0.11354	$0.11213	$0.12090
Proposed On-Peak Energy Charge	$0.12090	$0.11521	$0.11354	$0.11213	
On-Peak kWh	209,925,167	47,405,403	7,379,588	0	
On-Peak Revenue	$25,379,953	$5,461,576	$837,878	$0	$31,679,407

Industrial General Service (IGS)

I. Proposed Revenue

	Base Revenue
Demand	$72,481,883
Energy	76,389,851
Customer	308,177
Total	$149,179,911

II. Billing Determinant Summary

Billing Data	Secondary	Primary	Subtransmission	Transmission
On-Peak Billing Demand	14,382	611,130	2,546,312	424,787
Off-Peak Billing Demand	13,558	552,170	2,532,489	417,408
Minimum Billing Demand	18,368	202,839	187,481	11,524
Maximum Monthly Demand kW	32,750	813,969	2,733,793	436,311
Billing Reactive	94	150,031	182,470	47,214
Billing kWh	15,643,440	325,487,812	1,600,613,142	245,809,083
Bills	48	504	264	36

III. Proposed Customer Charges & Revenue

Proposed Customer Charge	Customer Revenue	Bills	Full Cost Rate	Use: Current Rate
Secondary	3,808	48	$79.32	$276
Primary	97,129	504	$192.72	$276
Subtransmission	173,661	264	$657.81	$794
Transmission	33,580	36	$932.77	$1,353
Total	$308,177	852		

Proposed Customer Revenue	Proposed Rate	Bills	Customer Revenue
Secondary	$276	48	13,248
Primary	$276	504	139,104
Subtransmission	$794	264	209,616
Transmission	$1,353	36	48,708
Total		852	$410,676

IV. Proposed Excess KVAR Charges & Revenue

Proposed KVAR Revenue	Use: Current Excess KVAR Rate	Excess KVAR	Revenue
Secondary	$0.69	94	65
Primary	$0.69	150,031	103,521
Subtransmission	$0.69	182,470	125,904
Transmission	$0.69	47,214	32,578
Total		379,809	$262,068

V. Proposed Off-Peak Demand Charges and Revenue

	Off-peak Demand	linked Proposed Rate	Revenue
Secondary	13,558	$1.84	24,947
Primary	552,170	$1.78	982,863
Subtransmission	2,532,489	$1.75	4,431,856
Transmission	417,408	$1.73	722,116
Total	3,515,625		$6,161,782

VI. Proposed Energy Charges and Revenue

Loss Adjusted Energy	Billing Energy	Loss Factor	Loss Adj Energy
Secondary	15,643,440	1.000	15,643,440
Primary	325,487,812	0.953	310,167,788
Subtransmission	1,600,613,142	0.939	1,503,166,224
Transmission	245,809,083	0.928	227,992,213
Total	2,187,553,477		2,056,969,665

Energy Revenue	$76,389,851
Loss Adjusted Billing Energy	2,056,969,665
Secondary Energy Charge	$0.03714
Impact mitigation	-0.00500
Adjusted Secondary Energy Charge	$0.03214

	Secondary Rate	Loss Factor	Calculated Energy Rate	Current Base Fuel Rate
Secondary	$0.03214	1.000	$0.03214	0.02612
Primary	0.03214	0.953	$0.03063	0.02612
Subtransmission	0.03214	0.939	$0.03018	0.02612
Transmission	0.03214	0.928	$0.02981	0.02612

Proposed Energy Revenue

	Billing Energy	Proposed Rate	Revenue
Secondary	15,643,440	$0.03214	502,780
Primary	325,487,812	$0.03063	9,969,692
Subtransmission	1,600,613,142	$0.03018	48,306,505
Transmission	245,809,083	$0.02981	7,327,569
Total	2,187,553,477		$66,106,546

VII. Proposed Minimum Demand Charges and Revenue

Calculation of Loss Adj Demand	Maximum Demand	Loss Factor	Loss Adj Demand
Secondary	32,750	1.000	32,750
Primary	813,969	0.966	786,478
Subtransmission	2,733,793	0.954	2,607,059
Transmission	436,311	0.940	410,176
Total	4,016,823		3,836,463

Equipment Credit Revenue	Maximum Demand	Equipment Credit	Credit Revenue
Secondary	32,750	0.00	$0
Primary	813,969	(1.09)	($887,226)

Subtransmission	2,733,793	(4.52)	($12,356,744)
Transmission	436,311	(4.52)	($1,972,126)
Total	4,016,823		($15,216,096)

Total Required Demand Revenue	$72,481,883
Less: Equipment Credit Revenue	(15,216,096)
Demand Revenue	$87,697,979
Loss Adjusted Maximum Demand	3,836,463
Full Cost Demand Charge	$22.86

Demand Charges	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Rate	Mitigation After Rate Calculation
Secondary	$22.86	1.000	$22.86	0.00	$22.86	$3.15
Primary	$22.86	0.966	$22.09	(1.09)	$21.00	$3.05
Subtransmission	$22.86	0.954	$21.80	(4.52)	$17.28	-$0.64
Transmission	$22.86	0.940	$21.49	(4.52)	$16.97	-$0.68

Proposed Minimum Demand Revenue

	Minimum Demand	Proposed Rate	Revenue
Secondary	18,368	$26.01	477,752
Primary	202,839	$24.05	4,878,278
Subtransmission	187,481	$16.64	3,119,684
Transmission	11,524	$16.29	187,726
Total	420,212		$8,663,440

VII. Proposed On-Peak Demand Charges and Revenue

Calculation of Loss Adj Demand	Billing Demand	Loss Factor	Loss Adj Demand
Secondary	14,382	1.000	14,382
Primary	611,130	0.966	590,490
Subtransmission	2,546,312	0.954	2,428,269
Transmission	424,787	0.940	399,342
Total	3,596,611		3,432,483

Equipment Credit Revenue	Billing Demand	Equipment Credit	Credit Revenue
Secondary	14,382	0.00	$0
Primary	611,130	(1.09)	($666,132)
Subtransmission	2,546,312	(4.52)	($11,509,330)
Transmission	424,787	(4.52)	($1,920,037)
Total	3,596,611		($14,095,499)

Total Required Base Revenue		$149,179,911
Less: Customer Revenue		$410,676
Excess KVAR Revenue		262,068
Off-peak Revenue		6,161,782
CS-IRP Credit Revenue		-1,042,967
EDR/DRS Credit Revenue		-2,930,265
Energy Revenue		66,106,546
Minimum Demand Revenue		8,663,440
Special Contract Billing		2,692,730
Equipment Credit Revenue		(14,095,499)
Demand Revenue		$82,951,400
Loss Adjusted Billing Demand		3,432,483
Full Cost Demand Charge		$24.17
% of Full Cost	100%	$24.17

Demand Charges	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Rate	Mitigation After Rate Calculation	**Current Rate**
Secondary	$24.17	1.000	$24.17	0.00	$24.17	3.15	**25.88**
Primary	$24.17	0.966	$23.35	(1.09)	$22.26	3.05	**22.96**
Subtransmission	$24.17	0.954	$23.05	(4.52)	$18.53	-0.64	**16.33**
Transmission	$24.17	0.940	$22.72	(4.52)	$18.20	-0.68	**16.08**

Proposed On-Peak Demand Revenue

	On-Peak Demand	Proposed Rate	Revenue
Secondary	14,382	$27.32	392,916
Primary	611,130	$25.31	15,467,700
Subtransmission	2,546,312	$17.89	45,553,522
Transmission	424,787	$17.52	7,442,268
Total	3,596,611		$68,856,406

			Units		Rate		Revenue		Target		Difference
VIII.	Revenue Verification										
	Secondary	On-Peak Demand	14,382	kW	$27.32	/kW	$392,916				
		Off-peak Demand	13,558	kW	1.84	/kW	24,947				
		Minimum Demand	18,368	kW	26.01	/kW	477,752				
		Excess KVAR	94	KVAR	0.69	/KVAR	65				
		Energy	15,643,440	kWh	0.03214	/kWh	502,780				
		Customer	48	Bills	276.00	/Mo	13,248				
		Total Billed					$1,411,708	$	1,252,040.71	11%	
	Primary	On-Peak Demand	611,130	kW	$25.31	/kW	$15,467,700				
		Off-peak Demand	552,170	kW	1.78	/kW	982,863				
		Minimum Demand	202,839	kW	24.05	/kW	4,878,278				
		CS-IRP Demand Credit	85,248		-3.68	/kW	-313,713				
		EDR					-158,082				
		Excess KVAR	150,031	KVAR	0.69	/KVAR	103,521				
		Energy	325,487,812	kWh	0.03063	/kWh	9,969,692				
		Customer	504	Bills	276.00	/Mo	139,104				
		Total Billed					$31,069,363	$	24,107,783.22	22%	
	Subtran	On-Peak Demand	2,546,312	kW	$17.89	/kW	$45,553,522				
		Off-peak Demand	2,532,489	kW	1.75	/kW	4,431,856				
		Minimum Demand	187,481	kW	16.64	/kW	3,119,684				
		CS-IRP Demand Credit	164,009		-3.68	/kW	-603,553				
		EDR/DRS/Special Billing					-79,453				
		Excess KVAR	182,470	KVAR	0.69	/KVAR	125,904				
		Energy	1,600,613,142	kWh	0.03018	/kWh	48,306,505				
		Customer	264	Bills	794.00	/Mo	209,616				
		Total Billed					$101,064,081	$	109,433,234.14	-8%	
	Tran	On-Peak Demand	424,787	kW	$17.52	/kW	$7,442,268				
		Off-peak Demand	417,408	kW	1.73	/kW	722,116				
		Minimum Demand	11,524	kW	16.29	/kW	187,726				
		CS-IRP Demand Credit	34,158		-3.68	/kW	-125,701				
		Excess KVAR	47,214	KVAR	0.69	/KVAR	32,578				
		Energy	245,809,083	kWh	0.02981	/kWh	7,327,569				
		Customer	36	Bills	1,353.00	/Mo	48,708				
		Total Billed					$15,635,264	$	14,386,853.29	8%	
	Total Tariff IGS				Base		$149,180,416	$	149,179,911.37	0%	
	* Revised after revenue verification										
	revenue target						$149,179,911		$504		$0.00

Kentucky Power Company
MW Rate Design
Twelve Months Ended March 31, 2023

I. Revenue

	Billed & Accrued Revenue	Fuel	Base Revenue
Demand	114,337	0	114,337
Energy	56,543	0	56,543
Customer	15,393	0	15,393
Total	186,273	0	186,273

II. Customer Charge

Full Cost Customer Charge	$ 15,393	/	96	bills	$ 160.34	/mo.
				Current:	$ 25.00	/mo.
				Proposed	$ 25.00	
Customer Revenue	96 Bills	X	$25.00	/mo.	$ 2,400	

III. Demand Charge

Demand Revenue Requirement	$ 114,337
Monthly Demand (SNCP)	3,302
Full Cost Demand Charge	34.63
Current Minimum Demand Charges	8.89
Class Increase	7.40%
Proposed Minimum Demand Charge	9.55
Minimum kW	1,106
Minimum Demand Charge Revenue	$ 10,565

IV. Energy Charge

Energy Revenue Requirement	
Total MW Revenue Requirement	$ 186,273
Less: Customer Revenue	2,400
Less: Minimum Demand Revenue	10,565
Energy Charge Revenue	$ 173,308
Billing kWh	1,646,859
Proposed Energy Charge	0.10524

V. Revenue Verification

	Units	Proposed Charges	Revenue	Target Revenue	Difference
Energy	1,646,859	$0.10524	173,315		
Demand	1,106	$9.55	10,565		
Customer	96	$25.00	2,400		
Total MW Verified Revenues			186,280	186,273	7

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Tariff #	Lamp Type & Size (1)	Annual Number of Lamps (2)	Present Rate (3)	Present Revenue (4)=(2*3)	Cost Based Rate (5)	Proposed Rate (6)	Proposed Revenue (7)=(2*6)	Annual Increase (8)	Percent Increase (9)=(8/4)	Monthly kWh	Base Fuel Revenue 0.02612	**Non-Fuel Base Rate**
	High Pressure Sodium											
94	100 Watt	195,888	$9.06	$1,774,745	$11.11	$10.53	$2,062,701	$287,956	16.23%	40.3	$ 1.05	$10.53
113	150 Watt	185,952	$10.33	$1,920,884	$13.12	$12.01	$2,233,284	$312,400	16.26%	58.7	$ 1.53	$12.01
97	200 Watt	18,240	$12.52	$228,365	$16.60	$14.55	$265,392	$37,027	16.21%	84.3	$ 2.20	$14.55
103	250 Watt	36.00	$17.84	$642	$21.68	$20.74	$747	$105	16.26%	103	$ 2.69	$20.74
98	400 Watt	2,964	$19.78	$58,628	$27.15	$22.99	$68,142	$9,514	16.23%	166.7	$ 4.35	$22.99
111	100 Watt Post Top	8,364	$16.42	$137,337	$29.48	$19.09	$159,669	$22,332	16.26%	40.3	$ 1.05	$19.09
122	150 Watt Post Top	840	$25.83	$21,697	$31.60	$30.03	$25,225	$3,528	16.26%	58.7	$ 1.53	$30.03
107	200 Watt Floodlight	19,284	$14.38	$277,304	$18.74	$16.72	$322,428	$45,124	16.27%	84.3	$ 2.20	$16.72
109	400 Watt Floodlight	45,552	$21.00	$956,592	$28.54	$24.41	$1,111,924	$155,332	16.24%	166.7	$ 4.35	$24.41
121	100 Watt Shoebox	-	$0.00	$0	$31.71	$0.00	$0	$0	0.00%	0	$ -	$0.00
120	250 Watt Shoebox	24	$30.07	$722	$39.15	$34.96	$839	$117	16.26%	103	$ 2.69	$34.96
126	400 Watt Shoebox	48.00	$39.47	$1,895	$46.63	$45.88	$2,202	$307	16.24%	166.7	$ 4.35	$45.88
	Metal Halide											
110	250 Watt Floodlight	1,944	$17.45	$33,923	$21.59	$20.29	$39,444	$5,521	16.28%	100.3	$ 2.62	$20.29
116	400 Watt Floodlight	10,488	$21.98	$230,526	$28.41	$25.55	$267,968	$37,442	16.24%	158	$ 4.13	$25.55
131	1000 Watt Floodlight	924	$40.01	$36,969	$55.40	$46.51	$42,975	$6,006	16.25%	378.3	$ 9.88	$46.51
130	250 Watt Mongoose	120.00	$22.76	$2,731	$26.93	$26.46	$3,175	$444	16.26%	100.3	$ 2.62	$26.46
136	400 Watt Mongoose	144.00	$27.78	$4,000	$33.78	$32.29	$4,650	$650	16.23%	158	$ 4.13	$32.29
	Mercury Vapor *											
93	175 Watt	5,880	$11.55	$67,914		$13.43	$78,968	$11,054	16.28%	72.0	$ 1.88	$13.43
95	400 Watt	852	$19.88	$16,938		$23.11	$19,690	$2,752	16.25%	158	$ 4.13	$23.11
99	175 Post Top	60	$13.25	$795		$15.40	$924	$129	16.23%	72.0	$ 1.88	$15.40
	Light Emitting Diode (LED)											
150,151,152,153	55W LED OH	153,420	$6.62	$1,015,640	$5.38	$7.70	$1,181,334	$165,694	16.31%	15.8	$ 0.41	$7.70
160	55W LED UG	120	$19.05	$2,286	$5.38	$22.15	$2,658	$372	16.27%	26.4	$ 0.69	$22.15
165	100W LED OH	2,556	$24.75	$63,261	$6.94	$28.77	$73,536	$10,275	16.24%	59.7	$ 1.56	$28.77
166	100W LED UG	984	$30.40	$29,914	$6.94	$35.34	$34,775	$4,861	16.25%	121.4	$ 3.17	$35.34
	Facilities Charge											
	Pole	50,339	$3.61	$181,724	$10.03	$4.20	$211,424	$29,700	16.34%			
	Span	53,732	$2.00	$107,463	$2.15	$2.33	$125,195	$17,732	16.50%			
	Lateral	558	$6.77	$3,776	$7.51	$7.87	$4,390	$614	16.25%			
	Base Revenue			$7,176,672			$8,343,659	$1,166,988				
	Base Fuel						$987,784					
	Total						$9,331,443					
	Revenue Target						$9,335,506					
	Difference						-$4,062					
	Class Increase	16.25%										
	Maximum Increase (1.5 x class increa	24.38%										
	Scale Factor	0.9250										

* In process of elimination (Overall Increase)

OL

Lamp Type & Size (1)	Estimated Installed Cost (2)	Monthly Facility Cost (3)=(2)*FCCR	Annual Maintenance Cost (4)	Consumption in kWh Annual (5)	Consumption in kWh Monthly (6)	Energy Cost no Fuel @ $0.08698 per kWh (7)=(6)*EC	Estimated Monthly Maintenance (8)	Lighting Cost Estimate (9)=(3+7+8)
High Pressure Sodium (HPS)								
100 Watt	$283.12	$4.05	$30.01	484	40.3	$4.56	$2.50	$11.11
150 Watt	$280.86	$4.02	$29.55	704	58.7	$6.64	$2.46	$13.12
200 Watt	$321.65	$4.60	$29.65	1,012	84.3	$9.53	$2.47	$16.60
250 Watt	$529.31	$7.57	$29.53	1,236	103.0	$11.65	$2.46	$21.68
400 Watt	$405.63	$5.80	$29.96	2,000	166.7	$18.85	$2.50	$27.15
100 Watt Post Top	$1,572.06	$22.48	$29.24	484	40.3	$4.56	$2.44	$29.48
150 Watt Post Top	$1,573.64	$22.50	$29.55	704	58.7	$6.64	$2.46	$31.60
200 Watt Floodlight	$471.29	$6.74	$29.65	1,012	84.3	$9.53	$2.47	$18.74
400 Watt Floodlight	$503.05	$7.19	$29.96	2,000	166.7	$18.85	$2.50	$28.54
100 Watt Shoebox	$1,728.32	$24.71	$29.24	484	40.3	$4.56	$2.44	$31.71
250 Watt Shoebox	$1,751.27	$25.04	$29.53	1,236	103.0	$11.65	$2.46	$39.15
400 Watt Shoebox	$1,767.70	$25.28	$29.96	2,000	166.7	$18.85	$2.50	$46.63
Metal Halide								
250 Watt Floodlight	$530.46	$7.59	$31.88	1,204	100.3	$11.34	$2.66	$21.59
400 Watt Floodlight	$547.40	$7.83	$32.48	1,896	158.0	$17.87	$2.71	$28.41
1000 Watt Floodlight	$696.51	$9.96	$31.75	4,540	378.3	$42.79	$2.65	$55.40
250 Watt Mongoose	$903.89	$12.93	$31.88	1,204	100.3	$11.34	$2.66	$26.93
400 Watt Mongoose	$922.89	$13.20	$32.48	1,896	158.0	$17.87	$2.71	$33.78

	Fixed Cost CC Rate Using 10-Yr Inv Life
Return	6.93%
Depreciation	8.21%
F.I.T.	0.60%
Prop Taxes, Adm & Gen'l	1.40%
Annual Total	17.14%
Monthly Total FCCRR	1.43%

Outdoor Lighting (OL) Cost of Service

Demand Revenue Requirement	$770,854
Energy Revenue Requirement	$1,253,808
Cust. Related Revenue Reqt.	
O&M Expenses	$1,520,098
Taxes Other	$384,796
State Income Tax	$137,227
Less: Acct. 598	$0
B&A Rev Excl Direct Ltg Costs	$4,066,783
Class Metered Energy	35,957,675
Energy Rate ($/kWh)	$0.11310

SL

				Cost Based		scaled						
	Annual					Proposed						
Lamp	Number of	Present			Lamp			Annual	Percent		Base Fuel	**Non-Fuel**
Type & Size	Lamps	Rate	Revenue	Lamp	w/pole	Rate	Revenue	Increase	Increase	Monthly kWh	Revenue	**Base Rate**
(1)	(2)	(3)	(4)=(2*3)	(5)	(6)	(7)	(8)=(2*7)	(9)	(10)=(8/4)		0.02612	
Service on Existing Wood Poles												
9,500 Lumen HPS	90,085	$7.61	685,547	8.28	n.a.	$8.49	764,821	79,274	11.56%	40.3	1.05	$8.49
16,000 Lumen HPS	1,201	$8.36	10,040	9.31	n.a.	$9.32	11,193	1,153	11.48%	58.7	1.53	$9.32
22,000 Lumen HPS	26,674	$9.90	264,069	11.16	n.a.	$11.04	294,477	30,408	11.52%	84.3	2.2	$11.04
50,000 Lumen HPS	6,257	$13.00	81,342	15.85	n.a.	$14.50	90,727	9,385	11.54%	166.7	4.35	$14.50
LED - 7,900-9,900 Lumens	3,507	$8.71	30,545			$9.71	34,051	3,506	11.48%	27.75	0.72	$9.71
LED - 10,500-12,500 Lumens	132	$11.19	1,478			$12.48	1,649	171	11.53%	38.17	1	$12.48
LED - 24,000-26,000 Lumens	120	$13.34	1,602			$14.87	1,786	184	11.47%	77.92	2.04	$14.87
Post Top 4,300-6,300 Lumens	1,105	$9.05	9,999			$10.09	11,148	1,149	11.49%	26.42	0.69	$10.09
Post Top 7,300-9,300 Lumens		$20.07	0			$22.38	0	0	11.51%	38.167	1	$22.38
Flood 19,500-21,500 Lumens		$14.69	0			$16.38	0	0	11.50%	59.667	1.56	$16.38
Service on New Wood Poles												
9,500 Lumen HPS	5,320	$11.90	63,312	8.28	14.21	$13.27	70,600	7,288	11.51%	40.3	1.05	$13.27
16,000 Lumen HPS	312	$12.75	3,981	9.31	15.20	$14.22	4,440	459	11.53%	58.7	1.53	$14.22
22,000 Lumen HPS	6,305	$14.30	90,163	11.16	16.98	$15.94	100,503	10,340	11.47%	84.3	2.2	$15.94
50,000 Lumen HPS	1,549	$18.35	28,429	15.85	21.48	$20.46	31,698	3,269	11.50%	166.7	4.35	$20.46
LED - 7,900-9,900 Lumens	72	$14.36				$16.01	1,154	1,154	11.49%	27.75	0.72	$16.01
LED - 10,500-12,500 Lumens		$16.85				$18.79	0	0	11.51%	38.17	1	$18.79
LED - 24,000-26,000 Lumens		$19.00				$21.19	0	0	11.53%	77.92	2.04	$21.19
Post Top 4,300-6,300 Lumens		$14.70				$16.39	0	0	11.50%	26.42	0.69	$16.39
Post Top 7,300-9,300 Lumens		$25.73				$28.69	0	0	11.50%	38.17	1	$28.69
Flood 19,500-21,500 Lumens		$20.35				$22.69	0	0	11.50%	59.67	1.56	$22.69
Service on New Metal or Concrete Poles												
9,500 Lumen HPS	-	$24.80	0	8.28	26.71	$27.65	0	0	11.49%	40.3	1.05	$27.65
16,000 Lumen HPS	-	$25.70	0	9.31	27.70	$28.66	0	0	11.52%	58.7	1.53	$28.66
22,000 Lumen HPS	1,069	$27.25	29,127	11.16	29.48	$30.38	32,472	3,345	11.49%	84.3	2.2	$30.38
50,000 Lumen HPS	853	$30.35	25,879	15.85	33.98	$33.84	28,855	2,976	11.50%	166.7	4.35	$33.84
LED - 7,900-9,900 Lumens		$25.10	0			$27.99	0	0	11.51%	27.75	0.72	$27.99
LED - 10,500-12,500 Lumens	12	$26.78	322			$29.86	359	37	11.50%	38.17	1	$29.86
LED - 24,000-26,000 Lumens	24	$28.11	675			$31.34	753	78	11.49%	77.92	2.04	$31.34
Post Top 4,300-6,300 Lumens		$25.85	0			$28.82	0	0	11.49%	26.42	0.69	$28.82
Post Top 7,300-9,300 Lumens		$36.74	0			$40.97	0	0	11.51%	38.17	1	$40.97
Flood 19,500-21,500 Lumens		$29.42	0			$32.80	0	0	11.49%	59.67	1.56	$32.80
											0	$0.00
Subtotal							$1,480,686	$154,176				
Base Fuel							$220,099					
Total							$1,700,785					
Revenue Target							$1,701,465					
Difference							-$681					
Maximum Increase (1.5 x class increase	11.50%											
Scale Factor	1.0000											

SL

Lamp Type & Size (1)		Estimated Installed Cost (2)	Monthly Facility Cost (3)=(2)*FCCRR	Annual Maintenance Cost (4)	Consumption in kWh Annual (5)	Consumption in kWh Monthly (6)	Energy Cost No Fuel @ $0.05261 per kWh (7)=(6)*EC	Estimated Monthly Maintenance (8)	Lighting Cost Estimate (9)=(3+7+8)
Service on Existing Wood Poles									
High Pressure Sodium (HPS)									
9,500 Lumen		$359.58	$3.72	$29.24	484	40.3	$2.12	$2.44	$8.28
16,000 Lumen		$363.00	$3.76	$29.55	704	58.7	$3.09	$2.46	$9.31
22,000 Lumen		$410.81	$4.25	$29.65	1,012	84.3	$4.44	$2.47	$11.16
50,000 Lumen		$442.78	$4.58	$29.96	2,000	166.7	$8.77	$2.50	$15.85
LED	**Lumens**								
55 Watt OH		5400	$6.43			16	$0.83	$1.28	$8.55
100 Watt OH		10500	$7.64			60	$3.14	$1.76	$12.54
175 Watt OH		18430	$8.21			0	$0.00	$1.99	$10.20
65 Watt Post Top		7230	$5.53			0	$0.00	$2.36	$7.89
90 Watt Dec Post Top		7038	$13.20			30	$1.58	$5.55	$20.33
175 Watt Flood		21962	$9.39			0	$0.00	$2.16	$11.55

Lamp Type & Size (1)		Lamp Cost (2)	Pole Type (3)	Pole Cost (4)	Estimated Installed Cost (5)	Monthly Facility Cost (6)=(5)*FCCRR	Annual Maintenance Cost (7)	Consumption in kWh Annual (8)	Consumption in kWh Monthly (9)	Energy Cost @ $0.05022 per kWh (10)=(6)*EC	Estimated Monthly Maintenance (11)	Lighting Cost Estimate (12)=(5+10+11)
Service on New Wood Poles												
High Pressure Sodium (HPS)												
9,500 Lumen		$359.58		582.53	$942.11	$9.75	$29.24	484	40.3	$2.02	$2.44	$14.21
16,000 Lumen		$363.00		582.53	$945.53	$9.79	$29.55	704	58.7	$2.95	$2.46	$15.20
22,000 Lumen		$410.81		582.53	$993.34	$10.28	$29.65	1,012	84.3	$4.23	$2.47	$16.98
50,000 Lumen		$442.78		582.53	$1,025.31	$10.61	$29.96	2,000	166.7	$8.37	$2.50	$21.48
LED	**Lumens**											
55 Watt OH		5,400	$6.43			$ 12.46			16	$0.83	$1.28	$14.58
100 Watt OH		10,500	$7.64			$ 13.67			60	$3.14	$1.76	$18.57
175 Watt OH		18,430	$8.21			$ 14.24			0	$0.00	$1.99	$16.23
65 Watt Post Top		7,230	$5.53			$ 11.56			0	$0.00	$2.36	$13.92
90 Watt Dec Post Top		7,038	$13.20			$ 19.23			30	$1.58	$5.55	$26.36
175 Watt Flood		21,962	$9.39			$ 15.42			0	$0.00	$2.16	$17.58
Service on New Metal or Concrete Poles												
High Pressure Sodium (HPS)												
9,500 Lumen		$359.58		1,790.13	$2,149.71	$22.25	$29.24	484	40.3	$2.02	$2.44	$26.71
16,000 Lumen		$363.00		1,790.13	$2,153.13	$22.28	$29.55	704	58.7	$2.95	$2.46	$27.70
22,000 Lumen		$410.81		1,790.13	$2,200.94	$22.78	$29.65	1,012	84.3	$4.23	$2.47	$29.48
50,000 Lumen		$442.78		1,790.13	$2,232.91	$23.11	$29.96	2,000	166.7	$8.37	$2.50	$33.98
LED	**Lumens**											
55 Watt OH		5400	$6.43			$ 24.96			0	$0.00	$1.28	$26.25
100 Watt OH		10500	$7.64			$ 26.17			0	$0.00	$1.76	$27.93
175 Watt OH		18430	$8.21			$ 26.74			12	$0.66	$1.99	$29.39
65 Watt Post Top		7230	$5.53			$ 24.06			14	$0.72	$2.36	$27.14
90 Watt Dec Post Top		7038	$13.20			$ 31.73			14	$0.75	$5.55	$38.03
175 Watt Flood		21962	$9.39			$ 27.92			12	$0.61	$2.16	$30.69

	FCCRR 20-Yr Inv Life
Return	6.93%
Depreciation	3.36%
F.I.T.	0.73%
Prop Taxes, Adm & Gen'l	1.40%
Annual Total	12.42%
Monthly Total FCCRR	1.04%

Street Lighting (SL) Cost of Service	
Demand-Related Revenue Reqmt	$221,970
Energy-Related Revenue Reqmt	309,848
Customer-Related Revenue Requirement	
O&M Expenses	216,967
Taxes Other	44,659
State Income Tax	20,010
Less: Account 585	85,965
Account 596	61,349
B&A Rev Excl Direct Ltg Cost	$666,140
Class Metered Energy	8,461,026
Energy Rate ($/kWh)	$0.07873

KENTUCKY POWER COMPANY
Alternate Feed Service (AFS) Rate Design
Twelve Months Ended February 28, 2023

AFS Monthly Cost / Reservation Demand Charge

Primary Demand & Customer Revenue Requirement		$15,394,146	
Functional Demand kW @ Secondary	/	$4,491,888	
Monthly Cost @ Secondary	=	$3.43	
Loss Factor Secondary to Primary	x	0.966225897	
AFS Monthly Cost @ Primary	=	**$3.31**	
Proposed Rate (same as current)	=	**$6.38**	$/kW

AFS Transfer Switch Monthly Testing Rate

Total Annual AFS Transfer Switch Testing Cost		$189.00	
Divided by 12	/	12	
Total Monthly AFS Transfer Switch Testing Rate	=	**$15.75**	$/bill

KENTUCKY POWER COMPANY
Full Cost Off-Peak Demand Charges
Twelve Months Ended March 31, 2023

	Demand Loss Factors	Production	Full Cost Charges
Functional Demand Cost		18.42	
Off-Peak Recovery %		10%	
Off Peak Demand Cost		1.84	
Secondary Charge	1.000	1.84	$1.84
Primary Charge	0.966	1.78	$1.78
Subtran Charge	0.954	1.75	$1.75
Transmission Charge	0.940	1.73	$1.73

KENTUCKY POWER COMPANY
Equipment Credits Relative to Secondary
Twelve Months Ended March 31, 2023

Current Energy Summary

	Secondary	Primary	Subtran	Bulk Tran	Production
GS	617,401,878	8,054,925	414,195		
LGS and PS	398,339,975	89,919,201	13,944,800	0	
IGS	15,643,440	325,487,812	1,736,165,142	245,809,083	
Total	1,031,385,292	423,461,938	1,750,524,137	245,809,083	
Relative Loss Factor	1.00000	0.95293	0.93912	0.92752	
Loss Adj Energy	1,031,385,292	403,530,479	1,643,950,488	227,992,213	
	77.1%	77.1%			
Energy Served by Subtran System	794,865,939	310,992,057	1,643,950,488		
Functional Demand Rev	3,639,848	15,394,146	0	0	138,922,378
Functional Energy	1,031,385,292	1,434,915,771	2,749,808,484	3,306,858,472	3,306,858,472
Functional Cost	0.00353	0.01073	0.00000	0.00000	0.04201

Full Cost Equipment Credits

	Secondary	Primary	Subtran	Total	
Primary	0.00353			0.00353	-0.00353
Subtransmission	0.00353	0.01073		0.01426	-0.01426
Transmission	0.00353	0.01073	0.00000	0.01426	-0.01426

TOD and AF Energy

	Metered kWh
LGS-Sec and PS-Sec	390,579,985
LGS-LM-TOD	1,746,972
LGS-TOD	6,013,018
Total LGS-Sec	398,339,975

KENTUCKY POWER COMPANY
Equipment Credits Relative to Secondary
Twelve Months Ended March 31, 2023

Current Billing Demand Summary	Secondary	Primary	Subtran	Bulk Tran	Production
GS	2,130,005	28,709	793		
LGS and PS	1,184,393	342,076	31,523	0	
IGS	32,750	813,969	2,733,793	436,311	
Total	3,347,148	1,184,754	2,766,109	436,311	
Relative Loss Factor	1.00000	0.96623	0.95364	0.94010	
Loss Adj Demand	3,347,148	1,144,740	2,637,876	410,176	
	77.07%	77.07%			
Demand Served by Subtran System	2,579,573	882,226	2,637,876		
Functional Demand Rev	3,639,848	15,394,146	0	0	138,922,378
Functional Demand	3,347,148	4,491,888	6,099,675	7,539,940	7,539,940
Functional Cost	1.09	3.43	0.00	0.00	18.42

Full Cost Equipment Credits (Relative to Secondary)	Secondary	Primary	Subtran	Total	
Primary	1.09			**1.09**	-1.09
Subtransmission	1.09	3.43		**4.52**	-4.52
Transmission	1.09	3.43	0.00	**4.52**	-4.52

TOD and AF Demands	Standard		Other	
	Metered kWh	Billing Demand	Metered kWh	Billing Demand
GS-Sec (211,215, 218)	594,536,462	2,051,120		
SGS TOD (227)			7,995,316	27,583
GS AF (214)			1,415,369	4,883
MGS TOD (229)			8,519,716	29,393
GS LMTOD (223,225)			1,798,726	6,206
GS NM (213)			3,136,289	10,820
LGS-Sec	390,579,985	1,168,110		
LGS-LM-TOD			1,746,972	5,225
LGS TOD	6,013,018	11,058		

KENTUCKY POWER COMPANY
Full Cost Off-Peak Excess
Twelve Months Ended March 31, 2023

	Demand Loss Factors	Distribution Secondary	Distribution Primary	Subtran	Bulk Tran	Production	Full Cost Charges
Functional Demand Cost		1.09	3.43	0.00	0.00	18.42	
Off-Peak Recovery %		100%	100%	25%	25%	25%	
Off Peak Demand Cost		1.09	3.43	0.00	0.00	4.61	
Secondary Charge	1.000	1.09	3.43	0.00	0.00	4.61	$9.13
Primary Charge	0.966		3.31	0.00	0.00	4.45	$7.76
Subtran Charge	0.954			0.00	0.00	4.40	$4.40
Transmission Charge	0.940				0.00	4.33	$4.33

Kentucky Power
Annual Investment Carrying Charges
For Economic Analyses

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	6.93	6.93	6.93	6.93	6.93	6.93	6.93	6.93	6.93	6.93	6.93	6.93
Depreciation (2)	49.11	32.04	23.49	18.37	8.21	4.93	3.36	2.46	1.89	1.65	1.24	0.90
FIT (3) (4)	0.99	0.72	0.76	0.64	0.60	0.71	0.73	0.63	0.56	0.53	0.48	0.44
Property Taxes, General & Admin Expenses	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40
	58.43	41.09	32.58	27.34	17.14	13.97	12.42	11.42	10.78	10.51	10.05	9.67

(1) Company Proposed Rate of Return

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

COGEN
I.

Capacity Credit Calculation

$$C = \frac{Net\ CONE\ x\ Days\ in\ Year}{Months\ in\ Year\ x\ 1{,}000\ kw}$$

TOD Measurement

C=	2023/2024	$8.36	kw/month
	2024/2025	$8.92	kw/month
	2025/2026	$7.79	kw/month

Standard Measurement

2023/2024	$3.48	kw/month
2024/2025	$3.72	kw/month
2025/2026	$3.25	kw/month

Non-Time-of-Day Energy Payment

		On-Peak	Off-Peak		
Hours per Year	x	3,650	5,110		hours
Hours Per Year				8,760	

				Variable	Value
II.	**Annual Carrying Charge Rates**				
		Fixed Costs			10.8%
		O&M			4.8%
		Carrying Costs		**CC**	**15.5%**
III.	**Charges**				
		Contingencies			5%
		Stores Expense			26%
		Total Charges on Material		**MC**	**31%**
		Labor			56%
		Transportation Expense			22%
		Total Charges on Labor		**LC**	**78%**
IV.	**Overheads**				
		Company Construction Overheads		**OC**	**23%**

V. **Monthly Charge on Incremental Material**

IM = Incremental Material Cost
IL = Incremental Labor Cost (50% of Material) = 0.5 x IM

$$\boxed{Monthly\,Charge\ on\ IM = (1+OC)\times[(1+MC)\times IM + (1+LC)\times IL]\times\frac{CC}{12}}$$

Monthly Charge on IM = **3.50%** of Incremental Material Cost

VI. **Monthly Meter Charges**

		Incremental Material (IM)	Monthly Charge 3.50%		Average Charge
Standard Measurement					
Single Phase					
	Option 2 - Primary - Transformer Rated	391	$13.69		
	Option 2 - Secondary - Self-Contained	38	1.33		
	Option 3 - Primary - Transformer Rated	391	13.69		
	Option 3 - Secondary - Transformer Rated	391	13.69		
	Option 3 - Secondary - Self Contained	38	1.33		
Total			$ 43.73	/ 5 =	$8.75
				Use:	**$9.25**
				current	9.25
Polyphase					
	Option 2 - Primary - Transformer Rated	391	$13.69		
	Option 2 - Secondary - Self-Contained	230	8.05		
	Option 3 - Primary - Transformer Rated (or Sec. >200 Amps)	391	13.69		
	Option 3 - Secondary - Transformer Rated (Below 200 Amps)	391	13.69		
	Option 3 - Secondary - Self Contained (Below 200 Amps)	230	8.05		
Total			$ 57.17	/ 5 =	$11.43
				Use:	**$12.10**
				current	12.1
Time-of-Day Measurement					
Single Phase					
	Option 2 - Primary - Transformer Rated	400	$14.00		
	Option 2 - Secondary - Self-Contained	96	3.36		
	Option 3 - Primary - Transformer Rated	400	14		
	Option 3 - Secondary - Transformer Rated	400	14		
	Option 3 - Secondary - Self Contained	38	1.33		
Total			$ 46.69	/ 5 =	$9.34
				Use:	**$9.85**
				Current	9.85
Polyphase					
	Option 2 - Primary - Transformer Rated	400	$14.00		
	Option 2 - Secondary - Self-Contained	239	8.37		
	Option 3 - Primary - Transformer Rated	400	14		
	Option 3 - Secondary - Transformer Rated	400	14		
	Option 3 - Secondary - Self Contained	239	8.37		
Total			$58.74	/ 5 =	$11.75
				Use:	**#REF!**

Calculation of Meter O&M Expense as a % of Original Cost (Per Books Total Company Values)

Account 586 - Operation	1,178,553
Account 597 - Maintenance	30,845
Total O&M	1,209,398
Account 370 - Meter Plant	25,427,337
O&M Percentage	4.8%

KENTUCKY POWER COMPANY — P.S.C. KY. NO. 13 ORIGINAL SHEET NO. 36-1
CANCELLING P.S.C. KY. NO. 12 ORIGINAL SHEET NO. 36-1

Federal Tax ~~Cut~~ Change Tariff
(F.T.C.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., ~~C.S. Coal,~~ M.W., O.L., and S.L.

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023~~0~~-00159~~74~~, Kentucky Power Company is to credit to retail ratepayers the approved annual amount of excess accumulated deferred federal income taxes (ADIT) beginning January XX~~14~~, 2024~~1 at the rates set forth below and continue to do so until the Company's base rates are re-set in a future base rate proceeding~~.

2. The Company shall amortize the~~–~~ calendar year retail Generation and Distribution related ~~ARAM of~~ Protected Excess ADIT of $1,678,164 ~~and the amount of retail Generation and Distribution related Unprotected Excess ADIT needed~~ to support the ~~remainder of the actual calendar year~~ rate credits provided to customers through this ~~rider~~tariff.

3. Beginning with the October 2024 Federal Tax Change Tariff adjustment filing, the actual Corporate Alternative Minimum Tax (CAMT) expense and credits for the prior calendar/tax year shall be included in the Annual Revenue Requirement based on the Company's actual 2023 federal income tax return. This methodology will continue on a year to year basis.

4. For purposes of computing over or under-recovery under this tariff, the Company shall include the actual CAMT expense and the actual CAMT credits at the time that the credits can be used.

5. The Company shall include a final reconciliation of the retail Generation and Distribution related Unprotected Excess ADIT as part of the over or under-recovery computation in the October 2024 Federal Tax Change Tariff adjustment filing.

~~2.~~

~~3.~~6. The applicable rates~~Residential rate credits and All Other rate credits shall be credited to customers~~ on a kWh basis are as follows:

	Residential ($/kWh)	All Other ($/kWh)
~~January-March and December~~	$(0.00053)~~2187~~	$(0.00037)~~672~~
~~April-November~~	~~$0.00010~~	~~$0.00672~~

~~The Residential rate credit will end the earlier of December 31, 2023 or the billing month when the $30 million credit for Residential customers is calculated to be distributed in full. The All Other rate credit will end the earlier of December 31, 2023 or the billing month when the $10 million credit for All Other customers is calculated to be distributed in full. The rates set forth above may be adjusted in their final billing month to reconcile the amounts distributed to the $30 million credit available for distribution to Residential customers and the $10 million credit available for distribution to All Other customers.~~

~~4.~~7. The allocation of the Annual Revenue Requirement (ARR) which consists of the ~~actual~~ retail Generation and Distribution related ~~ARAM of~~ Protected Excess ADIT, the actual CAMT expenses and credits and any over or under-recovery based upon actual information for prior periods ~~Commission authorized amount of Unprotected Excess ADIT,~~ between residential and all other customers shall be based upon their respective contribution to total retail revenues, according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{AC(y)} \times \frac{\text{KY Residential Retail Revenue RR}}{\text{KY Retail Revenue R}}$$

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

All Other Allocation OA(y) = AC(y) x $\frac{\text{KY All Other Classes Retail Revenue OR}}{\text{KY Retail Revenue R}}$

Where:

(y)	=	the credit year;
RR	=	$301,523,011~~248,770,246~~;
OR	=	$392,479,515~~279,559,942~~; and
R	=	$694,002,526~~528,330,188~~.

8. The annual Federal Tax Change Tariff adjustments shall be filed with the Commission no later than October 15th of each year before it is scheduled to go into effect on Cycle 1 of the December billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

9. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Distribution Reliability Rider
(D.R.R.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S. Secondary and Primary, S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S. Secondary and Primary, L.G.S.-T.O.D. Secondary and Primary, I.G.S. Secondary and Primary, C.S. – I.R.P. Secondary and Primary, and M.W.

Rate
The Distribution Reliability Rider will apply to all customers served at secondary and primary voltages excluding customers receiving service under Tariffs O.L. and S.L. The Annual Distribution Reliability Net Costs to be recovered through this rider will be calculated on a per bill basis using the following formula:

1. Annual Distribution Reliability Net Costs (ADRNC)

ADRNC = ERW + ATL + DACRR + ANDSS + ARSHR

Where:

a. ERW = targeted widening of primary distribution circuits.

b. ATL = the cost of constructing primary lines to tie two circuits together to permit electrical load to be transferred.

c. DACRR = the costs of installing automation equipment to allow for the isolation of a fault and reconfiguration of the circuit to close other devices to re-energize the non-impacted areas of original circuit impacted by the initial fault and the recloser devices upgrade from three-phase to single-phase to allow for future DACR implementation, closure via electronics, event recordings and power quality investigations, and more precise coordination with other devices.

d. ANDSS = the costs of new distribution substations in remote areas with associated transmission lines in and out to reduce the number of radial distribution circuits and reduce outage times.

e. ARSHR = the costs of targeted facilities projects to renew and improve cable, conductor, hardware, and equipment to reduce feeder-level outages.

f. Subparts a through e include the capital expenditure and operations and maintenance to support that capital to enhance customer reliability.

2. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2021-00159 dated ________ as filed and approved by the Commission, Kentucky Power Company is to recover from its retail customers the costs associated with the Distribution Reliability Work Plan including vegetation management and other targeted investments to maintain and improve reliability.

Continued on Sheet 34-2

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Distribution Reliability Rider Continued
(D.R.R.)

3. The allocation of the ADRNC between residential and all other customers shall be based upon their respective contribution to total non-fuel retail revenues for the most recent twelve-month period, ending December 31 according to the following formula:

$$\text{Residential Allocation(y)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Classes Allocation(y)} = \frac{\text{KY All Other Classes Non-Fuel Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(y)	=	the expense year;
(b)	=	most recent available twelve month period ended December 31;.
RR	=	$XXX;
OR	=	$XXX; and
R	=	$XXX.

4. The rate will be calculated according to the following formula:

$$\text{Residential Factor} = \frac{\text{Residential Allocation x ADRNC}}{\text{Number of Residential Bills}}$$

$$\text{All Other Classes Factor} = \frac{\text{All Other Classes Allocation x ADRNC}}{\text{Number of All Other Classes Bills}}$$

5. The applicable rates for service rendered on and after _________, calculated in accordance with the above, is:

$$\text{Residential Factor} = \frac{\$XXX}{XXX} = \$X/\text{bill}$$

$$\text{All Other Classes Factor} = \frac{\$XXX}{XXX} = \$X/\text{bill}$$

All Other Classes excludes Tariffs O.L. and S.L. and all customers receiving service at subtransmission and transmission voltage levels.

6. The annual Distribution Reliability Rider adjustments shall be filed with the Commission no later than February 15th of each year before it is scheduled to go into effect Cycle 1 of April billing, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Securitization Financing Rider
(S.F.R.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L..

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to recover from retail ratepayers the costs approved for securitization by the Commission.

   This rider is designed to recover from customers the amounts necessary to service, repay and administer customer-backed bonds associated with the approved securitized costs pursuant to the terms of the financing order of the Kentucky Public Service Commission in Case No. 202#-#####.

   This rider shall remain in effect until the complete repayment and retirement of any customer-backed bonds, or refunding bonds, associated with the approved securitized costs. This schedule is irrevocable and nonbypassable for the full term during which it applies.

   The applicable rates for service rendered on and after XXXXXXXXX ##, 202# to be applied to the revenues described in paragraph 5 of this tariff are:

$$\text{Residential Adjustment Factor} = \frac{\$X}{\$X} = X.X\%$$

$$\text{All Other Classes Adjustment Factor} = \frac{\$X}{\$X} = X.X\%$$

2. The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve-month period ending December 31 or June 30, according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{ARR(y)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(y)} = \text{ARR(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(y) = the expense year;
(b) = Most recent available twelve month period ended December 31 or June 30.

Continued on Sheet 35-2

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Securitization Financing Rider Continued
(S.F.R.)

3. The Residential S.F.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential S.F.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation NRA(y)}}{\text{Residential Retail Revenue RR(b)}}$$

Where:

Net Annual Residential Allocation NRA(y)	=	Annual Residential Allocation RA(y), net of Over/(Under) Recovery Adjustment;
Residential Retail Revenue RR(b)	=	Annual Retail Revenue for all KY residential classes for the year (b).

~~1.~~4. The All Other Classes S.F.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes S.F.R. Adjustment Factor} = \frac{\text{Net Annual All Other Allocation NOA(y)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(b)}}$$

Where:

Net Annual All Other Allocation NOA(y)	=	Annual All Other Allocation OA(y), net of Over/(Under) Recovery Adjustment;
All Other Classes Non-Fuel Retail Revenue ONR(b)	=	Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b).

5. The Revenues to which the residential Securitization Financing Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Residential Energy Assistance, Purchase Power Adjustment and Distribution Reliability Rider.

   The Revenues to which the all other customer Securitization Financing Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Kentucky Economic Development Surcharge, Purchase Power Adjustment and Distribution Reliability Rider.

6. The initial Securitization Financing Rider rates shall be file on the day following the pricing of the bonds and shall become effective the first billing cycle following the closing of the bonds. All subsequent Rider rate adjustments shall be semi-annual (every six months).

   The semi-annual Securitization Financing Rider adjustments shall be filed with the Commission no later than February 15 and August 15th of each year before it is scheduled to go into effect on Cycle 1 of the April and October billing cycles, respectively, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

   Interim Securitization Financing Rider adjustments may be filed with the Commission outside of the standard semi-annual timeframe in order to correct for over- or under-collection to be submitted no later than 10 days before the rate is to be effective.

~~2.~~ Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER COMPANY

Securitization Financing Rider

Summary

Year Ended: **Month, Day, Year**

Residential S.F.R. Adjustment Factor	=	$15,892,408 / $272,909,708	=	5.8233%
All Other Classes S.F.R. Adjustment Factor	=	$21,169,089 / $185,044,772	=	11.4400%

Effective Date for Billing: Month, Day, Year
(1st Billing Cycle of October)

Submitted by: /s/ Brian K. West
(Signature)

Title: Vice President Regulatory & Finance

Date Submitted: Month, Day, Year

KENTUCKY POWER COMPANY

Securitization Financing Rider

Year Ended: Month, Day, Year

Residential Adjustment Factor

A.	Base Residential Allocation	=	$37,061,497	x	$ 272,909,708.35 / $ 636,432,332.99	*	=	$ 15,892,408
B.	Adjustment Factor	=	NRA (from A above) / Residential Retail Revenue	=	$15,892,408 / $272,909,708			5.8233%

All Other Adjustment Factor

C.	Base All Other Allocation	=	$37,061,497	x	$363,522,625 / $636,432,333	*	=	$ 21,169,089
D.	Adjustment Factor	=	NOA (from A above) / All Other Classes, Non-Fuel Retail Revenue	=	$21,169,089 / $185,044,772			11.4400%

Kentucky Power Securitization Analysis
20-Year Securitization

Tenor	**20**	**Years**				
Securitization Amount	**440,389,797**	**Payments**	**40**	**NPV Payments**	**$**	**349,314,721**
		Interest Rate	**5.166%**	**NPV Ongoing**	**$**	**9,413,508**
Upfront Costs	**$ 6,310,203**	**P&I**	**18,044,477**	**Total**	**$**	**358,728,229**
Total Securitized	**446,700,000**	**Discount Rate**	**8.3000%**			

Period	**Beg. Balance**	**Payment**	**Interest**	**Principal**	**End Balance**	**NPV Payments**	**Ongoing Costs**	**NPV Ongoing Costs**	**Total Monthly Payment of Debt Service And Ongoing Costs**
1	446,700,000	18,044,477	11,538,261	6,506,216	440,193,784	$ 17,325,470	$ 486,272	$ 466,895	$ 18,530,748
2	440,193,784	18,044,477	11,370,205	6,674,271	433,519,513	$ 16,635,113	$ 486,272	$ 448,291	$ 18,530,748
3	433,519,513	18,044,477	11,197,809	6,846,668	426,672,845	$ 15,972,264	$ 486,272	$ 430,429	$ 18,530,748
4	426,672,845	18,044,477	11,020,960	7,023,517	419,649,328	$ 15,335,827	$ 486,272	$ 413,278	$ 18,530,748
5	419,649,328	18,044,477	10,839,542	7,204,935	412,444,393	$ 14,724,750	$ 486,272	$ 396,810	$ 18,530,748
6	412,444,393	18,044,477	10,653,439	7,391,038	405,053,355	$ 14,138,022	$ 486,272	$ 380,998	$ 18,530,748
7	405,053,355	18,044,477	10,462,528	7,581,949	397,471,406	$ 13,574,673	$ 486,272	$ 365,817	$ 18,530,748
8	397,471,406	18,044,477	10,266,686	7,777,790	389,693,616	$ 13,033,771	$ 486,272	$ 351,241	$ 18,530,748
9	389,693,616	18,044,477	10,065,786	7,978,691	381,714,925	$ 12,514,423	$ 486,272	$ 337,245	$ 18,530,748
10	381,714,925	18,044,477	9,859,697	8,184,780	373,530,144	$ 12,015,769	$ 486,272	$ 323,807	$ 18,530,748
11	373,530,144	18,044,477	9,648,284	8,396,193	365,133,951	$ 11,536,984	$ 486,272	$ 310,904	$ 18,530,748
12	365,133,951	18,044,477	9,431,410	8,613,067	356,520,884	$ 11,077,277	$ 486,272	$ 298,516	$ 18,530,748
13	356,520,884	18,044,477	9,208,934	8,835,542	347,685,342	$ 10,635,887	$ 486,272	$ 286,621	$ 18,530,748
14	347,685,342	18,044,477	8,980,712	9,063,764	338,621,577	$ 10,212,086	$ 486,272	$ 275,200	$ 18,530,748
15	338,621,577	18,044,477	8,746,595	9,297,882	329,323,696	$ 9,805,171	$ 486,272	$ 264,235	$ 18,530,748
16	329,323,696	18,044,477	8,506,431	9,538,046	319,785,650	$ 9,414,471	$ 486,272	$ 253,706	$ 18,530,748
17	319,785,650	18,044,477	8,260,063	9,784,414	310,001,237	$ 9,039,338	$ 486,272	$ 243,597	$ 18,530,748
18	310,001,237	18,044,477	8,007,332	10,037,145	299,964,092	$ 8,679,153	$ 486,272	$ 233,890	$ 18,530,748
19	299,964,092	18,044,477	7,748,072	10,296,404	289,667,687	$ 8,333,320	$ 486,272	$ 224,570	$ 18,530,748
20	289,667,687	18,044,477	7,482,116	10,562,361	279,105,327	$ 8,001,268	$ 486,272	$ 215,622	$ 18,530,748
21	279,105,327	18,044,477	7,209,291	10,835,186	268,270,140	$ 7,682,446	$ 486,272	$ 207,030	$ 18,530,748
22	268,270,140	18,044,477	6,929,418	11,115,059	257,155,081	$ 7,376,329	$ 486,272	$ 198,781	$ 18,530,748
23	257,155,081	18,044,477	6,642,316	11,402,161	245,752,920	$ 7,082,409	$ 486,272	$ 190,860	$ 18,530,748
24	245,752,920	18,044,477	6,347,798	11,696,679	234,056,241	$ 6,800,200	$ 486,272	$ 183,255	$ 18,530,748
25	234,056,241	18,044,477	6,045,673	11,998,804	222,057,437	$ 6,529,237	$ 486,272	$ 175,953	$ 18,530,748
26	222,057,437	18,044,477	5,735,744	12,308,733	209,748,704	$ 6,269,071	$ 486,272	$ 168,942	$ 18,530,748
27	209,748,704	18,044,477	5,417,809	12,626,668	197,122,036	$ 6,019,271	$ 486,272	$ 162,210	$ 18,530,748
28	197,122,036	18,044,477	5,091,662	12,952,815	184,169,221	$ 5,779,425	$ 486,272	$ 155,747	$ 18,530,748
29	184,169,221	18,044,477	4,757,091	13,287,386	170,881,835	$ 5,549,136	$ 486,272	$ 149,541	$ 18,530,748
30	170,881,835	18,044,477	4,413,878	13,630,599	157,251,236	$ 5,328,023	$ 486,272	$ 143,582	$ 18,530,748
31	157,251,236	18,044,477	4,061,799	13,982,677	143,268,559	$ 5,115,720	$ 486,272	$ 137,861	$ 18,530,748
32	143,268,559	18,044,477	3,700,627	14,343,850	128,924,709	$ 4,911,877	$ 486,272	$ 132,368	$ 18,530,748
33	128,924,709	18,044,477	3,330,125	14,714,352	114,210,357	$ 4,716,157	$ 486,272	$ 127,093	$ 18,530,748
34	114,210,357	18,044,477	2,950,054	15,094,423	99,115,934	$ 4,528,235	$ 486,272	$ 122,029	$ 18,530,748
35	99,115,934	18,044,477	2,560,165	15,484,312	83,631,622	$ 4,347,801	$ 486,272	$ 117,167	$ 18,530,748
36	83,631,622	18,044,477	2,160,205	15,884,272	67,747,350	$ 4,174,557	$ 486,272	$ 112,498	$ 18,530,748
37	67,747,350	18,044,477	1,749,914	16,294,563	51,452,787	$ 4,008,216	$ 486,272	$ 108,015	$ 18,530,748
38	51,452,787	18,044,477	1,329,025	16,715,451	34,737,335	$ 3,848,503	$ 486,272	$ 103,711	$ 18,530,748
39	34,737,335	18,044,477	897,265	17,147,211	17,590,124	$ 3,695,154	$ 486,272	$ 99,579	$ 18,530,748
40	17,590,124	18,044,477	454,353	17,590,124	(0)	$ 3,547,916	$ 486,272	$ 95,611	$ 18,530,748

Big Run
Summary of EDR Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy		
(1)	Annual kWh		14,839,200
(2)	DA LMP $/kWh		0.04473
(3) =(1)*(2)	Marginal Costs - Energy		$663,689
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$267,807
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$27,177
	Summary of Incremental Costs and Revenues		
(7)	Energy		$663,689
(8)	Distribution		$27,177
(9)	PJM LSE Transmission		$233,426
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$924,293
(12)	Incremental Revenue	$	1,398,932
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**474,639**

Cyber Innovation - Long Fork
Summary of EDR Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy		
(1)	Annual kWh		108,324,000
(2)	DA LMP $/kWh		0.04473
(3) =(1)*(2)	Marginal Costs - Energy		$4,844,836
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$267,807
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$27,177
	Summary of Incremental Costs and Revenues		
(7)	Energy		$4,844,836
(8)	Distribution		$27,177
(9)	PJM LSE Transmission		$1,595,611
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$6,467,624
(12)	Incremental Revenue	$	7,328,081
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**860,457**

Dajcor
Summary of EDR Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy		
(1)	Annual kWh		4,105,500
(2)	DA LMP $/kWh		0.04473
(3) =(1)*(2)	Marginal Costs - Energy		$183,620
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$267,807
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$27,177
	Summary of Incremental Costs and Revenues		
(7)	Energy		$183,620
(8)	Distribution		$27,177
(9)	PJM LSE Transmission		$95,024
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$305,821
(12)	Incremental Revenue	$	528,042
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**222,220**

Discover AI
Summary of EDR Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy		
(1)	Annual kWh		94,752,000
(2)	DA LMP $/kWh		0.04473
(3) =(1)*(2)	Marginal Costs - Energy		$4,237,823
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$267,807
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$27,177
	Summary of Incremental Costs and Revenues		
(7)	Energy		$4,237,823
(8)	Distribution		$27,177
(9)	PJM LSE Transmission		$1,325,536
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$5,590,535
(12)	Incremental Revenue	$	6,290,414
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**699,878**

6/2020 - 12/2020

Special Contract
Summary of Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy		
(1)	Annual kWh		53,472,000
(2)	DA LMP $/kWh		0.02163
(3) =(1)*(2)	Marginal Costs - Energy		$1,156,717
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$0
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$0
	Summary of Incremental Costs and Revenues		
(7)	Energy		$1,156,717
(8)	Distribution		$0
(9)	PJM LSE Transmission		$800,978
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$1,957,695
(12)	Incremental Revenue	$	2,572,214
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**614,519**

1/2021 - 12/2021

Special Contract

Summary of Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy		
(1)	Annual kWh		119,736,000
(2)	DA LMP $/kWh		0.03989
(3) =(1)*(2)	Marginal Costs - Energy		$4,775,850
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$0
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$0
	Summary of Incremental Costs and Revenues		
(7)	Energy		$4,775,850
(8)	Distribution		$0
(9)	PJM LSE Transmission		$1,835,766
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$6,611,615
(12)	Incremental Revenue	$	5,662,839
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**(948,776)**

1/2022 - 12/2022

Special Contract
Summary of Incremental Costs and Revenues

Ln No.			
	Marginal Costs - Energy		
(1)	Annual kWh		136,536,000
(2)	DA LMP $/kWh		0.07258
(3) =(1)*(2)	Marginal Costs - Energy		$9,909,913
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$0
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$0
	Summary of Incremental Costs and Revenues		
(7)	Energy		$9,909,913
(8)	Distribution		$0
(9)	PJM LSE Transmission		$1,930,886
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$11,840,800
(12)	Incremental Revenue	$	6,799,518
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**(5,041,282)**

1/2023 - 5/2023

Special Contract
Summary of Incremental Costs and Revenues

Ln No.	Marginal Costs - Energy		
(1)	Annual kWh		45,216,000
(2)	DA LMP $/kWh		0.03186
(3) =(1)*(2)	Marginal Costs - Energy		$1,440,432
	Marginal Costs - Distribution		
(4)	Distribution WO Total		$0
(5)	Levelized Carrying Cost		10.15%
(6) =(4)*(5)	Annual Dist Incremental Cost		$0
	Summary of Incremental Costs and Revenues		
(7)	Energy		$1,440,432
(8)	Distribution		$0
(9)	PJM LSE Transmission		$643,629
(10)	Generation Capacity		$0
(11) =(7)+(8)+(9)+(10)	Total Incremental Costs		$2,084,061
(12)	Incremental Revenue	$	2,187,099
(13) =(12)-(11)	**Net Revenue (Cost)**	**$**	**103,038**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2023-00159
Regulatory Assets And Liabilities; (4) A	)	
Securitization Financing Order; And (5) All Other	)	
Required Approvals And Relief	)	

DIRECT TESTIMONY OF

KATHARINE I. WALSH

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
KATHARINE I. WALSH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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DIRECT TESTIMONY OF
KATHARINE I. WALSH ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Katharine I. Walsh. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation ("AEPSC") as Director, Regulatory Pricing & Analysis. AEPSC is a wholly-owned subsidiary of American Electric Power Company Inc. ("AEP"), the parent Company of Kentucky Power Company ("Kentucky Power" or the "Company").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Xavier University with a Bachelor of Science degree in economics in 2008. In 2008, I joined AEPSC as an Energy Analyst in the Commercial Operations Group. This role included various positions in Commercial Operations. In 2010, I transferred to Regulatory Services as a Regulatory Analyst. In 2019, I was promoted to Manager-Regulated Pricing & Analysis. In 2022, I was promoted to my current position.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include the oversight and preparation of cost-of-service analyses, rate design, special contracts, and other regulatory support as required for the AEP system operating companies.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDING?

A. Yes. I have presented testimony on behalf of the AEP operating companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky and Tennessee. In Kentucky, I presented testimony in Case No. 2017-00179 on behalf of the Company.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY ON THIS PROCEEDING?

A. The purpose of my testimony is to support the Kentucky Power jurisdictional cost-of-service study through which the cost to provide service to the Company's retail customers is developed. A copy of the Kentucky Power jurisdictional cost-of-service study is included in Section V of the Company's application. Additionally, I support certain operation and maintenance expense and operating revenue adjustments detailed in Section V, Exhibit 2.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes, I am sponsoring the following schedules filed with the Company's Application:

- Section V, Schedule 3 – Capitalization;
- Section V, Schedule 4 – Jurisdictional Cost-of-Service;
- Section V, Schedule 5 – Jurisdictional Cost-of-Service Adjustments;

- Section V, Schedule 6 – Electric Operation & Maintenance Expense;
- Section V, Schedule 7 – Energy & Capacity Charges;
- Section V, Schedule 8 – Monthly Book Credits;
- Section V, Schedule 9 – KPCO Demand Allocation Factors; and
- Section V, Schedule 10 – KPCO Energy Allocation Factors.

I am also sponsoring Section II, Exhibit L of the Application – Reconciliation – Rate Base and Capitalization.

IV. COST-OF-SERVICE STUDY OVERVIEW

Q. WHAT IS THE SOURCE OF THE DATA USED IN THE COMPANY'S JURISDICTIONAL COST-OF-SERVICE STUDY?

A. The Company follows the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC") and adopted by the Public Service Commission of Kentucky ("Commission"). The Uniform System of Accounts sets the guidelines for recording assets, liabilities, income and expenses into various accounts. The costs recorded in each FERC account are examined to verify compliance with these guidelines and may be adjusted to reflect the Commission's policies and known and measurable changes to the test year level of expenditures.

Q. HOW IS THE INFORMATION USED TO ALLOCATE COSTS TO KENTUCKY POWER'S RETAIL CUSTOMERS?

A. The costs recorded by FERC account are per book amounts pertaining to electric utility operations of the Company for service supplied to all customers, both wholesale and retail. Kentucky Power's retail revenue is approximately 99% of its total firm sales revenue. The Company's wholesale revenue, which includes sales to the cities of Olive Hill and Vanceburg, is approximately 1% of its total revenue. It is therefore necessary to identify and segregate costs related only to providing service to Kentucky Power's retail customers.

Q. EXPLAIN HOW THE REVENUE REQUIREMENT IS DETERMINED FOR KENTUCKY POWER'S RETAIL CUSTOMERS.

A. A three-step process is followed to assign and allocate costs to determine the total revenue requirement for the Company's retail customers. These three steps are (1) the functionalization of costs, (2) the classification of costs, and (3) the allocation of costs. By following this process, the Company is able to identify and segregate the costs related to providing service to Kentucky Power's retail customers.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. Once the data is gathered, the costs are then separated by functional group as follows:

1) Production and Purchased Power costs;
2) Transmission costs;
3) Distribution costs;
4) Customer Service costs; and
5) Administrative and General ("A&G") costs.

Q. PLEASE DESCRIBE EACH OF THESE FUNCTIONAL GROUPS.

A. The Production and Purchased Power functional group consists of the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The Transmission functional group consists of the costs associated with the high-voltage system utilized for the bulk transmission of power from generation sources to the load centers, and to and from interconnected utilities. The Distribution functional group consists of the radial distribution system that connects the transmission system and the ultimate customer. The Customer Service functional group encompasses the costs associated with providing meter reading, billing and collection, and customer information and services. Finally, the A&G functional group consists of all costs not directly assignable to other cost functions.

Q. PLEASE DESCRIBE THE CLASSIFICATION PROCESS.

A. Once costs have been segregated by functional group, the Company separates the costs within each functional group into separate classifications. The Company utilized the following classifications as part of its cost-of-service study: 1) demand costs (costs associated with the kilowatt demand imposed by the customer), 2) energy costs (costs that vary with the number of kilowatt hours used by the customer), 3) customer costs (costs that are directly related to the number of customers served) and 4) labor costs (costs that are directly related to payroll expenses associated with serving the customer). The Company classified costs within each functional group as follows:

Function	Classification
Production and Purchased Power costs	Demand, Energy
Transmission costs	Demand
Distribution costs	Demand, Customer
Customer Service costs	Customer
A&G costs	Labor

Production plant costs, such as depreciation and return on investment, are considered to be demand-related costs. Most fuel and production operation and maintenance

("O&M") expenses are energy-related because they vary with the quantity of energy produced. Transmission costs are demand-related because they are fixed and do not vary with energy usage. Generally, the distribution system costs are affected by either demand or by the number of customers served. Demand-related distribution costs will usually vary with the size of the load served, while customer-related distribution costs vary with the number of customers receiving the service. The classification process provides a basis on which to allocate different categories of costs (demand, energy or customer) to the utility's jurisdictions.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS.

A. Once the costs have been functionalized and classified, the third and final step is for the Company to allocate those costs between retail and wholesale customers based on how the costs are incurred for each. In other words, the allocation process assigns costs to customers subject to the Commission's jurisdiction (retail customers) or FERC's jurisdiction (wholesale customers). The allocation process employed by Kentucky Power is a reasonable, appropriate, and understandable method to assign costs as between the Company's retail and wholesale customer classes.

Some costs are directly assignable to a single jurisdiction. For example, costs related to regulatory deferrals are associated with a specific jurisdiction and are directly assigned to that jurisdiction. Most costs, however, are attributable to both jurisdictions. These are joint costs and must be allocated to the jurisdictions by an allocation methodology that is based on the classification described above for that cost.

Q. ARE THE ALLOCATION METHODS EMPLOYED BY THE COMPANY CONSISTENT WITH COST-OF-SERVICE PRINCIPLES?

A. Yes. The allocation methodologies utilized in the Company's jurisdictional cost-of-service study were chosen after giving consideration to cost causation principles. The results of the jurisdictional cost-of-service study can be relied upon to determine the appropriate revenue requirement for the Company's retail customers.

Q. ARE YOU RESPONSIBLE FOR THE METHODOLOGY USED IN THE PREPARATION OF THE KENTUCKY POWER JURISDICTIONAL COST-OF-SERVICE STUDY?

A. Yes. I developed the allocation methodology and the allocation factors used to calculate Kentucky Power's retail jurisdictional cost of service using the same process as in the Company's last rate case.

V. ALLOCATIONS

Q. PLEASE DESCRIBE HOW THE ENERGY ALLOCATION FACTOR ("EAF") WAS DETERMINED.

A. First, total retail customer test year sales of energy (in kilowatt hours) were accumulated. Next, the total sales of energy were adjusted to the generation level by applying the appropriate transmission and distribution loss factors to obtain the generation-level energy sales to retail customers. Finally, the retail generation-level sales were divided by the net total Company generation-level energy sales to obtain the retail EAF.

Q. PLEASE DESCRIBE HOW THE PRODUCTION DEMAND ALLOCATION FACTOR ("PDAF") WAS DETERMINED.

A. One basis for allocating the elements of the cost of property between retail and wholesale customers is the respective contribution by each of the two classes to the Company's peak demand. The PDAF reflects the coincident demand of the Company's retail customers at the time of Kentucky Power's monthly peak demand (the coincident peak demand). In other words, it represents the kilowatt contribution of retail customers to the Company's monthly peak demand.

The PDAF was calculated by dividing the average of the twelve monthly retail class coincident demands, adjusted for losses to the generation levels, by the average of the twelve monthly total Company internal peak demands. The transmission and sub-transmission demand allocation factors are the same as the PDAF.

The remaining allocators are internally calculated within the study and can be found in Section V, Allocation Factors.

Q. PLEASE DESCRIBE ANY ADJUSTMENTS MADE TO THE PDAF AND EAF ALLOCATORS.

A. No changes were made.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S ELECTRIC PLANT IN SERVICE.

A. Electric Plant in Service was separated into different plant categories by function and then allocated accordingly. Kentucky Power's production plant was allocated to the two jurisdictions using the PDAF. Transmission plant was allocated using the transmission demand allocation factor ("TDAF"). With the exception of Olive Hill substation and meter costs, which are wholesale costs, distribution plant was directly assigned to Kentucky Power's retail customers. General and intangible plant were allocated using gross plant production, transmission and distribution factor ("GP-PTD").

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION.

A. Kentucky Power's Accumulated Provision for Depreciation and Amortization were functionalized and classified in a fashion similar to Kentucky Power's Electric Plant in Service. Production, transmission, and distribution accumulated depreciation were allocated using the same process as the allocation of the associated plant. General and Intangible plant accumulated depreciation was allocated by GP-PTD factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S OTHER RATE BASE COMPONENTS.

A. Electric Plant held for Future Use, Construction Work in Progress, and Allowance for Funds Used during Construction were booked by functional group and then allocated using the associated plant factors. This is consistent with past treatment of these items.

Fuel and Allowance Inventory were allocated using the EAF. Materials and Supplies were separated into functional groups and allocated by associated plant factors accordingly. Materials and Supplies other components, such as lime, limestone, urea, and urea in-transit are allocated using the EAF. Prepayments were allocated using the gross plant total allocation factor ("GP-TOT").

Accumulated Deferred Investment Tax amounts were provided by Company Witness Schlessman. Customer Advances and Customer Deposits are a result of the Company's retail operations and, therefore, these amounts are allocated to Kentucky Power's retail cost-of-service. Any prepayments from non-retail customers were excluded from Kentucky Power's retail cost-of-service.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S OPERATING REVENUES.

A. Sales revenue was directly assigned to each jurisdiction where possible. Demand-related system sales revenue was allocated based on the PDAF. Energy-related system sales revenue was allocated on the EAF.

Forfeited Discounts and miscellaneous service revenues were a result of Kentucky Power's retail operations and therefore directly assigned 100% to the Company's retail customers.

Rent from electric property, other electric revenue, and various transmission agreement revenues were allocated to jurisdictions based on the corresponding functional allocator or directly assigned to Kentucky Power's retail customers where applicable.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S OPERATING AND MAINTENANCE EXPENSES.

A. Production-related O&M expenses were classified as either demand- or energy-related. The demand component was allocated using the PDAF and the energy component was allocated using the EAF.

Transmission-related O&M was allocated based on the gross plant transmission ("GP-TRANS") allocation factor or directly assigned as applicable.

Distribution-related O&M was allocated based on the gross plant distribution ("GP-DIST") allocation factor or directly assigned as applicable.

Customer Accounts, Customer Information, and Customer Service expenses were classified as customer-related and allocated on the total number of customers.

A&G expenses were allocated consistent with the allocation of non-A&G O&M expenses.

Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S DEPRECIATION AND AMORTIZATION EXPENSE.

A. Depreciation and Amortization were booked by functional group then allocated using the associated plant factors.

Q. PLEASE EXPLAIN HOW KENTUCKY POWER'S TAXES OTHER THAN FEDERAL AND STATE INCOME TAXES WERE ALLOCATED.

A. Taxes Other than Income Taxes were classified as relating to payroll, property, revenue, demand or energy and allocated accordingly or directly assigned. Payroll taxes are related to labor and allocated on the Operations and Maintenance Labor allocation factor ("OML"). Property taxes were allocated using the GP-TOT allocation factor.

Q. PLEASE EXPLAIN HOW KENTUCKY POWER'S FEDERAL AND STATE INCOME TAXES WERE ALLOCATED.

A. For details on Federal and State Income Taxes, please see Company Witness Schlessman's testimony and supporting tax schedules.

Q. PLEASE EXPLAIN HOW ADJUSTMENTS FOR KENTUCKY POWER'S TEST YEAR REVENUES AND OPERATING EXPENSES WERE INCORPORATED INTO SECTION V.

A. Adjustments to test year revenues and operating expenses were provided to me by way of individual worksheets compiled and prepared by various Company witnesses based on their expertise. I added the retail adjustments to the Company's retail per books cost-of-service amounts to arrive at the going-level Kentucky Power jurisdictional cost of service.

Q. PLEASE EXPLAIN ANY DIFFERENCES IN PRESENTATION, FROM PAST FILINGS, IN THE FORMAT OF THE COMPANY'S JURISDICTIONAL COST OF SERVICE STUDY.

A. There were no differences in the format of the Company's Jurisdictional Cost of Service Study.

Q. WERE THERE ANY DIFFERENCES IN THE METHODOLGY USED TO CALCULATE THE REVENUE REQUIREMENT IN THIS PROCEEDING?

A. Yes, I computed the revenue requirement utilizing Rate Base instead of Capitalization in this proceeding.

Q. PLEASE EXPLAIN THE DETERMINATION TO USE RATE BASE INSTEAD OF CAPITALIZATION.

A. The Company's base rate revenue requirement has historically been calculated utilizing a return on Capitalization methodology. In this case, the Company calculated the base rate revenue requirement utilizing a return on Rate Base instead of Capitalization consistent with the January 13, 2021 Order in Case No. 2020-00174.

Q. DESPITE THE CHANGE IN METHODOLOGY, HAVE YOU CONTINUED TO PREPARE AN ADJUSTED LEVEL OF CAPITALIZATION?

A. Yes. Section V, Schedule 3 presents adjusted Capitalization for comparison sake, as well as to establish the debt to equity ratios as utilized in determining the weighted average cost of capital (WACC).

VI. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.

A. The details of the revenue and operating expense adjustments are set forth on various pages of Section V, Exhibit 2 to the application. Specifically, I am sponsoring the following adjustments:

Adjustment	Exhibit Page No.
Adjustment to Remove Test Year Capacity Charge Revenues	W1
Adjust Test Year Off System Sales ("OSS") Margins	W7
Adjust OSS Margins to Exclude Rockport	W8
Year End Number of Customers Annualization	W13
Adjust Firm Sales for Normal Weather	W14
Adjust PJM LSE OATT Expense to Going Level	W23
Adjust KPSC Maintenance Assessment	W37
Surcharge Book to Bill Adjustment	W41
Book to Bill Adjustment	W42
Remove Federal Tax Cut Rider Revenues	W52

Remove Rockport Capacity Charge Revenues
(Section V, Exhibit 2, W1)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. In accordance with the Stipulation and Settlement Agreement approved by the Commission in Case No. 2004-00420, revenues associated with its Capacity Charge tariff ("tariff C.C.") are not to be used when designing rates in a general rate case proceeding. Accordingly, the Company has removed $4,242,329 in revenues received through tariff C.C. or booked as accounting deferrals from its test year revenue amounts.

Reset Off System Sales (OSS) Margins Baseline
(Section V, Exhibit 2, W7)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR OSS MARGINS.

A. The purpose of this adjustment is to include in the base rate cost of service only the test year level of OSS margins. The test year amount of OSS margins is $10,956,795.

Q. HOW WAS THIS ADJUSTMENT CALCULATED?

A. To adjust the base rate cost of service so that it only reflects the test year amount of OSS margins, two items must be accounted for:

1. System Sales Clause retail revenues; and
2. The deferral related to the System Sales Clause.

During the test year, the System Sales Clause credited $1,513,355 to customers because actual OSS margins were more than the amount included in base rates. This $1.5 million credit to retail revenues was removed from the base rate cost of service as part of this adjustment. During the test year, an accounting deferral relating to the System Sales Clause was recorded on the Company's books in the amount of 1,984,216. This amount was reversed as part of this adjustment to remove the test year deferral's effect on the base rate cost of service.

The net effect of these two items in Adjustment W7 is a $3,497,571 increase to the base rate cost of service and re-sets the base rate OSS margin credit level to $10,956,795.

Adjust OSS Margins to Exclude Rockport
(Section V, Exhibit 2, W8)

Q. PLEASE EXPLAIN THE SECOND ADJUSTMENT YOU MADE TO OSS MARGINS.

A. The purpose of this adjustment is to remove Rockport's contribution to the test year OSS margins as calculated in Adjustment W7.

Q. HOW WAS THIS FURTHER ADJUSTMENT TO OSS MARGINS CALCULATED?

A. This adjustment started with the test year level of OSS margins as calculated in W7 which resulted in a base rate OSS margin credit level of $10,956,795. This level was further reduced by $9,021,444 to establish the going forward level of base rate OSS margin credits. The $9,021,444 million reduction was determined by first evaluating the level of OSS volumes possible without Rockport generation. This analysis determined that only 18% of test year OSS volumes would have resulted if Rockport were no longer available to serve internal load and contribute to OSS. Applying 18%

to the test year base amount established in W7 results in the new base rate OSS margin credit level of $1,935,350.

Year-End Number of Customers Annualization
(Section V, Exhibit 2, W13)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR FIRM SALES REVENUE.

A. The purpose of the year-end customer annualization adjustment is to restate test year revenues and expenses to reflect, on an annual basis, changes in customers that occurred during the test year. For example, if the number of residential customers increased during the test year, per books residential kWh sales would have to be increased to reflect the impact of annualizing load growth that occurred within the test year. In addition to the revenue adjustment, test year variable operating expenses would also have to be increased or decreased to reflect the incremental costs associated with annualizing test year load growth or decline.

Q. HOW IS THE YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT CALCULATED?

A. The year-end customer annualization adjustment begins with the number of customers in each tariff class at the end of the historic test year and adds or subtracts usage from the test year amounts by the average amount of usage per customer. These adjusted billing units then calculate the new adjusted firm sales revenues for the various tariffs.

In addition to the impact on firm sales revenue, the year-end customer annualization adjustment reflects a change in variable operating expense that would also change based on load growth or decline. The year-end customer annualization adjustment increases firm sales revenues by $1,882,916 and increases operation and maintenance expense by $885,912.

Adjust Firm Sales for Normal Weather
(Section V, Exhibit 2, W14)

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT.

A. The purpose of the weather normalization adjustment is to restate test year revenues and expenses to reflect a 30-year average load for weather sensitive customers compared to the weather experienced during the test year. The Company bases its weather normalization on deviations from normal in both heating and cooling degree-days.

Using data provided by the Company's Economic Forecasting Group, the adjustment was calculated to increase test year energy usage to the level of the 30-year average. The result of this adjustment was to increase total usage by approximately 116.2 million kilowatt-hours and increase revenues by $12,333,767. The weather normalization adjustment also reflects the change in variable operating expense that the Company would experience based on this positive adjustment to test year load. Accordingly, this adjustment increases operation and maintenance expense by $5,803,037.

Adjust Test Year PJM LSE OATT Expense to Going Level
(Section V, Exhibit 2, W23)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF PJM LSE OATT EXPENSE.

A. The FERC-approved OATT includes rates and billing units that are different in 2023 than they were in 2022, and as a result, the test year PJM LSE OATT expense must be revised to account for these differences. This adjustment increases the Kentucky retail jurisdiction base rate cost of service by $14,214,861 for a total adjusted test year LSE OATT expense level of $136,358,812.

<u>KPSC Maintenance Fee Adjustment</u>
<u>(Section V, Exhibit 2, W37)</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF ADMINISTRATIVE & GENERAL EXPENSE.

A. This adjustment simply adjusts the test year amount of KPSC maintenance fee expense in the cost of service to the current assessment amount which is a decrease from the test year level. The result is a $29,109 decrease to test year expense levels.

<u>Surcharge Book to Bill Adjustment</u>
<u>(Section V, Exhibit 2, W41)</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. This adjustment accounts for the difference between the cost of service adjustments that remove various surcharges from the test year sales revenues and the billing analysis for the same surcharges. This adjustment reduces firm sales revenues by $364,641.

<u>Book to Bill Adjustment</u>
<u>(Section V, Exhibit 2, W43)</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. This adjustment compares the test year billing analysis for firm sales revenue and compares it to the test year income statement (books) level of firm sales revenue and adjusts the cost of service to the level supported by the billing analysis. In the sequence of revenue adjustments related to billing units, the book to bill adjustment is computed first and utilizes unadjusted test year billing units. This adjustment decreases test year firm sales revenue by $732,523.

Remove Federal Tax Cut Rider Revenues
(Section V, Exhibit 2, W52)

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR LEVEL OF SALES REVENUES.

A. Test year revenue credits resulting from the FTC rider are included in firm sales and need to be removed in order to arrive at the correct level of adjusted base rate revenues which are the subject of this case. The removal of the test year FTC rate credits increases firm sales revenue by $38,853,304.

VII. SECURITIZATION

Q. DID YOU PREPARE ANY CALCULATIONS IN SUPPORT OF THE SECURITIZATION PROPOSAL IN THIS PROCEEDING?

A. Yes. I calculated the Net Present Value ("NPV") of the return on the Accumulated Deferred Income Tax ("ADIT") liability associated with the Decommissioning Rider Regulatory Asset and the Rockport Deferral Regulatory Asset balances to be securitized and provided the amounts to Company Witness Messner. For this calculation, I utilized the 5.166% estimated securitization rate over a 20 year term which resulted in a NPV of $26,094,164 and $4,714,838 for the Decommissioning Rider Regulatory Asset and the Rockport Deferral Regulatory Asset, respectively.

Q. DID YOU ALSO PREPARE A SIMILAR CALCULATION FOR THE CONVENTIONAL METHODOLOGY PERFORMED BY COMPANY WITNESS MESSNER?

A. Yes. I calculated the NPV of the return on ADIT associated with the Decommissioning Rider Regulatory Asset balance to be $33,101,692 using the proposed pre-tax WACC of 8.30% over 17 years. This aligns with the current regulatory treatment of providing a credit at the Commission authorized pre-tax WACC return on ADIT in the Decommissioning Rider which would otherwise continue to apply over the next 17 years. Similarly, I calculated the NPV of the return on ADIT associated with the Rockport Deferral Regulatory Asset balance to be $1,946,928 using the proposed pre-tax WACC of 8.30% over 4.5 years. This aligns with the current regulatory treatment of providing a credit at the Commission authorized pre-tax WACC return on ADIT in Tariff P.P.A which would otherwise continue to apply over the next 4.5 years.

VIII. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Katharine I. Walsh, being duly sworn, deposes and says she is a Director of Regulatory Pricing and Analysis for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Katharine I. Walsh

Katharine I. Walsh

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Katharine I. Walsh, on June 21, 2023.

Scott E. Bishop

Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For (1) A General Adjustment Of Its Rates For	)	
Electric Service; (2) Approval Of Tariffs And Riders;	)	
(3) Approval Of Accounting Practices To Establish	)	Case No. 2023-00159
Regulatory Assets And Liabilities; (4) A	)	
Securitization Financing Order; And (5) All Other	)	
Required Approvals And Relief	)	

DIRECT TESTIMONY OF

JACLYN N. COST

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
JACLYN N. COST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT JNC-1	Class Cost-of-Service Study
EXHIBIT JNC-2	Revenue Allocation

DIRECT TESTIMONY OF
JACLYN N. COST ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Jaclyn N. Cost. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation ("AEPSC") as a Regulatory Consultant Principal. AEPSC is a wholly-owned subsidiary of American Electric Power Company Inc. ("AEP"), the parent Company of Kentucky Power Company ("Kentucky Power" or the "Company").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.

A. I received my Bachelor of Arts degrees in Accounting and Finance from Walsh University in 2013. I began my career as an Accountant for Innovative Mattress Solutions ("IMS") where I performed various reconciling duties for each of the company's retail stores. After IMS, I accepted a position with AEPSC in 2015 as an Accounting Associate within the Fuel department of Utility and Energy Accounting. My responsibilities included month-end accounting close as well as various reporting and contract review duties. I was promoted to Accountant before accepting a position as a Regulatory Consultant within Pricing and Analysis in August 2017. In April 2020

I was promoted to Regulatory Consultant Sr. and then promoted again in 2022 to my current role.

Q. WHAT ARE YOUR RESPONSIBILITIES AS REGULATORY CONSULTANT PRINCIPAL?

A. My responsibilities include preparing cost-of-service studies for regulatory filings and providing regulatory support and analysis for pricing matters associated with Kentucky Power and other AEP electric-utility operating companies.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony before the Public Service Commission of Kentucky in Case No. 2020-00174. In addition, I have submitted testimony before the State Corporation Commission of Virginia on behalf of Appalachian Power Company regarding cost-of-service.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support and describe the development of the Company's Class Cost-of-Service Study. In addition, I will address the allocation of the requested increase to Kentucky Power's customer classes.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. I am sponsoring the following exhibits:

Exhibit JNC-1	Class Cost–of-Service Study
Exhibit JNC-2	Revenue Allocation

IV. CLASS COST-OF-SERVICE STUDY

Q. PLEASE DESCRIBE THE GENERAL PURPOSE OF A CLASS COST-OF-SERVICE STUDY.

A. A class cost-of-service study is a basic analytical tool used in traditional utility rate design to determine the revenue requirement for the services offered by the utility. It analyzes, at a very detailed level, the costs that different classes of customers impose on the utility system. A class cost-of-service study calculates the total functional costs the Company incurs in serving each retail rate class as well as the rate of return on rate base earned from each class during the test year. This is accomplished by classifying and allocating the jurisdictional and functionalized costs of serving Kentucky's retail customers to the various rate classes. When a cost-of-service study is completed and all of the costs are allocated to the customer classes, the Company is able to establish rates based on the costs to serve each customer class. A copy of the class cost-of-service study prepared for this case is included as Exhibit JNC-1.

Q. WHAT DATA SOURCE WAS USED IN THE DEVELOPMENT OF THE CLASS COST-OF-SERVICE STUDY?

A. The Company's jurisdictional cost-of-service study, shown in Section V of this application and sponsored by Company Witness Walsh, is the primary data source for the class cost-of-service study. In addition, historic accounting records and Company data were used to derive the various allocators that were applied to the results of the jurisdictional cost-of-service study to classify and allocate costs to the customer classes.

Q. AFTER THE COSTS PRESENTED IN THE JURISDICTIONAL COST-OF-SERVICE STUDY ARE EXAMINED, HOW ARE THESE COSTS ASSIGNED TO EACH CUSTOMER CLASS?

A. These costs are assigned to the different customer classes in a way that reflects the costs of providing utility service to each class. The Company assigns costs to customer classes using a standard three-step process: functionalization of costs, classification of costs, and allocation of costs.

Q. PLEASE EXPLAIN THE FUNCTIONALIZATION PROCESS.

A. Functionalization is the process of separating costs according to electric system functions. Typically, functions in an electric utility include the following:

1) Production and Purchased Power costs;
2) Transmission costs;
3) Distribution costs;
4) Customer Service costs; and
5) Administrative and General ("A&G") costs.

The production function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of costs associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities to load centers of the utility's system. The distribution function includes the radial distribution system that connects the transmission system and the ultimate customer. The customer service function encompasses the costs associated with providing meter reading, billing and collection, and customer information and services. The A&G function is comprised of costs that may not be directly assignable to other cost functions. These costs include such items as management costs and administrative buildings. A&G costs are generally allocated to the remaining functions based on labor.

Q. PLEASE EXPLAIN THE CLASSIFICATION PROCESS.

A. The second step is to separate the functionalized costs into classifications of demand costs, energy costs, and customer costs.

Typical cost classifications used in cost studies include the following:

Function	Classification
Production	Demand, Energy
Transmission	Demand
Distribution	Demand, Customer
Customer Service	Customer

Demand costs are associated with the kilowatt ("kW") demand imposed by the customer. These are fixed costs, which are incurred regardless of the level of energy sales. An example of a demand-related cost is the investment in production, transmission or distribution facilities, such as a generating unit or transmission and distribution poles and lines.

Energy costs vary with the number of kilowatt-hours ("kWh") used by the customer. Production costs such as fuel and certain production operation and maintenance expenses are energy-related since they vary with the level of sales of electricity.

Customer costs are directly related to the number of customers served. These are fixed costs which are incurred regardless of the level of energy sales. Meter and customer service costs are examples of costs whose levels are fixed by the number of customers.

The classification process provides a basis on which to allocate different categories of costs (demand, energy, or customer) to the Company's classes. A&G costs are not classified but are generally allocated to the remaining functions based on labor.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS.

A. The third and final step is to allocate the functionalized and classified costs among the classes of customers based on how the costs are incurred to serve each class. Allocation factors are used to assign these costs to the various customer classes. Customer classes are determined and grouped according to the nature of service provided, voltage level, and the load usage characteristics. The three principal customer classes are residential, commercial, and industrial.

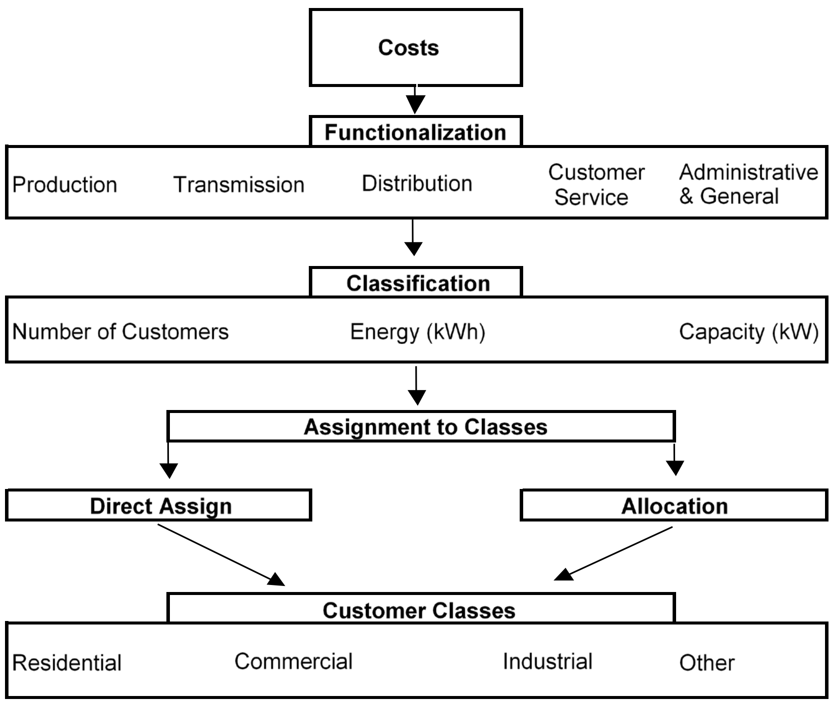
The allocation process involves multiplying the functionalized and classified costs by allocation factors, which results in costs assigned to each class. The objective in this process is to determine a reasonable, appropriate, and understandable method to assign the costs. Some costs are directly assignable to a single class, or even a single customer. For instance, the costs associated with the poles and luminaries used for street lighting are directly assigned to the street lighting class. Most costs, however, are attributable to more than one type of customer. These are joint costs that are allocated to customers by an allocation methodology that is based on the manner in which the costs are caused by the different customers.

The following flowchart (Figure JNC-1) provides an overview of how the allocation of costs to customer classes is determined.

Figure JNC-1

Figure 1:

Cost Allocation Example



In the illustration above, costs are functionalized into production, transmission, distribution, etc. Some of these costs can be functionalized and classified and directly assigned to a customer class. The remaining functionalized costs are incurred based on the number of customers, the energy used, or by the capacity demanded.

After functionalization, the next step is the classification process which leads to an allocation methodology. For example, the cost of billing customers varies with the number of customers as well as the complexity of preparing the customer's bill, so those costs associated with billing are allocated to the customer classes based on a weighted number of customers. An allocation factor using a weighted number of customers is developed by multiplying the number of customers in each class by a factor representing the difference in cost associated with providing that service to each customer class. Similarly, the cost of fuel varies by the number of kWh consumed and, therefore, is allocated based on the proportion of total energy used by a customer class.

The final step in the cost assignment process is to allocate the functionalized and classified costs to the customer classes through the use of allocation factors.

When this process is completed and all of the costs are allocated to the customer classes, the result is a fully allocated cost study that establishes cost responsibility, by class, and makes it possible to determine rates based on costs that are just and reasonable.

V. ALLOCATION BASIS

Q. WHAT CRITERIA ARE USED WHEN SELECTING ALLOCATION FACTORS FOR EACH FUNCTIONALIZED AND CLASSIFIED COST?

A. Generally, the following criteria are used to determine the appropriateness of an allocation methodology:

1) The method should reflect the planning and operating characteristics of the utility's system.

2) The method should recognize customer class characteristics such as energy usage, peak demand on the system, diversity characteristics, and number of customers, etc.

3) The method should produce stable results on a year-to-year basis.

4) The method should cause customers who benefit from the use of the system to bear appropriate cost responsibility for the system.

Q. DOES THE ALLOCATION METHOD EMPLOYED BY THE COMPANY MEET THESE OBJECTIVES?

A. Yes, it does. The allocation methodology utilized in the Company's class cost-of-service study is generally consistent with prior cases and reflects the consideration of each of the criteria listed above and the zero-intercept study sponsored by Company Witness Steward for allocation of distribution costs. The results of the cost-of-service study can be relied upon to determine the appropriate revenue requirement for the Kentucky Power customer classes. The allocation of specific sections of the class cost-of-service study, as shown on Exhibit JNC-1, follows.

Q. PLEASE EXPLAIN THE ALLOCATION OF PRODUCTION PLANT.

A. Electric plant-in-service is functionalized into production, transmission, distribution and general plant. Production plant is classified as demand-related and allocated using the production demand allocation factor. The production demand allocation factor assigns costs to the retail classes based on their average contribution to Kentucky Power's 12 coincident peaks ("CPs"). The CPs used in the allocation of Production Plant were the 12 monthly internal peak demands for the test period ended March 31, 2023.

Q. PLEASE EXPLAIN HOW GENERATOR STEP-UP TRANSFORMERS WERE ALLOCATED.

A. Generator step-up transformers are included in transmission plant but were allocated using the production demand allocation factor because they are more related to the production function.

Q. PLEASE EXPLAIN THE ALLOCATION OF TRANSMISSION PLANT.

A. Transmission plant, excluding generator step-up transformers, is classified as demand related and is allocated using the transmission demand allocation factor. The transmission demand allocation factor, similar to the production plant allocation factor, assigns costs based on the class average contribution to Kentucky Power's 12 CPs on the transmission facilities.

Q. PLEASE EXPLAIN THE ALLOCATION OF DISTRIBUTION PLANT.

A. Distribution plant is classified as demand/customer related and allocated to the customer classes using factors based on demand levels or number of customers. Distribution plant accounts 360 through 363 were classified solely as demand related. Accounts 360, 361, 362, and 363 were allocated to the distribution customer classes based on their contributions to the average of Kentucky Power's 12 monthly CP demands during the test year on the primary distribution system.

Accounts 364 through 368 were classified as demand and customer-related per the recommendation of Company Witness Steward following the results of the zero-intercept study as described in her testimony. The demand and customer-related percentages were derived from the results of the zero-intercept study. The demand-related percentages were further split into primary and secondary voltage functions based upon information contained in the zero-intercept study. The demand-related primary portions of accounts 364 through 368 were allocated using the average of 12 monthly CP demands on the distribution system. The demand-related secondary component of accounts 364 through 368 were allocated based on a combination of each class's 12-month maximum demand and the summation of individual customers' annual maximum demands in each class served from those facilities. This process reflects the fact that some secondary facilities serve only one customer, while others serve two or more customers.

Services, account 369, was classified as customer-related and was allocated using the average number of secondary customers served.

Meter plant, account 370, was allocated using the average number of customers weighted by a factor which considers the cost differential of various metering installations. Account 371 was directly assigned to the outdoor lighting class and account 373 was directly assigned to the street lighting class.

Q. PLEASE EXPLAIN HOW GENERAL AND INTANGIBLE PLANT WAS ALLOCATED.

A. General and intangible plant and investment reflects a composite demand, energy, and customer classification. General and intangible plant investment is allocated on the basis of payroll labor.

Q. PLEASE DESCRIBE THE ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION.

A. The functionalized components of Depreciation and Amortization were obtained directly from the jurisdictional cost-of-service study provided in Section V of the application. Production, transmission, distribution, and general and intangible related amounts were classified and allocated based upon the allocation of the corresponding functional Electric Plant-in-Service costs excluding land and land rights.

Q. PLEASE DESCRIBE THE ALLOCATION OF WORKING CAPITAL.

A. Working Capital was divided into cash, material and supplies, and prepayments. Cash working capital is related to operation and maintenance ("O&M") expense and was allocated based upon the allocation of total O&M expense less purchased power and fuel.

Materials and supplies were split between fuel stock, production, emissions, and transmission and distribution and were classified and allocated using the corresponding functional plant items. Fuel stock and emissions materials were allocated using the energy allocation factor. Production-related material and supplies were allocated using the production demand allocation factor, and the transmission- and distribution-related materials and supplies were allocated using the allocation of transmission and distribution electric plant-in-service.

Prepayments were allocated based upon gross utility plant.

Q. PLEASE DESCRIBE THE ALLOCATION OF OTHER RATE BASE COMPONENTS.

A. Plant Held for Future Use is limited to a distribution component that was allocated using distribution electric plant-in-service. Construction Work-in-Progress was functionalized and allocated by the corresponding functional Electric Plant-in-Service allocators. Accumulated Deferred Federal Income Tax was allocated on gross utility plant. Customer Deposits were directly assigned based on an analysis of accounting records, and Customer Advances were allocated based on transmission and distribution plant-in-service.

Q. HOW WERE REVENUES DEVELOPED FOR EACH CLASS?

A. Sales revenues were directly assigned to each class utilizing the revenue schedules in Section II – Application Filing Requirements Exhibit J, sponsored by Company Witness Spaeth. Energy-related system sales revenue was allocated using the energy allocation factor.

Forfeited Discounts and Miscellaneous Service Revenue were directly assigned based on an analysis of accounting records.

Rent from Electric Property and Other Electric Revenue were functionalized in the jurisdictional cost-of-service study and allocated to classes based on corresponding functional allocators.

Q. PLEASE DESCRIBE THE ALLOCATION OF PRODUCTION O&M EXPENSE.

A. Production-related O&M was classified as either demand or energy related. The demand component was allocated using the production demand allocation factor and the energy component was allocated using the energy allocation factor. Supervision and Engineering accounts for both O&M were classified and allocated based on functional labor expense. For example, Accounts 500 and 510 for Steam Production accounts were allocated on production labor expense.

Q. PLEASE DESCRIBE THE ALLOCATION OF TRANSMISSION O&M.

A. Transmission-related O&M was broken down into two pieces: expenses incurred through PJM as a Load Serving Entity (“LSE”), and the traditional transmission cost-of-service expenses recorded in FERC accounts 560 – 575. Most Transmission O&M expenses were allocated based upon the transmission demand allocation factor. Supervision and Engineering accounts for both O&M were classified and allocated based on functional labor expense. For example, Transmission Accounts 560 and 568 were allocated on total transmission O&M excluding PJM related costs. Expenses incurred through PJM as an LSE are classified as production expenses as they capture load LSE charges and are allocated using an allocation factor based on production demand.

Q. PLEASE DESCRIBE THE ALLOCATION OF DISTRIBUTION O&M AMONG THE VARIOUS CUSTOMER CLASSES.

A. Distribution O&M expenses were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Accounts 581 Load Dispatching and 582 Station Expenses were allocated using the distribution demand allocation factor. Account 583 Overhead Line Expense was allocated based upon the same allocation used for plant account 365 Overhead Lines. Account 584 Underground Line Expense was allocated based upon the same allocation used for plant accounts 366 Underground Conduit and 367 Underground Lines. Account 585 Street Lighting Operation Expense was classified as customer-related and directly assigned to the Street Lighting class. Meter Operation Expense, account 586, was classified customer-related and allocated in the same manner as account 370 Meter Plant. Account 587 Customer Installation Expense was classified as customer-related and allocated based on primary customers. Accounts 588 and 589 were allocated on total distribution plant and classified accordingly. Account 580 was classified and allocated based on the sum of the allocated O&M expense accounts 581 - 589. Accounts 591 and 592 were classified demand-related and allocated on the distribution demand allocation factor. Accounts 593, 594, and 595 were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Distribution maintenance account 596 was directly assigned to the Street Lighting class. Account 597 was classified customer-related and allocated in the same manner as meter plant. Account 598 was classified customer-related and directly assigned to the Outdoor Lighting class. Account 590 was classified and allocated based on the sum of the allocated O&M expense accounts 591 - 598.

Q. CAN YOU EXPLAIN HOW CUSTOMER ACCOUNTING (ACCOUNTS 901-905), CUSTOMER SERVICES (ACCOUNTS 907-910), AND SALES EXPENSE (ACCOUNTS 911-916) WERE ALLOCATED?

A. Account 902 Meter Reading Expense was allocated to those classes with meter installations based upon an average number of customers weighted to reflect varying levels of difficulty in meter reading. Account 903 Customer Records Expense was divided into two categories of cost; call center and other. Call center costs were first divided into residential and other based on the number of calls received; then, other (non-residential) call center expenses were further allocated to the remaining non-residential classes based on the number of customers in each respective class. Account 904 Uncollectibles was allocated based on the number of customers. Accounts 901 and 905 were allocated based on the sum of the allocated accounts 902, 903 and 904.

Accounts 907 through 916, Customer Service Expenses and Sales Expenses, were allocated based on the number of customers.

Q. PLEASE DESCRIBE THE ALLOCATION OF A&G EXPENSE.

A. A&G expenses, excluding Property Insurance, account 924, and Rate Case Expense, account 928, were functionalized, classified, and allocated using O&M labor. Property Insurance was allocated using gross utility plant. Rate Case Expense was allocated to the customer classes based on sales revenue.

Q. PLEASE DESCRIBE THE ALLOCATION OF DEPRECIATION AND AMORTIZATION EXPENSE.

A. The functionalized components of depreciation and amortization expense were allocated using the corresponding functional plant items excluding land and land rights.

Q. PLEASE DESCRIBE HOW OTHER EXPENSES WERE ALLOCATED.

A. The Gain on Disposition of Utility Plant was allocated based on distribution plant. A/R Factoring was allocated based on gross utility plant. Gain/Loss on Disposition of Allowances was allocated based on the energy allocation factor. Accretion was allocated on production demand. The Interest Income and Interest Expense items were allocated based on gross utility plant. Interest on Customer Deposits was allocated using the customer deposit allocator that was also used for the customer deposit rate base offset.

Q. HOW WERE TAXES ASSIGNED TO THE CUSTOMER CLASSES?

A. Individual tax items other than income taxes were allocated and classified using the appropriate revenue, labor, or plant allocator.

Interest Expense was allocated on rate base and individual Schedule M items were allocated using the appropriate allocators. State and current Federal Income Taxes were computed by class. Feedback of prior Investment Tax Credit Normalized was allocated based on gross utility plant and individual Deferred Federal Income Tax items were allocated using the appropriate allocation factors.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC") OFFSET.

A. The AFUDC offset was divided into the individual functionalized components in the jurisdictional cost-of-service study. The production component was allocated using the production demand allocator. The transmission and distribution components were allocated using the corresponding plant allocators. The general plant component was allocated using the labor allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE VARIOUS JURISDICTIONAL ADJUSTMENTS.

A. The jurisdictional adjustments are identified in the various sections of the cost-of-service study to which they apply. Each adjustment was allocated using a method consistent with both the nature of the adjustment and the underlying line item being adjusted. For example, an adjustment to employee-related expenses is allocated using the labor allocation factor, and an adjustment to the Mitchell Plant coal stock is allocated using the energy allocation factor.

VI. REVENUE ALLOCATION

Q. WHAT IS THE RESULTING GOING-LEVEL AND RELATIVE RATE OF RETURN FOR EACH CLASS SHOWN IN THE CLASS COST-OF-SERVICE STUDY?

A. The resulting going-level rates of return ("ROR") and relative rates of return prior to the rate relief requested in this case, for each customer class as shown in the class cost-of-service study, during the test year are presented in the table below. The going-level return is calculated from current income and rate base. The relative return provides a comparison to the total average Kentucky Power jurisdictional return. If the return earned on each class was the same as the average jurisdictional return, each would have a relative return of 1.00. A relative return less than 1.00 shows that the return earned from that class is less than the average return and that class is receiving a subsidy. A relative return greater than 1.00 shows that the return earned from that class is greater than the average and that customer class is paying a subsidy. A relative return of less than 0.00 indicates the customer class is not providing enough revenue to offset the expenses required to serve them and reduces the Company's overall return.

Figure JNC-2- Class Going-Level Rates of Return and Relative Rates of Return and Current Subsidy

CLASS	Going-Level ROR	Relative ROR	Subsidy (Paid)/ Received ($ in Millions)
Residential	0.75 %	.25	$31.9
General Service	6.44 %	2.13	($12.0.)
Large General Service	12.19 %	4.04	($15.1)
IGS	3.42 %	1.13	($1.7)
Municipal Waterworks	15.14 %	5.01	($0.05)
Outdoor Lighting	9.09 %	3.01	($2.4)
Street Lighting	14.10 %	4.67	($0.6)
Total Kentucky Power Jurisdiction	3.02 %	1.00	$0.0

Q. HOW ARE THESE RATES OF RETURN USED IN THIS PROCEEDING?

A. The going-level and relative rates of return for each class form the basis for the allocation of the revenue increase required for each class. This information was provided to Company Witness West to assist in his determination of the allocation of the requested rate increase by class.

Q. PLEASE EXPLAIN THE PRINCIPLES OR GUIDELINES USED IN ALLOCATING THE PROPOSED REVENUE INCREASE AMONG THE TARIFF CLASSES.

A. A key objective of ratemaking is to design rates such that they reflect as nearly as possible the actual costs of serving the customer. To fully meet this objective would require that the rates of return for all tariff classes be equalized. However, as indicated by Company Witness Spaeth, this would result in significant bill impacts to the

Residential customer class. As a result, the Company opted not to propose to fully equalize returns across tariff classes at this time, but rather proposes to continue its gradual progress toward cost alignment.

Q. PLEASE DESCRIBE EXHIBIT JNC-2.

A. Exhibit JNC-2 is the calculation of the allocation of the proposed revenue increase to each class of customers. Page 1 is a summary of the calculation of the required sales revenue per class based upon the Company's proposed subsidy reduction. Page 2 of the exhibit calculates the current subsidies received by each class. Page 3, in Columns 2 through 11, shows the calculation of the required sales revenue at an equalized ROR for each class before demonstrating that each class will retain its current subsidy.

Q. WHAT CLASS-BY-CLASS BASE RATE REVENUE INCREASE WILL RESULT FROM THE PROPOSED INCREASE?

A. Figure JNC-3 summarizes the Company's proposed revenue allocation, as sponsored by Company Witness West, between the major customer classes and the class rate increases:

Figure JNC-3- Base Rate Increase

CLASS	Proposed Increase ($ in Millions)	Percent Increase
Residential	$54.9	24.14%
General Service	$13.8	17.25%
Large General Service	$6.4	12.06 %
IGS	$17	12.87 %
Municipal Waterworks	$0.02	11.14 %
Outdoor Lighting	$1.6	19.44 %
Street Lighting	$0.2	14.75 %
Total Kentucky Power Jurisdiction	$93.9	18.69 %

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The class cost-of-service study, Exhibit JNC-1, has been developed in accordance with sound cost-of-service principles. The class cost-of-service study, along with the revenue allocation, submitted as Exhibit JNC-2, provide Company Witness Spaeth with functionalized revenue requirements that he can use to develop rates for the Company's customer classes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Jaclyn N. Cost, being duly sworn, deposes and says she is a Regulatory Consultant Principle for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Jaclyn N. Cost

Jaclyn N. Cost

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jaclyn N. Cost, on June 21, 2023.

Scott E. Bishop

Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Rate Base												
P-T-D Plant in Service												
Production Plant & Comp. Const. not Classif.	1,210,786,219	PROD_DEMAND	TOTAL	1,210,786,219	600,318,184	152,118,114	88,747,969	346,950,252	19,190,759	273,933	2,574,231	612,778
Transmission & Comp. Const. not Classif.												
GSU	12,793,807	PROD_DEMAND	TOTAL	12,793,807	6,343,279	1,607,360	937,758	3,666,060	202,780	2,895	27,201	6,475
All Other Transmission Plant	781,438,278	TRANS_TOTAL	TOTAL	781,438,278	384,952,262	97,497,240	56,863,162	228,050,904	12,279,255	175,395	1,308,589	311,471
Total	794,232,085		TOTAL	794,232,085	391,295,541	99,104,601	57,800,920	231,716,963	12,482,035	178,289	1,335,790	317,946
Distribution & Comp. Const. not Classif.												
360 Land and Land Rights	9,453,118	DIST_CPD	TOTAL	9,453,118	6,252,480	1,571,306	863,509	565,024	194,026	2,794	3,215	763
361 Structures and Improvements	9,335,686	DIST_CPD	TOTAL	9,335,686	6,174,808	1,551,786	852,782	558,005	191,616	2,760	3,176	754
362 Station Equipment	142,783,453	DIST_CPD	TOTAL	142,783,453	94,439,812	23,733,591	13,042,769	8,534,336	2,930,639	42,206	48,567	11,531
363 Storage Battery Equipment	-	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-	-
364 Poles	294,495,923	DIST_OHLINES	TOTAL	294,495,923	231,621,643	54,360,101	4,838,794	2,221,037	1,205,695	25,876	115,889	106,889
365 Overhead Lines	314,168,566	DIST_OHLINES	TOTAL	314,168,566	247,094,216	57,991,414	5,162,031	2,369,404	1,286,237	27,604	123,630	114,030
366 Underground Conduit	9,459,130	DIST_UGLINES	TOTAL	9,459,130	7,221,641	1,716,049	283,997	163,577	66,654	1,187	3,173	2,854
367 Underground Lines	12,829,684	DIST_UGLINES	TOTAL	12,829,684	9,794,915	2,327,525	385,193	221,864	90,405	1,609	4,303	3,870
368 Transformers	158,635,799	DIST_TRANSF	TOTAL	158,635,799	120,053,773	27,096,411	6,877,140	2,289,387	1,789,644	26,625	392,080	110,739
369 Services	74,228,381	DIST_SERV	TOTAL	74,228,381	44,914,796	10,518,298	128,172	1,364	47,042	2,727	18,597,575	18,408
370 Meters	25,427,337	DIST_METERS	TOTAL	25,427,337	11,487,291	10,263,063	1,777,390	1,638,114	237,481	23,998	-	-
371 Installations on Cust Premises	19,898,675	DIST_OL	TOTAL	19,898,675	-	-	-	-	-	-	19,898,675	-
373 Street Lighting	5,023,841	DIST_SL	TOTAL	5,023,841	-	-	-	-	-	-	-	5,023,841
Total	1,075,739,593		TOTAL	1,075,739,593	779,055,375	191,129,543	34,211,777	18,562,110	8,039,439	157,387	39,190,283	5,393,679
Total P-T-D Plant in Service	3,080,757,897		TOTAL	3,080,757,897	1,770,669,100	442,352,257	180,760,666	597,229,325	39,712,232	609,609	43,100,304	6,324,402
General & Intangible Plant & Comp. Const. not Classif.	162,064,920	LABOR_M	TOTAL	162,064,920	94,468,876	23,856,675	8,178,507	31,410,596	1,794,089	30,882	2,104,425	220,869
HR - J 765 Line - FERC AFUDC Adj.	367,952	BULK_TRANS	TOTAL	367,952	182,434	46,228	26,970	105,436	5,832	83	782	186
Total Electric Plant in Service	3,243,190,769		TOTAL	3,243,190,769	1,865,320,410	466,255,160	188,966,144	628,745,358	41,512,154	640,575	45,205,512	6,545,458
Adj 4 - Remove FGD from Base Rates (Mitchell)	(324,785,553)	PROD_DEMAND	TOTAL	(324,785,553)	(161,031,461)	(40,804,698)	(23,806,067)	(93,067,155)	(5,147,797)	(73,481)	(690,521)	(164,374)
Total Adjustments to Electric Plant in Service	(324,785,553)		TOTAL	(324,785,553)	(161,031,461)	(40,804,698)	(23,806,067)	(93,067,155)	(5,147,797)	(73,481)	(690,521)	(164,374)
Total Adjusted Electric Plant in Service	2,918,405,216		TOTAL	2,918,405,216	1,704,288,949	425,450,462	165,160,076	535,678,203	36,364,357	567,094	44,514,991	6,381,084
Depreciation Reserve												
Generation	(576,915,081)	RB_GUP-Land_P	TOTAL	(576,915,081)	(286,039,441)	(72,481,197)	(42,286,608)	(165,314,759)	(9,144,007)	(130,523)	(1,226,569)	(291,976)
Transmission - GSU	(139,329)	RB_GUP-Land_P	TOTAL	(139,329)	(69,080)	(17,505)	(10,212)	(39,925)	(2,208)	(32)	(296)	(71)
Transmission - All Other	(266,920,436)	RB_GUP-Land_T	TOTAL	(266,920,436)	(131,462,571)	(33,295,116)	(19,418,454)	(77,942,796)	(4,193,109)	(59,895)	(443,043)	(105,453)
Distribution	(329,767,156)	RB_GUP-Land_D	TOTAL	(329,767,156)	(238,998,542)	(58,623,395)	(10,317,163)	(5,568,507)	(2,427,126)	(47,819)	(12,117,054)	(1,667,548)
General & Intangible	(51,986,075)	RB_GUP-Land_G	TOTAL	(51,986,075)	(30,303,079)	(7,652,581)	(2,623,445)	(10,075,676)	(575,496)	(9,906)	(675,043)	(70,849)
HR-J Post In-Service AFUDC	(1,261,428)	BULK_TRANS	TOTAL	(1,261,428)	(625,427)	(158,481)	(92,460)	(361,462)	(19,993)	(285)	(2,682)	(638)
Total Depreciation Reserve	(1,226,989,505)		TOTAL	(1,226,989,505)	(687,498,141)	(172,228,273)	(74,748,342)	(259,303,125)	(16,361,940)	(248,461)	(14,464,687)	(2,136,535)
Adj 4 - Remove FGD from Base Rates (Mitchell)	150,195,274	PROD_DEMAND	TOTAL	150,195,274	74,468,104	18,869,906	11,008,984	43,038,389	2,380,570	33,981	319,328	76,014
Total Depreciation Adjustments	150,195,274		TOTAL	150,195,274	74,468,104	18,869,906	11,008,984	43,038,389	2,380,570	33,981	319,328	76,014
Total Adjusted Depreciation Reserve	(1,076,794,231)		TOTAL	(1,076,794,231)	(613,030,037)	(153,358,367)	(63,739,359)	(216,264,736)	(13,981,370)	(214,480)	(14,145,360)	(2,060,522)
Net Electric Plant in Service	1,841,610,985		TOTAL	1,841,610,985	1,091,258,911	272,092,095	101,420,718	319,413,466	22,382,987	352,613	30,369,631	4,320,563
Plant Held for Future Use - Tranmsission	-	RB_GUP_EPIS_T	TOTAL	-	-	-	-	-	-	-	-	-
Plant Held for Future Use - Distribution	800,870	RB_GUP_EPIS_D	TOTAL	800,870	579,994	142,293	25,470	13,819	5,985	117	29,177	4,016
Total Plant Held for Future Use	800,870		TOTAL	800,870	579,994	142,293	25,470	13,819	5,985	117	29,177	4,016
Working Capital												
Working Capital - Cash												
Working Capital Cash - Excl Sys Sales	7,686,462	EXP_OM_LPP	TOTAL	7,686,462	4,292,425	1,067,362	454,380	1,704,753	97,773	1,277	59,904	8,588
Total Working Capital - Cash	7,686,462		TOTAL	7,686,462	4,292,425	1,067,362	454,380	1,704,753	97,773	1,277	59,904	8,588

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Cash Working Capital Adjustments												
	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
	-	TDOMX	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
	-	TRAN_LSE	TOTAL	-	-	-	-	-	-	-	-	-
	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-
	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
	-	TOTOHLINES	TOTAL	-	-	-	-	-	-	-	-	-
	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-	-
	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
	-	CUST_903	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Total Cash Working Capital Adjustments	-		TOTAL	-	-	-	-	-	-	-	-	-
Working Capital - Materials & Supplies												
Fuel / Allowance Inventory	47,825,468	PROD_ENERGY	TOTAL	47,825,468	17,571,969	5,623,614	3,689,172	19,716,530	805,643	14,914	326,971	76,655
Production - Demand Related	8,976,804	PROD_DEMAND	TOTAL	8,976,804	4,450,776	1,127,808	657,980	2,572,299	142,281	2,031	19,085	4,543
Emissions - Energy Related	3,222,565	PROD_ENERGY	TOTAL	3,222,565	1,184,030	378,929	248,583	1,328,535	54,286	1,005	22,032	5,165
Transmission & Distribution	10,392,589	TDPLANT	TOTAL	10,392,589	6,504,098	1,612,950	511,421	1,391,268	114,060	1,866	225,188	31,738
Total Working Cap - Materials & Supplies	70,417,426		TOTAL	70,417,426	29,710,873	8,743,302	5,107,156	25,008,632	1,116,270	19,815	593,277	118,101
Working Capital - Materials & Supplies Adjustments												
Adj 4 - Remove FGD from Base Rates (Mitchell)	(1,844,518)	PROD_ENERGY	TOTAL	(1,844,518)	(677,710)	(216,890)	(142,283)	(760,421)	(31,072)	(575)	(12,611)	(2,956)
Adj 43 - Mitchell Coal Stock Adjustment	(16,290,160)	PROD_ENERGY	TOTAL	(16,290,160)	(5,985,308)	(1,915,498)	(1,256,594)	(6,715,782)	(274,416)	(5,080)	(111,372)	(26,110)
Total Working Cap - Materials & Supplies Adjustments	(18,134,678)		TOTAL	(18,134,678)	(6,663,019)	(2,132,388)	(1,398,877)	(7,476,203)	(305,487)	(5,655)	(123,983)	(29,066)
Working Capital - Prepayments												
Working Capital - Prepayments	42,213,175	RB_GUP_EPIS	TOTAL	42,213,175	24,651,631	6,153,914	2,388,952	7,748,300	525,991	8,203	643,886	92,299
Total Working Capital	102,182,385		TOTAL	102,182,385	51,991,910	13,832,190	6,551,611	26,985,481	1,434,546	23,640	1,173,084	189,922
Construction Work-In-Progress excluding AFUDC												
Production	17,920,164	RB_GUP_EPIS_P	TOTAL	17,920,164	8,884,971	2,251,414	1,313,509	5,135,015	284,032	4,054	38,100	9,069
Transmission	68,804,203	RB_GUP_EPIS_T	TOTAL	68,804,203	33,897,972	8,585,444	5,007,301	20,073,439	1,081,321	15,445	115,733	27,547
Distribution	42,608,696	RB_GUP_EPIS_D	TOTAL	42,608,696	30,857,406	7,570,401	1,355,086	735,222	318,432	6,234	1,552,278	213,637
General	6,420,988	RB_GUP_EPIS_G	TOTAL	6,420,988	3,742,843	945,198	324,031	1,244,483	71,082	1,224	83,377	8,751
Total CWIP	135,754,051		TOTAL	135,754,051	77,383,192	19,352,457	7,999,927	27,188,159	1,754,866	26,957	1,789,488	259,004
Adjustments to CWIP	(11,100,396)	RB_GUP_EPIS_P	TOTAL	(11,100,396)	(5,503,671)	(1,394,607)	(813,635)	(3,180,814)	(175,939)	(2,511)	(23,600)	(5,618)
Total Adjusted CWIP	124,653,655		TOTAL	124,653,655	71,879,521	17,957,850	7,186,292	24,007,346	1,578,927	24,446	1,765,888	253,386

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Rate Base Offsets												
Accumulated Deferred FIT	(349,208,256)	RB_GUP	TOTAL	(349,208,256)	(203,930,478)	(50,908,220)	(19,762,596)	(64,097,765)	(4,351,258)	(67,857)	(5,326,540)	(763,543)
Customer Advances	(1,024,491)	TDPLANT	TOTAL	(1,024,491)	(641,167)	(159,003)	(50,415)	(137,150)	(11,244)	(184)	(22,199)	(3,129)
Customer Deposits	(36,415,315)	CUST_DEP_FXNL	TOTAL	(36,415,315)	(23,777,649)	(5,575,945)	(2,141,475)	(4,770,756)	(29,326)	-	(120,164)	-
Adjustments to Rate Base Offsets												
Adj 4 - Remove FGD from Base Rates (Mitchell)	39,784,726	PROD_DEMAND	TOTAL	39,784,726	19,725,608	4,998,386	2,916,133	11,400,296	630,581	9,001	84,586	20,135
Adj 44 - Amortization of Excess	29,974,321	RB_GUP	TOTAL	29,974,321	17,504,390	4,369,711	1,696,324	5,501,837	373,491	5,824	457,204	65,539
Adj 62 - NOLC	41,506,654	RB_GUP	TOTAL	41,506,654	24,239,037	6,050,916	2,348,969	7,618,616	517,188	8,065	633,109	90,754
Adj 63 - NERC	392,385	RB_GUP	TOTAL	392,385	229,145	57,203	22,206	72,023	4,889	76	5,985	858
Adj 64 - CAMT & NERC	(770,063)	RB_GUP	TOTAL	(770,063)	(449,701)	(112,261)	(43,580)	(141,346)	(9,595)	(150)	(11,746)	(1,684)
Total Adjustments to Rate Base Offsets	110,888,023		TOTAL	110,888,023	61,248,479	15,363,955	6,940,052	24,451,426	1,516,553	22,818	1,169,138	175,602
Total Rate Base Offsets	(275,760,039)		TOTAL	(275,760,039)	(167,100,815)	(41,279,213)	(15,014,434)	(44,554,245)	(2,875,275)	(45,223)	(4,299,765)	(591,069)
Total Rate Base	1,793,487,856		TOTAL	1,793,487,856	1,048,609,520	262,745,215	100,169,657	325,865,868	22,527,171	355,593	29,038,015	4,176,817
Operating Revenues												
Year End Migration Revenue	488,449,955	RSALE	TOTAL	488,449,955	217,479,826	78,488,548	41,711,812	131,116,969	10,015,130	179,934	7,976,096	1,481,640
Adj 12 - Specific Customer Adjustment	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Adj 13 - Year End Customer Annualization	1,882,916	REVYEC_FXNL	TOTAL	1,882,916	(567,986)	206,225	832,006	1,484,148	94,035	(12,732)	(153,855)	1,075
Adj 14 - Weather Normalization Adjustment	12,333,767	WEATHER_FXNL	TOTAL	12,333,767	10,645,723	1,073,352	491,338	-	123,354	-	-	-
Total Firm Sales	502,666,638		TOTAL	502,666,638	227,557,563	79,768,125	43,035,156	132,601,117	10,232,519	167,202	7,822,241	1,482,715
Non-Firm Sales: Energy	45,625,370	PROD_ENERGY	TOTAL	45,625,370	16,763,612	5,364,913	3,519,461	18,809,518	768,581	14,228	311,930	73,128
Non-Firm Sales: Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adjs 8, 25 - Non-Firm Sales: Energy Adjustment - reset OSS ma	(9,021,444)	PROD_ENERGY	TOTAL	(9,021,444)	(3,314,647)	(1,060,797)	(695,898)	(3,719,181)	(151,971)	(2,813)	(61,677)	(14,460)
Total Sales of Electricity Adjustments	(9,021,444)		TOTAL	(9,021,444)	(3,314,647)	(1,060,797)	(695,898)	(3,719,181)	(151,971)	(2,813)	(61,677)	(14,460)
Sales of Electricity	539,270,564		TOTAL	539,270,564	241,006,528	84,072,241	45,858,719	147,691,453	10,849,130	178,616	8,072,493	1,541,384
Other Operating Revenues												
450-Forfeited Discounts	1,803,105	FORF_DISC_FXNL	TOTAL	1,803,105	(28,713)	771,768	334,245	721,338	-	-	4,467	-
451-Miscellaneous Service Revenue	158,579	MISC_SERV_REV	TOTAL	158,579	143,268	11,599	95	-	-	-	3,616	-
454x-Rent from Electric Prop - Poles	4,391,907	DIST_OHLINES	TOTAL	4,391,907	3,454,244	810,689	72,162	33,123	17,981	386	1,728	1,594
454x-Rent from Electric Prop - Production	895,952	RB_GUP_EPIS_P	TOTAL	895,952	444,221	112,564	65,671	256,735	14,201	203	1,905	453
454x-Rent from Electric Prop - Transmission	235,408	TRANS_TOTAL	TOTAL	235,408	115,967	29,371	17,130	68,700	3,699	53	394	94
454x-Rent from Electric Prop - Other Dist	1,371,566	RB_GUP_EPIS_D	TOTAL	1,371,566	993,294	243,690	43,620	23,667	10,250	201	49,968	6,877
456-Other Electric Revenue - Production Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
456-Other Electric Revenue - Transmission	85,002,297	TRANS_TOTAL	TOTAL	85,002,297	41,873,846	10,605,431	6,185,389	24,806,631	1,335,697	19,079	142,344	33,881
456-Other Electric Revenue - Dist	489,906	RB_GUP_EPIS_D	TOTAL	489,906	354,792	87,043	15,580	8,453	3,661	72	17,848	2,456
456-Other Electric LSE Charge	(52,004,092)	TRAN_LSE	TOTAL	(52,004,092)	(25,784,075)	(6,533,577)	(3,811,786)	(14,901,749)	(824,256)	(11,766)	(110,565)	(26,319)
456-Other Electric Revenues DSM	307,780	PROD_DEMAND	TOTAL	307,780	152,600	38,668	22,560	88,194	4,878	70	654	156
Total Other Operating Revenues	42,652,408		TOTAL	42,652,408	21,719,445	6,177,246	2,944,667	11,105,091	566,111	8,297	112,359	19,192
Other Operating Revenue Adjustments												
Adj ?? - DSM	(307,780)	PROD_DEMAND	TOTAL	(307,780)	(152,600)	(38,668)	(22,560)	(88,194)	(4,878)	(70)	(654)	(156)
Adj 50 - Replacement capacity	(6,321,080)	TRAN_LSE	TOTAL	(6,321,080)	(3,134,046)	(794,154)	(463,321)	(1,811,303)	(100,188)	(1,430)	(13,439)	(3,199)
Adj 52 - Rent from Electric Prop - Poles -CATV Adj.	4,266	DIST_OHLINES	TOTAL	4,266	3,355	787	70	32	17	0	2	2
Total Other Operating Revenue Adjustments	(6,624,594)		TOTAL	(6,624,594)	(3,283,290)	(832,035)	(485,811)	(1,899,465)	(105,049)	(1,499)	(14,092)	(3,353)
Total Other Operating Revenues	36,027,814		TOTAL	36,027,814	18,436,154	5,345,211	2,458,856	9,205,627	461,063	6,797	98,268	15,839
Total Operating Revenues	575,298,378		TOTAL	575,298,378	259,442,682	89,417,452	48,317,575	156,897,080	11,310,192	185,414	8,170,761	1,557,223
Operating Expense												
O&M Expense												
Production												
500-Supervision & Engineering	5,631,339	LABOR_PROD	TOTAL	5,631,339	2,525,331	690,774	420,743	1,874,826	91,324	1,452	21,759	5,128
501-Fuel Delivered and Consumed	104,685,268	PROD_ENERGY	TOTAL	104,685,268	38,463,319	12,309,541	8,075,237	43,157,554	1,763,474	32,644	715,708	167,790
502-Steam / Consumables	5,581,781	PROD_ENERGY	TOTAL	5,581,781	2,050,850	656,340	430,569	2,301,145	94,028	1,741	38,161	8,946
503-Steam other Sources	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
504-Steam Transferred Credit	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
505-Electric	93,523	PROD_DEMAND	TOTAL	93,523	46,370	11,750	6,855	26,799	1,482	21	199	47
506-Misc. Steam Power Expenses	5,816,320	PROD_DEMAND	TOTAL	5,816,320	2,883,781	730,738	426,323	1,666,664	92,188	1,316	12,366	2,944
507-Rents	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
508-IPP Operations	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
509-Allowances	51,539	PROD_ENERGY	TOTAL	51,539	18,936	6,060	3,976	21,247	868	16	352	83
510-Supervision & Engineering	1,591,139	LABOR_PROD	TOTAL	1,591,139	713,534	195,179	118,881	529,734	25,804	410	6,148	1,449
511-Structures	2,099,968	PROD_DEMAND	TOTAL	2,099,968	1,041,182	263,831	153,923	601,745	33,284	475	4,465	1,063
512-Boiler Plant	13,610,539	PROD_ENERGY	TOTAL	13,610,539	5,000,766	1,600,411	1,049,893	5,611,082	229,276	4,244	93,052	21,815
513-Electric Plant	4,615,859	PROD_DEMAND	TOTAL	4,615,859	2,288,582	579,917	338,332	1,322,672	73,161	1,044	9,814	2,336
514-Misc Steam Plant	1,655,148	PROD_DEMAND	TOTAL	1,655,148	820,637	207,946	121,319	474,282	26,234	374	3,519	838
555-Purchased Power Expense Demand	48,915,360	PROD_DEMAND	TOTAL	48,915,360	24,252,655	6,145,521	3,585,388	14,016,675	775,300	11,067	103,998	24,756
555-Purchased Power Expense Energy	231,108,512	PROD_ENERGY	TOTAL	231,108,512	84,913,576	27,175,168	17,827,303	95,276,808	3,893,134	72,067	1,580,034	370,421
556-Sys Control & Load Dispatching	171,390	PROD_DEMAND	TOTAL	171,390	84,977	21,533	12,563	49,112	2,717	39	364	87
557- Other Expenses	834,562	PROD_DEMAND	TOTAL	834,562	413,783	104,851	61,172	239,143	13,228	189	1,774	422
Total Production Expenses	426,462,247		TOTAL	426,462,247	165,518,279	50,699,561	32,632,478	167,169,488	7,115,501	127,100	2,591,715	608,125
Transmission												
560-Supervision & Engineering	3,543,430	EXP_OM_TRAN	TOTAL	3,543,430	1,745,565	442,101	257,846	1,034,096	55,680	795	5,934	1,412
561-Load Dispatching - Company	383,742	TRANS_TOTAL	TOTAL	383,742	189,039	47,878	27,924	111,989	6,030	86	643	153
561-Load Dispatching - PJM	1,588,636	TRAN_LSE	TOTAL	1,588,636	787,659	199,590	116,444	455,223	25,180	359	3,378	804
562-Station Equipment	305,142	TRANS_TOTAL	TOTAL	305,142	150,319	38,071	22,204	89,051	4,795	68	511	122
563-Overhead Lines	23,537	TRANS_TOTAL	TOTAL	23,537	11,595	2,937	1,713	6,869	370	5	39	9
564-Underground Lines	59,112	TRANS_TOTAL	TOTAL	59,112	29,120	7,375	4,301	17,251	929	13	99	24
565 LSE Transmission Purchases	70,066,025	TRAN_LSE	TOTAL	70,066,025	34,739,336	8,802,802	5,135,686	20,077,388	1,110,535	15,852	148,966	35,460
565 LSE Transmission Purchases - Retail Energy	73,833	PROD_ENERGY	TOTAL	73,833	27,128	8,682	5,695	30,438	1,244	23	505	118
565 Transmission by Others	116,195	TRANS_TOTAL	TOTAL	116,195	57,240	14,497	8,455	33,910	1,826	26	195	46
565 Transmission Purchases - Non-Juris	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
566-Misc Transmission	(5,727,977)	TRANS_TOTAL	TOTAL	(5,727,977)	(2,821,717)	(714,659)	(416,809)	(1,671,623)	(90,007)	(1,286)	(9,592)	(2,283)
567-Rents	273	TRANS_TOTAL	TOTAL	273	134	34	20	80	4	0	0	0
Total Transmission Expenses	70,431,948		TOTAL	70,431,948	34,915,418	8,849,308	5,163,478	20,184,672	1,116,585	15,943	150,677	35,866
568-Supervision & Engineering	1,551	EXP_OM_TRAN	TOTAL	1,551	764	194	113	453	24	0	3	1
569-Structures	159,934	TRANS_TOTAL	TOTAL	159,934	78,787	19,954	11,638	46,674	2,513	36	268	64
570-Station Equipment	633,520	TRANS_TOTAL	TOTAL	633,520	312,085	79,042	46,100	184,883	9,955	142	1,061	253
571-Overhead Lines	5,364,065	TRANS_TOTAL	TOTAL	5,364,065	2,642,447	669,255	390,329	1,565,421	84,289	1,204	8,983	2,138
572-Underground Lines	656	TRANS_TOTAL	TOTAL	656	323	82	48	191	10	0	1	0
573-Misc Transmission Expenses	3,113	TRANS_TOTAL	TOTAL	3,113	1,534	388	227	908	49	1	5	1
575- PJM Admin	946,009	TRAN_LSE	TOTAL	946,009	469,039	118,853	69,340	271,078	14,994	214	2,011	479
Total Transmission Maintenance	7,108,848		TOTAL	7,108,848	3,504,978	887,768	517,794	2,069,610	111,835	1,597	12,332	2,935
Total Transmission O&M	77,540,796		TOTAL	77,540,796	38,420,396	9,737,076	5,681,272	22,254,282	1,228,419	17,541	163,009	38,801
Distribution Operation												
580 Supervision & Engineering	841,573	TOTOXEXP	TOTAL	841,573	562,453	179,314	33,626	22,494	6,856	238	26,432	10,159
581 Load Dispatching	2,546	DIST_CPD	TOTAL	2,546	1,684	423	233	152	52	1	1	0
582 Station Expenses	413,046	DIST_CPD	TOTAL	413,046	273,197	68,657	37,730	24,688	8,478	122	140	33
583 Overhead Lines	288,432	DIST_OHLINES	TOTAL	288,432	226,852	53,241	4,739	2,175	1,181	25	114	105
584 Underground Lines	236,456	DIST_UGLINES	TOTAL	236,456	180,524	42,897	7,099	4,089	1,666	30	79	71
585 Street Lighting	60,794	DIST_SL	TOTAL	60,794	-	-	-	-	-	-	-	60,794
586 Meters	1,178,553	DIST_METERS	TOTAL	1,178,553	532,434	475,691	82,382	75,926	11,007	1,112	-	-
587 Customer Installs	206,361	DIST_PCUST	TOTAL	206,361	124,760	29,285	423	44	132	8	51,659	51
588 Miscellaneous Distribution	3,633,651	RB_GUP_EPIS_D	TOTAL	3,633,651	2,631,506	645,601	115,561	62,699	27,156	532	132,378	18,219
589 Rents	936,380	RB_GUP_EPIS_D	TOTAL	936,380	678,131	166,369	29,780	16,157	6,998	137	34,113	4,695
Total Distribution Operations Expenses	7,797,792		TOTAL	7,797,792	5,211,541	1,661,478	311,574	208,426	63,526	2,204	244,916	94,127
Distribution Maintenance												
590 Supervision & Engineering	7,820	TOTMXEXP	TOTAL	7,820	6,132	1,442	135	63	33	1	8	5
591 Structures	19,036	DIST_CPD	TOTAL	19,036	12,591	3,164	1,739	1,138	391	6	6	2
592 Station Equipment	306,973	DIST_CPD	TOTAL	306,973	203,038	51,025	28,041	18,348	6,301	91	104	25
593 Overhead Lines	33,366,980	TOTOHLINES	TOTAL	33,366,980	26,243,198	6,159,109	548,245	251,648	136,608	2,932	13,130	12,111
5930010 Storm Expense Amortization	1,649,914	TOTOHLINES	TOTAL	1,649,914	1,297,661	304,553	27,109	12,443	6,755	145	649	599
593-Forestry Direct Assigned	348,770	TOTOHLINES	TOTAL	348,770	274,308	64,378	5,731	2,630	1,428	31	137	127
594 Underground Lines	51,193	TOTUGLINES	TOTAL	51,193	39,084	9,287	1,537	885	361	6	17	15
595 Line Transformers	30,956	DIST_TRANSF	TOTAL	30,956	23,427	5,288	1,342	447	349	5	77	22
596 Street Lighting	11,264	DIST_SL	TOTAL	11,264	-	-	-	-	-	-	-	11,264
597 Meters	30,845	DIST_METERS	TOTAL	30,845	13,935	12,450	2,156	1,987	288	29	-	-
598 Miscellaneous Distribution	23,102	DIST_OL	TOTAL	23,102	-	-	-	-	-	-	23,102	-

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Total Distribution Maintenance Expenses	35,846,853		TOTAL	35,846,853	28,113,373	6,610,696	616,035	289,590	152,513	3,245	37,232	24,169
Total Distribution O&M	43,644,645		TOTAL	43,644,645	33,324,915	8,272,174	927,608	498,016	216,039	5,449	282,148	118,296
Customer Accounts												
901 Supervision	17,501	TOTOX234	TOTAL	17,501	13,305	2,706	42	7	12	1	1,424	4
902 Meter Read	451,192	CUST_902	TOTAL	451,192	330,859	116,553	2,614	535	611	20	-	-
903 Customer Records	5,198,531	CUST_903	TOTAL	5,198,531	4,388,371	791,583	11,619	1,816	3,558	203	-	1,382
904 Uncollectibles	2,721,853	CUST_TOTAL	TOTAL	2,721,853	1,645,294	386,237	5,669	887	1,736	100	681,256	674
905 Miscellaneous	23,110	TOTOX234	TOTAL	23,110	17,569	3,573	55	9	16	1	1,881	6
Total	8,412,187		TOTAL	8,412,187	6,395,399	1,300,651	19,999	3,253	5,933	325	684,561	2,066
907 - 910 Total Customer Services Expenses	1,446,710	CUST_TOTAL	TOTAL	1,446,710	874,501	205,291	3,013	471	923	53	362,099	358
911 - 916 Total Sales Expenses	47,429	CUST_TOTAL	TOTAL	47,429	28,670	6,730	99	15	30	2	11,871	12
Administrative & General Expense												
920-Salaries	10,372,392	LABOR_M	TOTAL	10,372,392	6,046,146	1,526,862	523,436	2,010,324	114,824	1,977	134,686	14,136
921-Office Supplies	724,820	LABOR_M	TOTAL	724,820	422,503	106,697	36,578	140,481	8,024	138	9,412	988
922-Administrative Expense Transferred	(909,197)	LABOR_M	TOTAL	(909,197)	(529,978)	(133,838)	(45,882)	(176,216)	(10,065)	(173)	(11,806)	(1,239)
923-Outside Services	3,546,467	LABOR_M	TOTAL	3,546,467	2,067,263	522,056	178,970	687,358	39,260	676	46,051	4,833
924-Property Insurance	1,048,191	RB_GUP_EPIS	TOTAL	1,048,191	612,122	152,807	59,320	192,397	13,061	204	15,988	2,292
925-Injuries & Damages	(1,898,572)	LABOR_M	TOTAL	(1,898,572)	(1,106,692)	(279,478)	(95,810)	(367,972)	(21,018)	(362)	(24,653)	(2,587)
926-Employee Pension & Benefits	(2,198,006)	LABOR_M	TOTAL	(2,198,006)	(1,281,234)	(323,556)	(110,921)	(426,006)	(24,332)	(419)	(28,541)	(2,996)
9260057 Post Ret Medicare Subsidy Direct	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
927-Franchise Requirements	137,624	LABOR_M	TOTAL	137,624	80,222	20,259	6,945	26,674	1,524	26	1,787	188
928-Regulatory Commission Expense Allocated	956,396	LABOR_M	TOTAL	956,396	557,491	140,786	48,264	185,364	10,587	182	12,419	1,303
928- Rate Case Expense	1,711,551	RSALE	TOTAL	1,711,551	762,059	275,027	146,160	459,440	35,093	630	27,949	5,192
930-General Advertising Expense	1,395,123	LABOR_M	TOTAL	1,395,123	813,228	205,368	70,404	270,396	15,444	266	18,116	1,901
931-Rent	188,726	LABOR_M	TOTAL	188,726	110,010	27,781	9,524	36,578	2,089	36	2,451	257
Total A&G Operation	15,075,515		TOTAL	15,075,515	8,553,139	2,240,771	826,988	3,038,817	184,492	3,181	203,858	24,268
Total A&G Maintenance	2,594,046	LABOR_M	TOTAL	2,594,046	1,512,089	381,855	130,907	502,765	28,717	494	33,684	3,535
Total A&G Expenses	17,669,561		TOTAL	17,669,561	10,065,228	2,622,626	957,895	3,541,582	213,209	3,675	237,542	27,803
Total O&M Expenses	575,223,575		TOTAL	575,223,575	254,627,387	72,844,110	40,222,363	193,467,108	8,780,054	154,145	4,332,945	795,462
O&M Adjustments												
Adj 3 - Env Surcharge - Remove Mitchell FGD Expenses	(2,957,290)	PROD_ENERGY	TOTAL	(2,957,290)	(1,086,563)	(347,736)	(228,120)	(1,219,173)	(49,817)	(922)	(20,218)	(4,740)
Adj 6 - Fuel Under (Over) Revenue & Expense	(141,738,721)	PROD_ENERGY	TOTAL	(141,738,721)	(52,077,449)	(16,666,515)	(10,933,475)	(58,433,213)	(2,387,657)	(44,199)	(969,034)	(227,179)
Adj 8 - Remove PPA Rider Revenue, Expense	106,238	PROD_ENERGY	TOTAL	106,238	39,034	12,492	8,195	43,798	1,790	33	726	170
Adj 2 - Remove BSDR Rider Exp	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 10 - Remove HEAP & DSM Surcharge	(765,610)	CUST_TOTAL	TOTAL	(765,610)	(462,793)	(108,642)	(1,595)	(249)	(488)	(28)	(191,626)	(190)
Adj 11 - Remove Economic Development Surcharge	(372,763)	CUST_TOTAL	TOTAL	(372,763)	(225,326)	(52,896)	(776)	(121)	(238)	(14)	(93,299)	(92)
Adj 12 - Specific Customer Adjustment	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Adj 13 - Customer Annualization Adjustment	885,912	REVYEC_EXP_OM	TOTAL	885,912	(267,237)	97,029	391,459	698,292	44,243	(5,990)	(72,389)	506
Adj 14 - Weather Normalization Adjustment	5,803,037	WEATHER_FXNL_OM	TOTAL	5,803,037	5,008,812	505,012	231,175	-	58,038	-	-	-
Adj 16 - Normalization of Major Storms	(6,313,675)	TDOMX	TOTAL	(6,313,675)	(4,770,491)	(1,184,631)	(143,757)	(124,129)	(33,252)	(807)	(39,926)	(16,683)
Adj 17 - Amortization of Big Sandy Operation Rider	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 18 - Rate Case Expense	279,410	RSALE	TOTAL	279,410	124,406	44,898	23,861	75,003	5,729	103	4,563	848
Adj 19 - Eliminate Advertising Expense A&G	(169,849)	LABOR_M	TOTAL	(169,849)	(99,006)	(25,003)	(8,571)	(32,919)	(1,880)	(32)	(2,206)	(231)
Adj 20 - Annualization of Lease Costs	(406,497)	RB_GUP	TOTAL	(406,497)	(237,386)	(59,260)	(23,005)	(74,613)	(5,065)	(79)	(6,200)	(889)
Adj 21 - Pension & OPEB Expense Adjustment	(811,799)	LABOR_M	TOTAL	(811,799)	(473,204)	(119,500)	(40,967)	(157,339)	(8,987)	(155)	(10,541)	(1,106)
Adj 22 - Employee Related Group Benefit Expenses	77,962	LABOR_M	TOTAL	77,962	45,445	11,476	3,934	15,110	863	15	1,012	106
Adj 23 - PJM LSE OATT Expense	7,893,781	TRAN_LSE	TOTAL	7,893,781	3,913,804	991,742	578,597	2,261,959	125,115	1,786	16,783	3,995
Adj 24 - Normalize bad debt expense	(84,408)	CUST_TOTAL	TOTAL	(84,408)	(51,023)	(11,978)	(176)	(27)	(54)	(3)	(21,127)	(21)
Adj 26 - Severance Related Payroll Expenses - Big Sandy Plant	-	LABOR_PROD	TOTAL	-	-	-	-	-	-	-	-	-
Adjs 27-33 - Total Incentive Compensation & Payroll Adjs	1,430,708	LABOR_M	TOTAL	1,430,708	833,971	210,607	72,200	277,293	15,838	273	18,578	1,950
Adj 34 - Remove Non-Recoverable Business Expenses	(8,467)	RB_GUP	TOTAL	(8,467)	(4,945)	(1,234)	(479)	(1,554)	(106)	(2)	(129)	(19)
Adj 35 - Plant Maintenance Normalization	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 47 - Veg Management Tree Trimming	-	TOTOHLINES	TOTAL	-	-	-	-	-	-	-	-	-
Adj 48 - KPSC	(29,109)	CUST_TOTAL	TOTAL	(29,109)	(17,596)	(4,131)	(61)	(9)	(19)	(1)	(7,286)	(7)
Adj 49 - Rockport UPA Demand Expense	(46,035,951)	PROD_DEMAND	TOTAL	(46,035,951)	(22,825,019)	(5,783,764)	(3,374,334)	(13,191,581)	(729,662)	(10,415)	(97,876)	(23,299)
Adj 50 - Replacement capacity	413,681	PROD_DEMAND	TOTAL	413,681	205,107	51,973	30,322	118,540	6,557	94	880	209
Adj 51 - Def and Amortize GreenHat Default Charges	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Adj 52 - Removal of Pole Rental Rev & Exp to prior periods	9,065	RB_GUP_EPIS_D	TOTAL	9,065	6,565	1,611	288	156	68	1	330	45

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Adj 53 - Removal Non-Ongoing Exp - COVID-19 Pandemic	(83,222)	LABOR_M	TOTAL	(83,222)	(48,511)	(12,251)	(4,200)	(16,130)	(921)	(16)	(1,081)	(113)
Adj 54 - Removal Prior Period Insurance Proceeds	50,544	CUST_903	TOTAL	50,544	42,667	7,696	113	18	35	2	-	13
Adj 55 - Removal Rockport - Energy	10,322,581	PROD_ENERGY	TOTAL	10,322,581	3,792,709	1,213,793	796,266	4,255,588	173,889	3,219	70,573	16,545
Adj 56 - Amoritization Deferred Plant Maintenance Costs	(931,318)	PROD_ENERGY	TOTAL	(931,318)	(342,184)	(109,510)	(71,840)	(383,945)	(15,688)	(290)	(6,367)	(1,493)
Adj 65 - Non-FAC	(11,728,132)	PROD_ENERGY	TOTAL	(11,728,132)	(4,309,134)	(1,379,066)	(904,687)	(4,835,040)	(197,566)	(3,657)	(80,182)	(18,798)
Adj 66 - Removal of Regulatory Asset Amortization	(2,542,980)	RSALE	TOTAL	(2,542,980)	(1,132,249)	(408,629)	(217,161)	(682,624)	(52,141)	(937)	(41,525)	(7,714)
Total Operations and Maintenance Expense Adjustments	(187,706,872)		TOTAL	(187,706,872)	(74,417,596)	(23,126,417)	(13,816,795)	(71,406,911)	(3,051,376)	(62,022)	(1,547,568)	(278,186)
Adjusted Operating & Maintenance Expenses	387,516,703		TOTAL	387,516,703	180,209,791	49,717,693	26,405,568	122,060,197	5,728,678	92,123	2,785,377	517,276
Depreciation, Amortization & Reg. Debits Expense												
Production & Reg Debits	53,226,249	RB_GUP-Land_P	TOTAL	53,226,249	26,390,030	6,687,123	3,901,367	15,251,958	843,627	12,042	113,163	26,938
Transmission & Reg. Debits	21,241,647	RB_GUP-Land_T	TOTAL	21,241,647	10,461,850	2,649,640	1,545,329	6,202,722	333,689	4,766	35,258	8,392
Distribution	36,794,164	RB_GUP-Land_D	TOTAL	36,794,164	26,666,548	6,540,975	1,151,150	621,313	270,810	5,336	1,351,975	186,059
General & Intangible	14,030,353	RB_GUP-Land_G	TOTAL	14,030,353	8,178,400	2,065,330	708,033	2,719,291	155,319	2,674	182,185	19,121
Total Depreciation & Amort Expense	125,292,413		TOTAL	125,292,413	71,696,827	17,943,069	7,305,879	24,795,285	1,603,445	24,818	1,682,581	240,510
Depreciation & Amortization Adjustments												
Adj 2 - Decommissioning Rider Removal	(13,032,207)	RB_GUP-Land_P	TOTAL	(13,032,207)	(6,461,480)	(1,637,312)	(955,232)	(3,734,373)	(206,558)	(2,948)	(27,708)	(6,596)
Adj 3 - Env Surcharge - Remove Mitchell FGD Expenses	(9,079,176)	RB_GUP-Land_P	TOTAL	(9,079,176)	(4,501,533)	(1,140,670)	(665,484)	(2,601,634)	(143,903)	(2,054)	(19,303)	(4,595)
Adj 5 - Environmental Surcharge Revenue Sync	(3,573,270)	RB_GUP-Land_P	TOTAL	(3,573,270)	(1,771,658)	(448,931)	(261,913)	(1,023,919)	(56,636)	(808)	(7,597)	(1,808)
Adj 25 - Amort Big Sandy Operation Rider & NERC Cyber Secur	666,115	RB_GUP-Land_P	TOTAL	666,115	330,266	83,688	48,825	190,875	10,558	151	1,416	337
Adj 36 - Annualization Depreciation/Amortization Exp Production	553,061	RB_GUP-Land_P	TOTAL	553,061	274,212	69,484	40,538	158,479	8,766	125	1,176	280
Adj 36 - Annualization Depreciation/Amortization Exp Transmissi	526,787	RB_GUP-Land_T	TOTAL	526,787	259,451	65,710	38,324	153,826	8,275	118	874	208
Adj 36 - Annualization Depreciation/Amortization Exp Distributior	966,467	RB_GUP-Land_D	TOTAL	966,467	700,446	171,811	30,237	16,320	7,113	140	35,512	4,887
Adj 36 - Annualization Depreciation/Amortization Exp General	63,037	RB_GUP-Land_G	TOTAL	63,037	36,745	9,279	3,181	12,218	698	12	819	86
Adj 38 - ARO Depreciation Expense	471,246	RB_GUP-Land_P	TOTAL	471,246	233,648	59,205	34,541	135,035	7,469	107	1,002	238
Total Depreciation & Amort Adjustments	(22,437,940)		TOTAL	(22,437,940)	(10,899,903)	(2,767,734)	(1,686,982)	(6,693,173)	(364,218)	(5,158)	(13,809)	(6,962)
Adjusted Depreciation & Amortization Expense	102,854,473		TOTAL	102,854,473	60,796,924	15,175,334	5,618,897	18,102,112	1,239,227	19,659	1,668,772	233,547
Taxes Other Than Income												
Federal Insurance Contribution Excise	1,773,461	LABOR_M	TOTAL	1,773,461	1,033,764	261,061	89,497	343,723	19,633	338	23,029	2,417
Federal Unemployment Tax	13,073	LABOR_M	TOTAL	13,073	7,620	1,924	660	2,534	145	2	170	18
Kentucky Unemployment	22,500	LABOR_M	TOTAL	22,500	13,115	3,312	1,135	4,361	249	4	292	31
Kentucky Real & Personal Property	18,764,063	RB_GUP	TOTAL	18,764,063	10,957,829	2,735,460	1,061,907	3,444,175	233,807	3,646	286,212	41,028
Kentucky PSC Maintenance	-	RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Kentucky Sales & Use	(118,587)	TDPLANT	TOTAL	(118,587)	(74,216)	(18,405)	(5,836)	(15,875)	(1,302)	(21)	(2,570)	(362)
Regis Fee	26	LABOR_M	TOTAL	26	15	4	1	5	0	0	0	0
Kentucky Business Occup Taxes	6,245,514	LABOR_M	TOTAL	6,245,514	3,640,558	919,367	315,176	1,210,474	69,139	1,190	81,098	8,512
Gross Receipts	16,484	RSALE	TOTAL	16,484	7,339	2,649	1,408	4,425	338	6	269	50
Business Franchise Taxes	-	RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Federal Excise	5,698	LABOR_M	TOTAL	5,698	3,321	839	288	1,104	63	1	74	8
Taxes on Capital Leases	556,734	RB_GUP	TOTAL	556,734	325,121	81,162	31,507	102,189	6,937	108	8,492	1,217
Total Taxes Other Than Income	27,278,966		TOTAL	27,278,966	15,914,467	3,987,373	1,495,742	5,097,115	329,009	5,275	397,067	52,918
Taxes Other Than Income Adjustments												
Adj 3 - Env Surcharge - Remove Mitchell FGD Expenses	(186,284)	RB_GUP	TOTAL	(186,284)	(108,786)	(27,157)	(10,542)	(34,193)	(2,321)	(36)	(2,841)	(407)
Adjs 27-33 - Total Incentive Compensation & Payroll Adjs	128,757	LABOR_M	TOTAL	128,757	75,053	18,954	6,498	24,955	1,425	25	1,672	175
Adj 40 - KPSC Maintenance Assessment	-	RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Adj 57 - Property Tax Expense Annualization	2,587,239	RB_GUP	TOTAL	2,587,239	1,510,895	377,172	146,419	474,892	32,238	503	39,464	5,657
Adj 58 - Sales and Use Tax	(65,715)	TDPLANT	TOTAL	(65,715)	(41,127)	(10,199)	(3,234)	(8,797)	(721)	(12)	(1,424)	(201)
Adj 59 - State Business and Occupation Taxes	4,231	LABOR_M	TOTAL	4,231	2,466	623	214	820	47	1	55	6
Total Adjustments to Taxes Other Than Income	2,468,228		TOTAL	2,468,228	1,438,501	359,393	139,354	457,677	30,668	480	36,925	5,230
Adjusted Taxes Other Than Income	29,747,194		TOTAL	29,747,194	17,352,968	4,346,766	1,635,096	5,554,792	359,677	5,755	433,992	58,148
Other Expenses												
Gain/Loss on Disposition of Utility Plant	(11,516)	RB_GUP_EPIS_D	TOTAL	(11,516)	(8,340)	(2,046)	(366)	(199)	(86)	(2)	(420)	(58)
A/R Factoring	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Gain/Loss on Disposition of Allowances	(138,221)	PROD_ENERGY	TOTAL	(138,221)	(50,785)	(16,253)	(10,662)	(56,983)	(2,328)	(43)	(945)	(222)
Accretion	549,697	PROD_DEMAND	TOTAL	549,697	272,544	69,062	40,292	157,515	8,713	124	1,169	278
Interest Income - Corp. Borrowing Program	(100,083)	RB_GUP	TOTAL	(100,083)	(58,446)	(14,590)	(5,664)	(18,370)	(1,247)	(19)	(1,527)	(219)
Interest Expense - Corp. Borrowing Program	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Other Interest Expense	452,448	RB_GUP	TOTAL	452,448	264,220	65,959	25,605	83,048	5,638	88	6,901	989
Interest on Customer Deposits	452,405	CUST_DEP_FXNL	TOTAL	452,405	295,401	69,273	26,605	59,269	364	-	1,493	-
Total Other Expenses	1,204,730		TOTAL	1,204,730	714,595	171,404	75,809	224,280	11,053	148	6,672	769

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Other Expense Adjustments												
Adj 15 - Interest on Customer Deposits	1,258,220	CUST_DEP_FXNL	TOTAL	1,258,220	821,564	192,660	73,992	164,839	1,013	-	4,152	-
Adj 39 - ARO Depreciation	255,569	PROD_DEMAND	TOTAL	255,569	126,713	32,109	18,733	73,233	4,051	58	543	129
Total Adjustments to Other Expenses	1,513,789		TOTAL	1,513,789	948,277	224,768	92,725	238,072	5,064	58	4,695	129
Total Adjusted Other Expenses	2,718,519		TOTAL	2,718,519	1,662,872	396,172	168,534	462,352	16,117	206	11,367	899
Total Operating Expense Before Income Tax	522,836,889		TOTAL	522,836,889	260,022,556	69,635,966	33,828,095	146,179,453	7,343,699	117,743	4,899,508	809,870
Gross Operating Income	52,461,489		TOTAL	52,461,489	(579,874)	19,781,487	14,489,480	10,717,627	3,966,493	67,670	3,271,253	747,353
Allowance for Borrowed Funds Used During Construction	7,538,567	RATEBASE	TOTAL	7,538,567	4,407,620	1,104,397	421,043	1,369,712	94,688	1,495	122,055	17,556
Interest Synchronization Tax	(50,554,349)	RATEBASE	TOTAL	(50,554,349)	(29,557,921)	(7,406,191)	(2,823,555)	(9,185,419)	(634,990)	(10,023)	(818,516)	(117,735)
Taxable Income Before Schedule M Adjustments	9,445,707		TOTAL	9,445,707	(25,730,174)	13,479,693	12,086,968	2,901,920	3,426,192	59,142	2,574,793	647,174
Schedule M Income Adjustments												
Book vs. Tax Depreciation - Normalized	33,507,292	RB_GUP	TOTAL	33,507,292	19,567,573	4,884,754	1,896,264	6,150,320	417,513	6,511	511,093	73,264
AFUDC - HR/J	-	BULK_TRANS	TOTAL	-	-	-	-	-	-	-	-	-
ABFUDC	-	RB_GUP_CWIP	TOTAL	-	-	-	-	-	-	-	-	-
ABFUDC - HR/J	38,616	BULK_TRANS	TOTAL	38,616	19,146	4,852	2,830	11,065	612	9	82	20
Interest Capitalization	3,503,474	RB_GUP	TOTAL	3,503,474	2,045,957	510,743	198,271	643,069	43,655	681	53,439	7,660
Capitalized Relocation Costs	(263,258)	RB_GUP	TOTAL	(263,258)	(153,737)	(38,378)	(14,898)	(48,321)	(3,280)	(51)	(4,016)	(576)
Book/Tax Unit of Property	(32,860,420)	RB_GUP	TOTAL	(32,860,420)	(19,189,813)	(4,790,452)	(1,859,656)	(6,031,586)	(409,452)	(6,385)	(501,226)	(71,849)
Percent Repair Allowance	7,674,627	RB_GUP	TOTAL	7,674,627	4,481,825	1,118,821	434,327	1,408,691	95,629	1,491	117,063	16,781
Removal Costs	(12,341,762)	RB_GUP	TOTAL	(12,341,762)	(7,207,337)	(1,799,205)	(698,452)	(2,265,351)	(153,783)	(2,398)	(188,251)	(26,985)
Tax Amortization of Pollution Control	7,711,168	PROD_DEMAND	TOTAL	7,711,168	3,823,263	968,799	565,212	2,209,632	122,221	1,745	16,395	3,903
Property Tax - State 2- Old Method	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Provision for Possible Revenue Refunds	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Deferred Fuel	-	FUELREV	TOTAL	-	-	-	-	-	-	-	-	-
Insurance premiums accrued	(7,262)	LABOR_M	TOTAL	(7,262)	(4,233)	(1,069)	(366)	(1,407)	(80)	(1)	(94)	(10)
Accrued Book Pension Expense	27,292,877	LABOR_M	TOTAL	27,292,877	15,909,226	4,017,632	1,377,318	5,289,766	302,137	5,201	354,400	37,196
Accrued Book Pension Costs - SFAS 158	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Supplemental Executive Retirement	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrd Supplemental Exec Retirement SFAS 158	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrd Supplemental Savings Plan Exp	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Stock Based Compensation	(360,112)	LABOR_M	TOTAL	(360,112)	(209,912)	(53,010)	(18,173)	(69,795)	(3,987)	(69)	(4,676)	(491)
Book Provision for Uncollectible Accounts	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Accrued Companywide Incentive Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrued Book Vacation Pay	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
(ICDP) Incentive Comp Deferral Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrued Book Severance Benefits	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset on Deferred RTO Costs	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Customer Adv Inc for Tax	(61,751)	TDPLANT	TOTAL	(61,751)	(38,646)	(9,584)	(3,039)	(8,267)	(678)	(11)	(1,338)	(189)
Deferred Book Contract Revenue	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Deferred Storm Damage	-	EXP_OM_DIST	TOTAL	-	-	-	-	-	-	-	-	-
OSS Margin Sharing	1,060,800	RB_GUP	TOTAL	1,060,800	619,486	154,645	60,033	194,712	13,218	206	16,181	2,319
Advance Rental Income	6,370	REV_RENT	TOTAL	6,370	4,627	1,105	183	353	43	1	50	8
Deferred Rev - Bonus Lease		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset - SFAS 158 Pensions		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset - SFAS 158 SERP		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset - SFAS 158 OPEB		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
NET CCS FEED STUDY COSTS		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REMOVAL CST - BIG SANDY		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
SPENT ARO - BIG SANDY		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
NBV - ARO - RETIRED PLANTS		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
BIG SANDY U1 OR-UNDER RECOV		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
BIG SANDY RETIRE COSTS RECOV		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
BIG SANDY RETIRE RIDER U2 O&M		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
UND RECOV-PURCH PWR PPA		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
DEFD DEPREC-ENVIRONMENTAL		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
NERC COMPL/CYBER SEC-DEF DEPR		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
CAPACITY CHARGE TARIFF REV		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET - ROCKPORT CAPACITY		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET-KENTUCKY UNDER RECOV-PPA RIDER		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
REG ASSET-GreenHat Settlement & Liability		TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Book Amortization Loss on Reacquired Debt		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Accrued SFAS 106 Post Retirement Exp	1,964,204	LABOR_M	TOTAL	1,964,204	1,144,949	289,140	99,122	380,692	21,744	374	25,505	2,677
Accrued OPEB Costs SFAS 158		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrd SFAS 112 Post Employment Benefits		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrued Book ARO Expense - SFAS 143		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset Medicare Subsidy Flow Thru		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Book Operating Lease - Total	9,502,808	RB_GUP	TOTAL	9,502,808	5,549,445	1,385,337	537,788	1,744,256	118,408	1,847	144,948	20,778
Gross Receipts - Tax Expense		RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Accured Sales & Use Tax Reserve		TDPLANT	TOTAL	-	-	-	-	-	-	-	-	-
SFAS 109 - Deferred SIT Liability	(465,836)	RB_GUP	TOTAL	(465,836)	(272,039)	(67,910)	(26,363)	(85,505)	(5,804)	(91)	(7,105)	(1,019)
Reg Asset - SFAS 109 - Deferred SIT Liability	465,836	RB_GUP	TOTAL	465,836	272,039	67,910	26,363	85,505	5,804	91	7,105	1,019
Regulatory Asset Accrued SFAS 112		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Restricted Stock Plan	(23,313)	RB_GUP	TOTAL	(23,313)	(13,614)	(3,399)	(1,319)	(4,279)	(290)	(5)	(356)	(51)
Stock Based Compensation	529,624	RB_GUP	TOTAL	529,624	309,290	77,210	29,973	97,213	6,599	103	8,078	1,158
Nontaxable Defd Compensation CSV Earn		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Nondeductible Meals and Travel & Entertainment	(1,573)	LABOR_M	TOTAL	(1,573)	(917)	(232)	(79)	(305)	(17)	(0)	(20)	(2)
RESTRICTED STOCK PLAN - TAX DEDUCTION	(22,866)	RB_GUP	TOTAL	(22,866)	(13,353)	(3,333)	(1,294)	(4,197)	(285)	(4)	(349)	(50)
Capitalized Software Costs Tax	632	RB_GUP	TOTAL	632	369	92	36	116	8	0	10	1
Capitalized Software Costs Book	4,215,119	RB_GUP	TOTAL	4,215,119	2,461,543	614,488	238,544	773,692	52,522	819	64,294	9,216
REG ASSET - UNRECOVERED PLANT - BIG SANDY		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
MTM Book Gain Above the Line Tax Deferral	1,057,682	PROD_ENERGY	TOTAL	1,057,682	388,612	124,369	81,588	436,040	17,817	330	7,231	1,695
Mark & Spread Deferral - 283 A/L		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Provision for Trading Credit Risk (Above Line)		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Provision for FAS 157 A/L		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Reg Liability - Unrealized MTM Gain Deferral		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Book > Tax Basis - EMA A/C 283	73,698	PROD_ENERGY	TOTAL	73,698	27,078	8,666	5,685	30,383	1,241	23	504	118
Total Schedule M Adjustments - Per Books	52,196,674		TOTAL	52,196,674	29,520,827	7,461,991	2,929,898	10,936,492	641,514	10,415	618,946	76,592
Adjustments to Per Books Schedule M												
Adj 2 - Decommissioning Rider Removal	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 5 - Environmental Surcharge Revenue Sync	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Adj 21 - Pension & OPEB Expense Adjustment	(811,799)	LABOR_M	TOTAL	(811,799)	(473,204)	(119,500)	(40,967)	(157,339)	(8,987)	(155)	(10,541)	(1,106)
Adj 25 - NERC Compliance & Cyber Security	-	RB_GUP-Land_P	TOTAL	-	-	-	-	-	-	-	-	-
Adjs 27 - 33 Incentive Compensation & Payroll Adjustments	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Adj 38 - ARO Depreciation Expense	471,246	RB_GUP-Land_P	TOTAL	471,246	233,648	59,205	34,541	135,035	7,469	107	1,002	238
Adj 39 - ARO Accretion	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 51 - Def and Amortize GreenHat Default Charges	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Adj 58 - Sales and Use Tax	(65,715)	TDPLANT	TOTAL	(65,715)	(41,127)	(10,199)	(3,234)	(8,797)	(721)	(12)	(1,424)	(201)
Adj 36 - Depreciation/Amortization Adjustments - Prod	553,061	RB_GUP-Land_P	TOTAL	553,061	274,212	69,484	40,538	158,479	8,766	125	1,176	280
Adj 36 - Depreciation/Amortization Adjustments - Trans	526,787	RB_GUP-Land_T	TOTAL	526,787	259,451	65,710	38,324	153,826	8,275	118	874	208
Adj 36 - Depreciation/Amortization Adjustments - Dist	966,467	RB_GUP-Land_D	TOTAL	966,467	700,446	171,811	30,237	16,320	7,113	140	35,512	4,887
Adj 36 - Depreciation/Amortization Adjustments - Gen & Int	63,037	RB_GUP-Land_G	TOTAL	63,037	36,745	9,279	3,181	12,218	698	12	819	86
		RB_GUP-Land_P	TOTAL	-	-	-	-	-	-	-	-	-
		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Total Adjustments to Per Books Schedule M	1,703,084		TOTAL	1,703,084	990,171	245,791	102,621	309,742	22,614	336	27,418	4,393
Adjusted Schedule M	53,899,758		TOTAL	53,899,758	30,510,998	7,707,781	3,032,519	11,246,233	664,127	10,750	646,364	80,984
Kentucky Taxable Income Before Adjustments	63,345,465		TOTAL	63,345,465	4,780,824	21,187,474	15,119,487	14,148,153	4,090,319	69,892	3,221,157	728,158
Depreciation Adjustments (JWCA and Lookback)	(22,040,159)	RB_GUP	TOTAL	(22,040,159)	(12,871,002)	(3,213,055)	(1,247,309)	(4,045,508)	(274,628)	(4,283)	(336,183)	(48,191)
Kentucky Taxable Income	41,305,306		TOTAL	41,305,306	(8,090,178)	17,974,419	13,872,177	10,102,645	3,815,691	65,609	2,884,974	679,968
Tax Factor (Tax Rate x Apportionment)	5.00000%											
Kentucky Tax	2,065,265		TOTAL	2,065,265	(404,509)	898,721	693,609	505,132	190,785	3,280	144,249	33,998
West Virginia Taxable Income Before Adjustments	63,345,465		TOTAL	63,345,465	4,780,824	21,187,474	15,119,487	14,148,153	4,090,319	69,892	3,221,157	728,158
Tax Depreciation Lookback	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
West Virginia Taxable Income	63,345,465		TOTAL	63,345,465	4,780,824	21,187,474	15,119,487	14,148,153	4,090,319	69,892	3,221,157	728,158
Apportionment Factor	0.1000%											
Apportioned West Virginia Taxable Income	63,345		TOTAL	63,345	4,781	21,187	15,119	14,148	4,090	70	3,221	728
Post Apportionment Schedule M Adjustments	8,584,116	RB_GUP	TOTAL	8,584,116	5,012,948	1,251,408	485,797	1,575,629	106,961	1,668	130,935	18,769
Post Apportionment Taxable Income	8,647,461		TOTAL	8,647,461	5,017,729	1,272,596	500,917	1,589,777	111,051	1,738	134,156	19,497
Tax Rate	6.50%											
West Virginia Tax	562,085		TOTAL	562,085	326,152	82,719	32,560	103,336	7,218	113	8,720	1,267
Illinois Taxable Income Before Depreciation Adjustment	63,345,465		TOTAL	63,345,465	4,780,824	21,187,474	15,119,487	14,148,153	4,090,319	69,892	3,221,157	728,158

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Depreciation Adjustments (JWCA and Lookback)	(20,291,900)	RB_GUP	TOTAL	(20,291,900)	(11,850,055)	(2,958,190)	(1,148,371)	(3,724,612)	(252,844)	(3,943)	(309,516)	(44,368)
Illinois Taxable Income	43,053,565		TOTAL	43,053,565	(7,069,230)	18,229,284	13,971,116	10,423,541	3,837,475	65,949	2,911,641	683,790
Apportionment Factor	0.0000%											
Apportioned Illinois State Taxable Income	-		TOTAL	-	-	-	-	-	-	-	-	-
Post Apportionment Schedule M Adjustments	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Post Apportionment Taxable Income	-		TOTAL	-	-	-	-	-	-	-	-	-
Tax Rate	9.50%											
Illinois Tax	-		TOTAL	-	-	-	-	-	-	-	-	-
Michigan Taxable Income Before Depreciation Adjustment	63,345,465		TOTAL	63,345,465	4,780,824	21,187,474	15,119,487	14,148,153	4,090,319	69,892	3,221,157	728,158
Depreciation Adjustments (JWCA and Lookback)	(21,315,650)	RB_GUP	TOTAL	(21,315,650)	(12,447,904)	(3,107,435)	(1,206,308)	(3,912,524)	(265,601)	(4,142)	(325,132)	(46,607)
Michigan Taxable Income	42,029,815		TOTAL	42,029,815	(7,667,079)	18,080,039	13,913,179	10,235,630	3,824,719	65,750	2,896,025	681,552
Tax Factor (Tax Rate x Apportionment)	0.000000%											
Michigan Tax	-		TOTAL	-	-	-	-	-	-	-	-	-
Total Current State Income Tax	2,627,350		TOTAL	2,627,350	(78,357)	981,440	726,168	608,468	198,003	3,393	152,969	35,266
Deferred State Income Tax												
			TOTAL	(557,968)	(325,842)	(81,342)	(31,577)	(102,416)	(6,952)	(108)	(8,511)	(1,220)
Deferred State Income Tax - WVA Pollution Control	223,187	RB_GUP	TOTAL	223,187	130,337	32,537	12,631	40,966	2,781	43	3,404	488
Adj 55 - Mitchell Plant DSIT Amortization Adjustment	-	RB_GUP_EPIS_P	TOTAL	-	-	-	-	-	-	-	-	-
Total Adjusted Deferred State Income Tax	223,187		TOTAL	223,187	130,337	32,537	12,631	40,966	2,781	43	3,404	488
Total State Income Tax (Current + Deferred)	2,850,537		TOTAL	2,850,537	51,980	1,013,976	738,799	649,434	200,784	3,437	156,373	35,754
Federal Taxable Income	60,718,115		TOTAL	60,718,115	4,859,181	20,206,034	14,393,318	13,539,686	3,892,316	66,499	3,068,188	692,893
Tax Factor (Tax Rate x Apportionment)	21.00%											
Gross Current FIT	12,750,804		TOTAL	12,750,804	1,020,428	4,243,267	3,022,597	2,843,334	817,386	13,965	644,319	145,507
Deferred FIT												
DFIT for Book vs Tax Depreciation Normalized	(6,188,351)	RB_GUP	TOTAL	(6,188,351)	(3,613,870)	(902,149)	(350,215)	(1,135,882)	(77,109)	(1,202)	(94,392)	(13,531)
DFIT ABFUDC	-	RB_GUP_CWIP	TOTAL	-	-	-	-	-	-	-	-	-
Interest Capitalization	(735,730)	RB_GUP	TOTAL	(735,730)	(429,651)	(107,256)	(41,637)	(135,044)	(9,167)	(143)	(11,222)	(1,609)
Property Tax - Book/Tax unit of Property Adj	6,900,688	RB_GUP	TOTAL	6,900,688	4,029,861	1,005,995	390,528	1,266,633	85,985	1,341	105,258	15,088
Removal Costs	2,591,770	RB_GUP	TOTAL	2,591,770	1,513,541	377,833	146,675	475,724	32,294	504	39,533	5,667
Percent Repair Allowance	(1,611,671)	RB_GUP	TOTAL	(1,611,671)	(941,183)	(234,952)	(91,209)	(295,825)	(20,082)	(313)	(24,583)	(3,524)
Tax Amortization of Pollution Control Equip.	(1,619,345)	PROD_DEMAND	TOTAL	(1,619,345)	(802,885)	(203,448)	(118,694)	(464,023)	(25,666)	(366)	(3,443)	(820)
Relocation Costs	55,284	RB_GUP	TOTAL	55,284	32,285	8,059	3,129	10,147	689	11	843	121
Deferred Fuel Costs	-	FUELREV	TOTAL	-	-	-	-	-	-	-	-	-
Insurance Premiums accrued	1,525	LABOR_M	TOTAL	1,525	889	224	77	296	17	0	20	2
Accrued Book Pension Expense	(5,731,504)	LABOR_M	TOTAL	(5,731,504)	(3,340,937)	(843,703)	(289,237)	(1,110,851)	(63,449)	(1,092)	(74,424)	(7,811)
Accrued Book Pension Costs - SFAS 158	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Supplemental Executive Retirement	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrd Suppl Executive Retirement - SFAS 158	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrd Book Supplemental Savings Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Stock Based Compensation	75,623	LABOR_M	TOTAL	75,623	44,081	11,132	3,816	14,657	837	14	982	103
Book Provision - Uncollectible Accounts	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Accrd Companywide Incentive Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrd Book Vacation Pay	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
(IDCP) Incentive Comp Deferral Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrd Book Severance Benefits	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset on Deferred RTO Costs	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Customer Adv Inc for Tax	12,968	TDPLANT	TOTAL	12,968	8,116	2,013	638	1,736	142	2	281	40
Deferred Book Contract Revenue	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Deferred Storm Damage	-	EXP_OM_DIST	TOTAL	-	-	-	-	-	-	-	-	-
Deferred Demand Side Management Exp	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Advance Rental Income	(1,338)	REV_RENT	TOTAL	(1,338)	(972)	(232)	(39)	(74)	(9)	(0)	(10)	(2)
Deferred Revenue - Bonus Lease - Short & Long-Term	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset SFAS 158 Pensions	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset SFAS 158 SERP	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset SFAS 158 OPEB	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset OSS Sharing	(222,768)	RB_GUP	TOTAL	(222,768)	(130,092)	(32,476)	(12,607)	(40,889)	(2,776)	(43)	(3,398)	(487)
REMOVAL CST - BIG SANDY	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
SPENT ARO - BIG SANDY	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
NBV - ARO - RETIRED PLANTS	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset - Unrecovered Plant - Big Sandy	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
BIG SANDY RETIRE COSTS RECOV	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
BIG SANDY RETIRE RIDER U2 O&M	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
UND RECOV-PURCH PWR PPA	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
DEFD DEPREC-ENVIRONMENTAL	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
NERC COMPL/CYBER SEC-DEF DEPR	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
CAPACITY CHARGE TARIFF REV	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET-ROCKPORT CAPACITY DEF-EQ CC	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET-ROCKPORT CAPACITY CC DEFERRAL	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET-ROCKPORT CAPACITY DEFERRAL	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET-KENTUCKY UNDER RECOV-PPA RIDER	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Green Hat Settlement & Liability	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Book Amortization Loss on Reacquired Debt	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Accrued SFAS 106 Post Retirement Expense	(412,483)	LABOR_M	TOTAL	(412,483)	(240,439)	(60,719)	(20,816)	(79,945)	(4,566)	(79)	(5,356)	(562)
Accrued OPEB Costs SFAS 158	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrued SFAS 112 Post Employment Benefits	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Accrued Book ARO Expense SFAS 143	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Medicare Subsidy (PPACA) Reg Asset	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Book Operating Lease	(1,995,590)	RB_GUP	TOTAL	(1,995,590)	(1,165,384)	(290,921)	(112,936)	(366,294)	(24,866)	(388)	(30,439)	(4,363)
Gross Receipts - Tax Expense	-	RSALE	TOTAL	-	-	-	-	-	-	-	-	-
DSIT Entry - WV Pollution Control	(46,870)	RB_GUP	TOTAL	(46,870)	(27,371)	(6,833)	(2,652)	(8,603)	(584)	(9)	(715)	(102)
Accrued Sales & Use Tax Reserve	-	RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset - Accrued SFAS 112	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Excess ADFIT 281 Protected	(549,697)	RB_GUP	TOTAL	(549,697)	(321,012)	(80,136)	(31,109)	(100,898)	(6,849)	(107)	(8,385)	(1,202)
Excess ADFIT 282 Protected and Unprotected	(18,002,602)	RB_GUP	TOTAL	(18,002,602)	(10,513,151)	(2,624,452)	(1,018,814)	(3,304,408)	(224,319)	(3,498)	(274,597)	(39,363)
Excess ADFIT 283 Unprotected	(11,114,134)	RB_GUP	TOTAL	(11,114,134)	(6,490,427)	(1,620,239)	(628,978)	(2,040,018)	(138,486)	(2,160)	(169,526)	(24,301)
Restricted Stock Plan & PSI Stock Based Comp	(68,361)	RB_GUP	TOTAL	(68,361)	(39,921)	(9,966)	(3,869)	(12,548)	(852)	(13)	(1,043)	(149)
Capitalized Software Costs Tax	44,301	RB_GUP	TOTAL	44,301	25,871	6,458	2,507	8,132	552	9	676	97
Capitalized Software Costs Book	(929,609)	RB_GUP	TOTAL	(929,609)	(542,873)	(135,520)	(52,609)	(170,631)	(11,583)	(181)	(14,180)	(2,033)
MTM Book Gain Above the Line Tax Deferral	(222,113)	PROD_ENERGY	TOTAL	(222,113)	(81,608)	(26,117)	(17,133)	(91,568)	(3,742)	(69)	(1,519)	(356)
Mark & Spread Deferral - 283 A/L	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Prov for Trading Credit Risk - Above the Line	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Reg Liability - Unrealized MTM Gain Deferral	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Book > Tax Basis - EMA A/C 283	(15,476)	PROD_ENERGY	TOTAL	(15,476)	(5,686)	(1,820)	(1,194)	(6,380)	(261)	(5)	(106)	(25)
Total Per Books DFIT	(39,785,483)			(39,785,483)	(23,032,821)	(5,769,224)	(2,246,376)	(7,586,558)	(493,849)	(7,788)	(569,745)	(79,122)
DFIT Adjustments												
Adj 2 - Decommissioning Rider Removal	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 5 - Environmental Surcharge Revenue Sync	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Adj 21 - Pension & OPEB Expense Adjustment	170,478	LABOR_M	TOTAL	170,478	99,373	25,095	8,603	33,041	1,887	32	2,214	232
Adj 25 - NERC Compliance & Cyber Security	-	RB_GUP-Land_P	TOTAL	-	-	-	-	-	-	-	-	-
Adjs 27 - 33 Incentive Compensation & Payroll Adjustments	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Adj 38 - ARO Depreciation Expense	(98,962)	RB_GUP-Land_P	TOTAL	(98,962)	(49,066)	(12,433)	(7,254)	(28,358)	(1,569)	(22)	(210)	(50)
Adj XX Cost of Removal	1,667,845	PROD_DEMAND	TOTAL	1,667,845	826,932	209,541	122,249	477,920	26,435	377	3,546	844
Adj 51 - Def and Amortize GreenHat Default Charges	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Adj 58 - Sales and Use Tax	13,800	TDPLANT	TOTAL	13,800	8,637	2,142	679	1,847	151	2	299	42
Adj 36 - Depreciation/Amortization Adjustments - Prod	(91,601)	RB_GUP-Land_P	TOTAL	(91,601)	(45,417)	(11,508)	(6,714)	(26,248)	(1,452)	(21)	(195)	(46)
Adj 36 - Depreciation/Amortization Adjustments - Trans	(87,249)	RB_GUP-Land_T	TOTAL	(87,249)	(42,972)	(10,883)	(6,347)	(25,477)	(1,371)	(20)	(145)	(34)
Adj 36 - Depreciation/Amortization Adjustments - Dist	(160,072)	RB_GUP-Land_D	TOTAL	(160,072)	(116,012)	(28,456)	(5,008)	(2,703)	(1,178)	(23)	(5,882)	(809)
Adj 36 - Depreciation/Amortization Adjustments - Gen & Int	(10,441)	RB_GUP-Land_G	TOTAL	(10,441)	(6,086)	(1,537)	(527)	(2,024)	(116)	(2)	(136)	(14)
Adj 60 - Excess ADFIT 281 Protected	549,697	RB_GUP	TOTAL	549,697	321,012	80,136	31,109	100,898	6,849	107	8,385	1,202
Adj 60 - Excess ADFIT 282 Protected and Unprotected	18,002,602	RB_GUP	TOTAL	18,002,602	10,513,151	2,624,452	1,018,814	3,304,408	224,319	3,498	274,597	39,363
Adj 60 - Excess ADFIT 283 Unprotected	11,114,134	RB_GUP	TOTAL	11,114,134	6,490,427	1,620,239	628,978	2,040,018	138,486	2,160	169,526	24,301
Adj 42 - AFUDC Offset	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Total Adjustments to DFIT	31,070,231		TOTAL	31,070,231	17,999,979	4,496,787	1,784,581	5,873,323	392,443	6,089	451,999	65,030
Total Deferred FIT	(8,715,252)		TOTAL	(8,715,252)	(5,032,842)	(1,272,437)	(461,794)	(1,713,235)	(101,406)	(1,699)	(117,746)	(14,092)
Feedback Prior ITC Normalization Tax	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Total Federal Income Tax	4,035,552		TOTAL	4,035,552	(4,012,414)	2,970,830	2,560,802	1,130,099	715,980	12,266	526,573	131,415
Total Income Tax	6,886,089		TOTAL	6,886,089	(3,960,434)	3,984,806	3,299,601	1,779,533	916,764	15,703	682,947	167,169
Total Expenses	529,722,978		TOTAL	529,722,978	256,062,122	73,620,772	37,127,696	147,958,986	8,260,463	133,446	5,582,455	977,039

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Net Operating Income	45,575,400		TOTAL	45,575,400	3,380,560	15,796,680	11,189,878	8,938,094	3,049,729	51,968	2,588,306	580,183
AFUDC Offset												
Production	534,059	PROD_DEMAND	TOTAL	534,059	264,791	67,097	39,145	153,034	8,465	121	1,135	270
Transmission	2,014,843	RB_GUP_EPIS_T	TOTAL	2,014,843	992,659	251,414	146,632	587,825	31,665	452	3,389	807
Distribution	954,261	RB_GUP_EPIS_D	TOTAL	954,261	691,080	169,546	30,348	16,466	7,132	140	34,765	4,785
General & Intangible	181,783	LABOR_M	TOTAL	181,783	105,963	26,759	9,174	35,232	2,012	35	2,360	248
Total Per Books AFUDC Offset	3,684,946		TOTAL	3,684,946	2,054,492	514,816	225,300	792,558	49,274	747	41,650	6,109
Adj 42 - AFUDC Offest	4,921,688	PROD_DEMAND	TOTAL	4,921,688	2,440,215	618,340	360,749	1,410,308	78,008	1,114	10,464	2,491
Total AFUDC Offset Adjustments	4,921,688		TOTAL	4,921,688	2,440,215	618,340	360,749	1,410,308	78,008	1,114	10,464	2,491
Total Adjusted AFUDC Offsets	8,606,634		TOTAL	8,606,634	4,494,708	1,133,156	586,049	2,202,865	127,282	1,861	52,114	8,600
Adjusted Net Operating Income	54,182,034		TOTAL	54,182,034	7,875,268	16,929,836	11,775,927	11,140,959	3,177,011	53,829	2,640,420	588,784
Current Rate of Return				3.02%	0.75%	6.44%	11.76%	3.42%	14.10%	15.14%	9.09%	14.10%
O&M Labor												
Production Demand	9,581,657	PROD_DEMAND	TOTAL	9,581,657	4,750,668	1,203,799	702,314	2,745,620	151,868	2,168	20,371	4,849
Production Energy	5,601,410	PROD_ENERGY	TOTAL	5,601,410	2,058,062	658,648	432,083	2,309,238	94,358	1,747	38,296	8,978
Transmission	3,508,862	EXP_OM_TRAN	TOTAL	3,508,862	1,728,536	437,788	255,330	1,024,008	55,137	788	5,876	1,399
Distribution	10,176,000	EXP_OM_DIST	TOTAL	10,176,000	7,769,895	1,928,705	216,277	116,115	50,371	1,271	65,784	27,581
Customer Accounts	2,909,767	EXP_OM_CUSTACCT	TOTAL	2,909,767	2,212,162	449,894	6,918	1,125	2,052	112	236,789	715
Customer Service	191,818	EXP_OM_CUSTSERV	TOTAL	191,818	115,949	27,219	400	62	122	7	48,010	48
Total	31,969,514		TOTAL	31,969,514	18,635,273	4,706,054	1,613,322	6,196,168	353,909	6,092	415,127	43,569
Adjusted Fuel & Purchased Power												
Adjusted Purchase Power Demand	9,982,039	PROD_DEMAND	TOTAL	9,982,039	4,949,180	1,254,102	731,662	2,860,349	158,214	2,258	21,223	5,052
Adjusted Purchase Power Energy & Fuel	186,208,329	PROD_ENERGY	TOTAL	186,208,329	68,416,412	21,895,527	14,363,782	76,766,256	3,136,769	58,066	1,273,062	298,455
Calculation of Proposed Revenues												
Proposed Operating Income	124,288,708	RATEBASE	TOTAL	124,288,709	48,864,966	27,200,434	15,691,516	23,878,918	4,057,589	67,729	3,775,503	752,054
					48,864,966	27,200,434	15,691,516	23,878,918	4,057,589	67,729	3,775,503	752,054
Proposed Rate of Return				6.93%	4.66%	10.35%	15.66%	7.33%	18.01%	19.05%	13.00%	18.01%
Income Increase	70,106,674		TOTAL	70,106,675	40,989,698	10,270,598	3,915,589	12,737,959	880,578	13,900	1,135,083	163,270
Gross Revenue Conversion Factor	1.33990											
Revenue Increase	93,935,725		TOTAL	93,935,727	54,921,975	13,761,543	5,246,486	17,067,553	1,179,884	18,625	1,520,894	218,766
Percent Revenue Increase				18.69%	24.14%	17.25%	12.19%	12.87%	11.53%	11.14%	19.44%	14.75%
Proposed Sales Revenue	596,602,363		TOTAL	596,602,365	282,479,538	93,529,669	48,281,642	149,668,670	11,412,403	185,827	9,343,135	1,701,481

Allocation Factor	Total Retail	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
XXXXXXXXXXXXXXXXXXXXXXXXX																		
BULK_TRANS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS BULKTRAN	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
BULK_TRANS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
CUST_902 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 CUSTOMER	1.00000000	0.73329957	0.25758984	0.00070124	0.00003061	0.00470834	0.00098786	0.00009739	-	0.00006679	0.00070124	0.00036732	0.00005009	0.00134405	0.00001113	0.00004452	-	-
CUST_902 TOTAL	1.00000000	0.73329957	0.25758984	0.00070124	0.00003061	0.00470834	0.00098786	0.00009739	-	0.00006679	0.00070124	0.00036732	0.00005009	0.00134405	0.00001113	0.00004452	-	-
CUST_903 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 CUSTOMER	1.00000000	0.84415597	0.15190119	0.00035461	0.00001465	0.00185071	0.00034973	0.00003462	-	0.00001953	0.00020682	0.00010829	0.00001465	0.00067948	0.00000488	0.00003906	-	0.00026584
CUST_903 TOTAL	1.00000000	0.84415597	0.15190119	0.00035461	0.00001465	0.00185071	0.00034973	0.00003462	-	0.00001953	0.00020682	0.00010829	0.00001465	0.00067948	0.00000488	0.00003906	-	0.00026584
CUST_DEP_FXNL PRODUCTION	0.31123443	0.17995919	0.03993292	0.00246410	0.00060749	0.01357864	0.00984622	0.00160335	-	0.00085082	0.02993931	0.02633660	0.00563424	0.00033224	-	-	0.00014931	-
CUST_DEP_FXNL BULKTRAN	0.19948739	0.11534582	0.02559522	0.00157938	0.00038937	0.00870330	0.00631099	0.00102767	-	0.00054534	0.01918976	0.01688059	0.00361130	0.00021295	-	-	0.00009570	-
CUST_DEP_FXNL SUBTRAN	0.06179842	0.03556646	0.00787406	0.00048690	0.00015462	0.00265022	0.00192489	0.00039593	-	0.00016279	0.00589745	0.00661649	-	0.00006503	-	-	0.00000357	-
CUST_DEP_FXNL DISTPRI	0.11040141	0.07226739	0.01591369	0.00098368	-	0.00526463	0.00383028	-	-	0.00032699	0.01167809	-	-	0.00012946	-	-	0.00000719	-
CUST_DEP_FXNL DISTSEC	0.03407666	0.02755383	0.00493508	-	-	0.00143264	-	-	-	0.00007294	-	-	-	0.00003636	-	-	0.00004582	-
CUST_DEP_FXNL ENERGY	0.00865260	0.00399717	0.00112043	0.00006813	0.00001700	0.00043024	0.00030708	0.00004897	-	0.00003141	0.00120041	0.00113931	0.00026748	0.00001058	-	-	0.00001439	-
CUST_DEP_FXNL CUSTOMER	0.27434909	0.21826751	0.04750914	0.00256050	0.00092917	0.00066798	0.00055593	0.00022803	-	0.00000899	0.00043206	0.00014126	0.00004597	0.00001871	-	-	0.00298384	-
CUST_DEP_FXNL TOTAL	1.00000000	0.65295738	0.14288056	0.00814268	0.00209765	0.03272765	0.02277538	0.00330395	-	0.00199929	0.06833709	0.05111424	0.00955899	0.00080533	-	-	0.00329981	-
CUST_SPEC_FXNL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL CUSTOMER	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
CUST_TOTAL TOTAL	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
DIST_CPD PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD DISTPRI	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
DIST_CPD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD TOTAL	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
DIST_METERS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS CUSTOMER	1.00000000	0.45176932	0.35172615	0.04771121	0.00418582	0.03698142	0.02090893	0.01201041	-	0.00026410	0.01662962	0.03980877	0.00772087	0.00911117	0.00022842	0.00094381	-	-
DIST_METERS TOTAL	1.00000000	0.45176932	0.35172615	0.04771121	0.00418582	0.03698142	0.02090893	0.01201041	-	0.00026410	0.01662962	0.03980877	0.00772087	0.00911117	0.00022842	0.00094381	-	-

Allocation Factor	Total Retail	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
DIST_OHLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES DISTPRI	0.12042563	0.07965190	0.01976630	0.00025095	-	0.00862786	0.00237260	-	-	0.00036970	0.00682828	-	-	0.00242517	0.00004658	0.00003560	0.00004096	0.00000973
DIST_OHLINES DISTSEC	0.05395049	0.04102279	0.00828016	-	-	0.00317147	-	-	-	0.00011139	-	-	-	0.00091994	-	0.00001184	0.00035255	0.00008035
DIST_OHLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES CUSTOMER	0.82562388	0.66582734	0.15592569	0.00036384	-	0.00190005	0.00035879	-	-	0.00002021	0.00021224	-	-	0.00069736	0.00000505	0.00004043	-	0.00027288
DIST_OHLINES TOTAL	1.00000000	0.78650203	0.18397215	0.00061479	-	0.01369938	0.00273139	-	-	0.00050130	0.00704052	-	-	0.00404247	0.00005163	0.00008786	0.00039352	0.00036296
DIST_OL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_OL TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_PCUST PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST CUSTOMER	1.00000000	0.60457284	0.14158090	0.00033037	-	0.00172525	0.00032578	-	-	0.00001835	0.00019271	-	-	0.00063320	0.00000459	0.00003671	0.25033151	0.00024778
DIST_PCUST TOTAL	1.00000000	0.60457284	0.14158090	0.00033037	-	0.00172525	0.00032578	-	-	0.00001835	0.00019271	-	-	0.00063320	0.00000459	0.00003671	0.25033151	0.00024778
DIST_POLES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES DISTPRI	0.57249889	0.37866214	0.09396826	0.00119301	-	0.04101652	0.01127925	-	-	0.00175754	0.03246139	-	-	0.01152915	0.00022143	0.00016923	0.00019473	0.00004623
DIST_POLES DISTSEC	0.42750111	0.32506263	0.06561158	-	-	0.02513057	-	-	-	0.00088264	-	-	-	0.00728956	-	0.00009383	0.00279361	0.00063670
DIST_POLES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES TOTAL	1.00000000	0.70372477	0.15957984	0.00119301	-	0.06614709	0.01127925	-	-	0.00264018	0.03246139	-	-	0.01881871	0.00022143	0.00026306	0.00298835	0.00068293
DIST_SERV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV CUSTOMER	1.00000000	0.60508925	0.14170184	-	-	0.00172673	-	-	-	0.00001837	-	-	-	0.00063375	-	0.00003674	0.25054534	0.00024799
DIST_SERV TOTAL	1.00000000	0.60508925	0.14170184	-	-	0.00172673	-	-	-	0.00001837	-	-	-	0.00063375	-	0.00003674	0.25054534	0.00024799
DIST_SL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL CUSTOMER	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_SL TOTAL	1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_TRANSF PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF DISTPRI	0.22862971	0.15122024	0.03752660	0.00047643	-	0.01638011	0.00450441	-	-	0.00070188	0.01296359	-	-	0.00460421	0.00008843	0.00006758	0.00007777	0.00001846
DIST_TRANSF DISTSEC	0.36631915	0.27854118	0.05622155	-	-	0.02153400	-	-	-	0.00075632	-	-	-	0.00624631	-	0.00008040	0.00239380	0.00054558
DIST_TRANSF ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF CUSTOMER	0.40505114	0.32702724	0.07658434	-	-	0.00093323	-	-	-	0.00000993	-	-	-	0.00034251	-	0.00001986	-	0.00013403
DIST_TRANSF TOTAL	1.00000000	0.75678866	0.17033249	0.00047643	-	0.03884734	0.00450441	-	-	0.00146813	0.01296359	-	-	0.01119304	0.00008843	0.00016784	0.00247157	0.00069807
DIST_UGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES DISTPRI	0.28486221	0.18841353	0.04675643	0.00059362	-	0.02040887	0.00561229	-	-	0.00087451	0.01615204	-	-	0.00573664	0.00011018	0.00008420	0.00009690	0.00002301
DIST_UGLINES DISTSEC	0.03650092	0.02775451	0.00560205	-	-	0.00214570	-	-	-	0.00007536	-	-	-	0.00062240	-	0.00000801	0.00023852	0.00005436
DIST_UGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES CUSTOMER	0.67863687	0.54728914	0.12816601	0.00029907	-	0.00156178	0.00029491	-	-	0.00001661	0.00017445	-	-	0.00057321	0.00000415	0.00003323	-	0.00022430
DIST_UGLINES TOTAL	1.00000000	0.76345718	0.18052450	0.00089268	-	0.02411636	0.00590720	-	-	0.00096649	0.01632649	-	-	0.00693224	0.00011433	0.00012544	0.00033542	0.00030167
EXP_OM_CUSTACCT PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT CUSTOMER	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563
EXP_OM_CUSTACCT TOTAL	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563

Allocation Factor	Total Retail 1	RS 2	GS-SEC 3	GS-PRI 4	GS-SUB 5	LGS-SEC 6	LGS-PRI 7	LGS-SUB 8	LGS-TRA 9	IGS-SEC 10	IGS-PRI 11	IGS-SUB 12	IGS-TRA 13	PS-SEC 14	PS-PRI 15	MW 16	OL 17	SL 18
EXP_OM_CUSTSERV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV CUSTOMER	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
EXP_OM_CUSTSERV TOTAL	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
EXP_OM_DIST PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST DISTPRI	0.14914525	0.09864763	0.02448026	0.00031080	-	0.01068547	0.00293843	-	-	0.00045787	0.00845672	-	-	0.00300353	0.00005769	0.00004409	0.00005073	0.00001204
EXP_OM_DIST DISTSEC	0.05466274	0.04156437	0.00838947	-	-	0.00321334	-	-	-	0.00011286	-	-	-	0.00093208	-	0.00001200	0.00035721	0.00008141
EXP_OM_DIST ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST CUSTOMER	0.79619202	0.62333905	0.15427616	0.00193672	0.00014128	0.00298348	0.00102757	0.00040537	-	0.00002737	0.00075167	0.00134361	0.00026059	0.00094441	0.00001224	0.00006878	0.00605673	0.00261698
EXP_OM_DIST TOTAL	1.00000000	0.76355105	0.18714588	0.00224752	0.00014128	0.01688228	0.00396600	0.00040537	-	0.00059810	0.00920839	0.00134361	0.00026059	0.00488002	0.00006993	0.00012486	0.00646467	0.00271044
EXP_OM_TRAN PRODUCTION	0.00000000	0.00000000	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	(0.00000000)	-	(0.00000000)	0.00000000	0.00000000	(0.00000000)	(0.00000000)	(0.00000000)	(0.00000000)	0.00000000	(0.00000000)
EXP_OM_TRAN BULKTRAN	0.75930000	0.37646745	0.09414241	0.00119315	0.00005972	0.04223678	0.01157612	0.00184212	-	0.00182579	0.03322623	0.16189618	0.02062888	0.01181273	0.00022205	0.00017179	0.00161433	0.00038428
EXP_OM_TRAN SUBTRAN	0.24070000	0.11615273	0.02897934	0.00036805	0.00002373	0.01286921	0.00353293	0.00071015	-	0.00054536	0.01021736	0.06349503	-	0.00360964	0.00006924	0.00005266	0.00006026	0.00001431
EXP_OM_TRAN DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN TOTAL	1.00000000	0.49262018	0.12312176	0.00156120	0.00008344	0.05510599	0.01510906	0.00255226	-	0.00237115	0.04344359	0.22539121	0.02062888	0.01542237	0.00029129	0.00022445	0.00167459	0.00039859
EXP_OM_LPP PRODUCTION	0.52381566	0.26209956	0.06451091	0.00078974	0.00003939	0.02916954	0.00813192	0.00130148	-	0.00123374	0.02363923	0.10923805	0.01394220	0.00813931	0.00015226	0.00010820	0.00106031	0.00025982
EXP_OM_LPP BULKTRAN	0.02661271	0.01334593	0.00326574	0.00004005	0.00000200	0.00146798	0.00040832	0.00006612	-	0.00006234	0.00118903	0.00556988	0.00070716	0.00040838	0.00000766	0.00000544	0.00005364	0.00001304
EXP_OM_LPP SUBTRAN	0.00843173	0.00411640	0.00100520	0.00001235	0.00000079	0.00044732	0.00012463	0.00002548	-	0.00001862	0.00036565	0.00218392	-	0.00012481	0.00000239	0.00000167	0.00000200	0.00000049
EXP_OM_LPP DISTPRI	0.03409310	0.02261881	0.00552001	0.00006789	-	0.00242245	0.00067641	-	-	0.00010184	0.00197109	-	-	0.00067877	0.00001299	0.00000917	0.00001099	0.00000267
EXP_OM_LPP DISTSEC	0.01247467	0.00952215	0.00189067	-	-	0.00072823	-	-	-	0.00002509	-	-	-	0.00021060	-	0.00000249	0.00007736	0.00001807
EXP_OM_LPP ENERGY	0.15918534	0.06315848	0.01809348	0.00017534	0.00000863	0.00965963	0.00288809	0.00046317	-	0.00041993	0.01143659	0.04302291	0.00610167	0.00267992	0.00004907	0.00002300	0.00077646	0.00022896
EXP_OM_LPP CUSTOMER	0.23538679	0.18357826	0.04296825	0.00044067	0.00003145	0.00078109	0.00025668	0.00009576	-	0.00000722	0.00018741	0.00030421	0.00005869	0.00025094	0.00000303	0.00001622	0.00581268	0.00059424
EXP_OM_LPP TOTAL	1.00000000	0.55843959	0.13725426	0.00152605	0.00008226	0.04467624	0.01248606	0.00195201	-	0.00186879	0.03878900	0.16031896	0.02080971	0.01249273	0.00022740	0.00016620	0.00779345	0.00111730
FORF_DISC_FXNL PRODUCTION	0.44351305	(0.00771861)	0.16507219	0.00286598	0.00027595	0.04426029	0.04054552	0.00603906	-	0.00531146	0.08214850	0.10072741	0.00380961	-	-	-	0.00017569	-
FORF_DISC_FXNL BULKTRAN	(0.01771738)	0.00158308	(0.00669237)	(0.00004441)	(0.00000015)	0.00227678	0.00254138	(0.00108482)	-	0.00008427	0.00141059	(0.01759300)	(0.00020621)	-	-	-	0.00000747	-
FORF_DISC_FXNL SUBTRAN	(0.00679258)	0.00047400	(0.00200681)	(0.00001358)	(0.00000025)	0.00067050	0.00074913	(0.00040575)	-	0.00002410	0.00041527	(0.00669946)	-	-	-	-	0.00000027	-
FORF_DISC_FXNL DISTPRI	0.05968412	(0.00076449)	0.02721753	0.00050765	-	0.00866219	0.00811594	-	-	0.00096329	0.01497776	-	-	-	-	-	0.00000424	-
FORF_DISC_FXNL DISTSEC	0.01096325	(0.00030954)	0.00863856	-	-	0.00238847	-	-	-	0.00021839	-	-	-	-	-	-	0.00002738	-
FORF_DISC_FXNL ENERGY	0.39549771	(0.00508235)	0.11732011	0.00191707	0.00018805	0.03255457	0.02938175	0.00540233	-	0.00465412	0.08089927	0.12328250	0.00459697	-	-	-	0.00038331	-
FORF_DISC_FXNL CUSTOMER	0.11485184	(0.00410630)	0.11076408	0.00175578	0.00025627	0.00138760	0.00150284	0.00038412	-	0.00003434	0.00073098	0.00024594	0.00001713	-	-	-	0.00187903	-
FORF_DISC_FXNL TOTAL	1.00000000	(0.01592420)	0.42031329	0.00698850	0.00071987	0.09220040	0.08283655	0.01033495	-	0.01128997	0.18058238	0.19996340	0.00821749	-	-	-	0.00247739	-
FUELREV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV ENERGY	1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
FUELREV CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV TOTAL	1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
LABOR_M PRODUCTION	0.29971231	0.14859993	0.03716007	0.00047096	0.00002357	0.01667178	0.00456935	0.00072712	-	0.00072068	0.01311512	0.06390396	0.00814267	0.00466274	0.00008765	0.00006781	0.00063721	0.00015168
LABOR_M BULKTRAN	0.08333811	0.04131975	0.01033274	0.00013096	0.00000655	0.00463576	0.00127055	0.00020218	-	0.00020039	0.00364679	0.01776916	0.00226415	0.00129652	0.00002437	0.00001885	0.00017718	0.00004218
LABOR_M SUBTRAN	0.02641839	0.01274852	0.00318067	0.00004040	0.00000260	0.00141248	0.00038776	0.00007794	-	0.00005986	0.00112142	0.00696899	-	0.00039618	0.00000760	0.00000578	0.00000661	0.00000157
LABOR_M DISTPRI	0.04747342	0.03139986	0.00779214	0.00009893	-	0.00340122	0.00093531	-	-	0.00014574	0.00269180	-	-	0.00095603	0.00001836	0.00001403	0.00001615	0.00000383
LABOR_M DISTSEC	0.01739933	0.01323007	0.00267040	-	-	0.00102282	-	-	-	0.00003592	-	-	-	0.00029669	-	0.00000382	0.00011370	0.00002591
LABOR_M ENERGY	0.17521098	0.06437578	0.02033556	0.00025396	0.00001287	0.01030290	0.00277945	0.00043312	-	0.00051887	0.01025620	0.05391792	0.00753950	0.00289674	0.00005477	0.00005464	0.00119788	0.00028083
LABOR_M CUSTOMER	0.35044746	0.27123370	0.06399391	0.00065170	0.00004644	0.00113874	0.00036328	0.00013261	-	0.00001080	0.00026125	0.00043919	0.00008451	0.00036814	0.00000439	0.00002562	0.01083634	0.00085684
LABOR_M TOTAL	1.00000000	0.58290761	0.14546549	0.00164691	0.00009203	0.03858570	0.01030571	0.00157298	-	0.00169226	0.03109258	0.14299923	0.01803083	0.01087304	0.00019715	0.00019056	0.01298508	0.00136284
LABOR_PROD PRODUCTION	0.63107520	0.31289249	0.07824436	0.00099166	0.00004963	0.03510415	0.00962124	0.00153104	-	0.00151746	0.02761523	0.13455639	0.01714523	0.00981788	0.00018455	0.00014278	0.00134172	0.00031939
LABOR_PROD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD ENERGY	0.36892480	0.13554985	0.04281863	0.00053474	0.00002709	0.02169382	0.00585242	0.00091197	-	0.00109254	0.02159548	0.11352975	0.01587519	0.00609938	0.00011533	0.00011504	0.00252225	0.00059131
LABOR_PROD CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD TOTAL	1.00000000	0.44844234	0.12106299	0.00152640	0.00007672	0.05679797	0.01547366	0.00244301	-	0.00261000	0.04921072	0.24808613	0.03302042	0.01591727	0.00029989	0.00025782	0.00386397	0.00091070
MISC_SERV_REV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV DISTPRI	0.23090081	0.21284287	0.01757550	0.00003313	-	0.00036115	0.00003323	-	-	-	-	-	-	-	-	-	0.00005492	-
MISC_SERV_REV DISTSEC	0.08679695	0.08091547	0.00543456	-	-	0.00009799	-	-	-	-	-	-	-	-	-	-	0.00034893	-
MISC_SERV_REV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV CUSTOMER	0.68230224	0.60969178	0.04992311	0.00008258	0.00009679	0.00004374	0.00000460	0.00005896	-	-	-	-	-	-	-	-	0.02240067	-
MISC_SERV_REV TOTAL	1.00000000	0.90345012	0.07293317	0.00011571	0.00009679	0.00050289	0.00003783	0.00005896	-	-	-	-	-	-	-	-	0.02280452	-

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

Allocation Factor	Total Retail 1	RS 2	GS-SEC 3	GS-PRI 4	GS-SUB 5	LGS-SEC 6	LGS-PRI 7	LGS-SUB 8	LGS-TRA 9	IGS-SEC 10	IGS-PRI 11	IGS-SUB 12	IGS-TRA 13	PS-SEC 14	PS-PRI 15	MW 16	OL 17	SL 18
PROD_DEMAND PRODUCTION	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
PROD_DEMAND BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
PROD_ENERGY PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY ENERGY	1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
PROD_ENERGY CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY TOTAL	1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
RATEBASE PRODUCTION	0.26496409	0.13086097	0.03282263	0.00037611	0.00000899	0.01481483	0.00393663	0.00062573	-	0.00063493	0.01126628	0.05729719	0.00725467	0.00421367	0.00007933	0.00006133	0.00057351	0.00013727
RATEBASE BULKTRAN	0.22545144	0.11144764	0.02793514	0.00032856	0.00001014	0.01258949	0.00337081	0.00053593	-	0.00054077	0.00965325	0.04859066	0.00616178	0.00356610	0.00006712	0.00005192	0.00048598	0.00011615
RATEBASE SUBTRAN	0.06931518	0.03333245	0.00833643	0.00009802	0.00000382	0.00371925	0.00099673	0.00020017	-	0.00015658	0.00287588	0.01848136	-	0.00105697	0.00002030	0.00001544	0.00001759	0.00000419
RATEBASE DISTPRI	0.10362927	0.06855807	0.01705389	0.00020063	-	0.00747811	0.00200809	-	-	0.00031837	0.00576606	-	-	0.00212940	0.00004095	0.00003129	0.00003586	0.00000855
RATEBASE DISTSEC	0.03389387	0.02573897	0.00520781	-	-	0.00200401	-	-	-	0.00006992	-	-	-	0.00058899	-	0.00000759	0.00022506	0.00005151
RATEBASE ENERGY	0.02895961	0.01064371	0.00335715	0.00004061	0.00000178	0.00170578	0.00045751	0.00007133	-	0.00008542	0.00169018	0.00891715	0.00124508	0.00048168	0.00000911	0.00000897	0.00019756	0.00004659
RATEBASE CUSTOMER	0.27378654	0.20409432	0.05018092	0.00051411	0.00002284	0.00093525	0.00028722	0.00011501	-	0.00000863	0.00021022	0.00039362	0.00007592	0.00030337	0.00000355	0.00002172	0.01465523	0.00196462
RATEBASE TOTAL	1.00000000	0.58467612	0.14489397	0.00155804	0.00004757	0.04324672	0.01105699	0.00154817	-	0.00181463	0.03146187	0.13367998	0.01473746	0.01234019	0.00022034	0.00019827	0.01619081	0.00232888
RB_GUP_CWIP PRODUCTION	0.07903522	0.03918634	0.00979924	0.00012419	0.00000622	0.00439641	0.00120495	0.00019175	-	0.00019005	0.00345850	0.01685171	0.00214725	0.00122958	0.00002311	0.00001788	0.00016804	0.00004000
RB_GUP_CWIP BULKTRAN	0.41671182	0.20660929	0.05166635	0.00065481	0.00003277	0.02317999	0.00635310	0.00101097	-	0.00100201	0.01823490	0.08885032	0.01132135	0.00648295	0.00012186	0.00009428	0.00088596	0.00021090
RB_GUP_CWIP SUBTRAN	0.13201767	0.06370674	0.01589441	0.00020187	0.00001301	0.00705843	0.00193772	0.00038950	-	0.00029911	0.00560396	0.03482536	-	0.00197979	0.00003798	0.00002888	0.00003305	0.00000785
RB_GUP_CWIP DISTPRI	0.09061767	0.05993633	0.01487371	0.00018884	-	0.00649228	0.00178533	-	-	0.00027819	0.00513813	-	-	0.00182488	0.00003505	0.00002679	0.00003082	0.00000732
RB_GUP_CWIP DISTSEC	0.03005386	0.02285231	0.00461258	-	-	0.00176671	-	-	-	0.00006205	-	-	-	0.00051247	-	0.00000660	0.00019639	0.00004476
RB_GUP_CWIP ENERGY	0.00902523	0.00331604	0.00104750	0.00001308	0.00000066	0.00053071	0.00014317	0.00002231	-	0.00002673	0.00052830	0.00277735	0.00038836	0.00014921	0.00000282	0.00000281	0.00006170	0.00001447
RB_GUP_CWIP CUSTOMER	0.24253853	0.18102684	0.04440496	0.00049154	0.00003621	0.00082376	0.00025913	0.00010387	-	0.00000765	0.00019010	0.00034426	0.00006673	0.00026372	0.00000308	0.00001887	0.01279038	0.00170743
RB_GUP_CWIP TOTAL	1.00000000	0.57663388	0.14229875	0.00167433	0.00008888	0.04424828	0.01168340	0.00171839	-	0.00186579	0.03315390	0.14364900	0.01392370	0.01244261	0.00022390	0.00019611	0.01416635	0.00203272
RB_GUP_EPIS_D PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D DISTPRI	0.25795198	0.17061456	0.04233947	0.00053754	-	0.01848090	0.00508211	-	-	0.00079190	0.01462620	-	-	0.00519471	0.00009977	0.00007625	0.00008774	0.00002083
RB_GUP_EPIS_D DISTSEC	0.08530191	0.06486173	0.01309188	-	-	0.00501446	-	-	-	0.00017612	-	-	-	0.00145453	-	0.00001872	0.00055743	0.00012704
RB_GUP_EPIS_D ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D CUSTOMER	0.65674611	0.48872813	0.12026505	0.00133981	0.00009894	0.00223833	0.00070334	0.00028389	-	0.00002076	0.00051678	0.00094096	0.00018250	0.00071605	0.00000834	0.00005133	0.03578584	0.00486605
RB_GUP_EPIS_D TOTAL	1.00000000	0.72420443	0.17569639	0.00187735	0.00009894	0.02573368	0.00578546	0.00028389	-	0.00098877	0.01514297	0.00094096	0.00018250	0.00736529	0.00010811	0.00014631	0.03643101	0.00501393
RB_GUP_EPIS_G PRODUCTION	0.29971231	0.14859993	0.03716007	0.00047096	0.00002357	0.01667178	0.00456935	0.00072712	-	0.00072068	0.01311512	0.06390396	0.00814267	0.00466274	0.00008765	0.00006781	0.00063721	0.00015168
RB_GUP_EPIS_G BULKTRAN	0.08333811	0.04131975	0.01033274	0.00013096	0.00000655	0.00463576	0.00127055	0.00020218	-	0.00020039	0.00364679	0.01776916	0.00226415	0.00129652	0.00002437	0.00001885	0.00017718	0.00004218
RB_GUP_EPIS_G SUBTRAN	0.02641839	0.01274852	0.00318067	0.00004040	0.00000260	0.00141248	0.00038776	0.00007794	-	0.00005986	0.00112142	0.00696899	-	0.00039618	0.00000760	0.00000578	0.00000661	0.00000157
RB_GUP_EPIS_G DISTPRI	0.04747342	0.03139986	0.00779214	0.00009893	-	0.00340122	0.00093531	-	-	0.00014574	0.00269180	-	-	0.00095603	0.00001836	0.00001403	0.00001615	0.00000383
RB_GUP_EPIS_G DISTSEC	0.01739933	0.01323007	0.00267040	-	-	0.00102282	-	-	-	0.00003592	-	-	-	0.00029669	-	0.00000382	0.00011370	0.00002591
RB_GUP_EPIS_G ENERGY	0.17521098	0.06437578	0.02033556	0.00025396	0.00001287	0.01030290	0.00277945	0.00043312	-	0.00051887	0.01025620	0.05391792	0.00753950	0.00289674	0.00005477	0.00005464	0.00119788	0.00028083
RB_GUP_EPIS_G CUSTOMER	0.35044746	0.27123370	0.06399391	0.00065170	0.00004644	0.00113874	0.00036328	0.00013261	-	0.00001080	0.00026125	0.00043919	0.00008451	0.00036814	0.00000439	0.00002562	0.01083634	0.00085684
RB_GUP_EPIS_G TOTAL	1.00000000	0.58290761	0.14546549	0.00164691	0.00009203	0.03858570	0.01030571	0.00157298	-	0.00169226	0.03109258	0.14299923	0.01803083	0.01087304	0.00019715	0.00019056	0.01298508	0.00136284
RB_GUP_EPIS_P PRODUCTION	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
RB_GUP_EPIS_P BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
RB_GUP_EPIS_T PRODUCTION	0.01610094	0.00798298	0.00199629	0.00002530	0.00000127	0.00089563	0.00024547	0.00003906	-	0.00003872	0.00070456	0.00343300	0.00043743	0.00025049	0.00000471	0.00000364	0.00003423	0.00000815
RB_GUP_EPIS_T BULKTRAN	0.74718602	0.37046123	0.09264045	0.00117411	0.00005876	0.04156293	0.01139144	0.00181273	-	0.00179666	0.03269613	0.15931326	0.02029977	0.01162426	0.00021851	0.00016905	0.00158858	0.00037815
RB_GUP_EPIS_T SUBTRAN	0.23671304	0.11422877	0.02849933	0.00036196	0.00002333	0.01265605	0.00347441	0.00069838	-	0.00053632	0.01004812	0.06244330	-	0.00354985	0.00006809	0.00005179	0.00005926	0.00001407
RB_GUP_EPIS_T DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T TOTAL	1.00000000	0.49267299	0.12313607	0.00156137	0.00008336	0.05511461	0.01511132	0.00255017	-	0.00237170	0.04344882	0.22518956	0.02073720	0.01542461	0.00029131	0.00022448	0.00168207	0.00040037
RB_GUP-Land_P PRODUCTION	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
RB_GUP-Land_P BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610

Allocation Factor	Total Retail 1	RS 2	GS-SEC 3	GS-PRI 4	GS-SUB 5	LGS-SEC 6	LGS-PRI 7	LGS-SUB 8	LGS-TRA 9	IGS-SEC 10	IGS-PRI 11	IGS-SUB 12	IGS-TRA 13	PS-SEC 14	PS-PRI 15	MW 16	OL 17	SL 18
RB_GUP-Land_T PRODUCTION	0.01690733	0.00838280	0.00209627	0.00002657	0.00000133	0.00094049	0.00025777	0.00004102	-	0.00004065	0.00073985	0.00360494	0.00045934	0.00026303	0.00000494	0.00000383	0.00003595	0.00000856
RB_GUP-Land_T BULKTRAN	0.73452425	0.36418342	0.09107057	0.00115421	0.00005777	0.04085861	0.01119840	0.00178201	-	0.00176621	0.03214206	0.15661355	0.01995577	0.01142728	0.00021481	0.00016618	0.00156166	0.00037174
RB_GUP-Land_T SUBTRAN	0.24856843	0.11994973	0.02992667	0.00038009	0.00002450	0.01328990	0.00364842	0.00073336	-	0.00056319	0.01055137	0.06557066	-	0.00372764	0.00007150	0.00005439	0.00006223	0.00001477
RB_GUP-Land_T DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T TOTAL	1.00000000	0.49251595	0.12309351	0.00156087	0.00008360	0.05508900	0.01510459	0.00255639	-	0.00237005	0.04343328	0.22578916	0.02041511	0.01541796	0.00029125	0.00022439	0.00165983	0.00039507
RB_GUP-Land_D PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D DISTPRI	0.25151119	0.16635450	0.04128230	0.00052412	-	0.01801945	0.00495522	-	-	0.00077213	0.01426099	-	-	0.00506500	0.00009728	0.00007435	0.00008555	0.00002031
RB_GUP-Land_D DISTSEC	0.08604231	0.06542472	0.01320551	-	-	0.00505798	-	-	-	0.00017765	-	-	-	0.00146716	-	0.00001888	0.00056226	0.00012815
RB_GUP-Land_D ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D CUSTOMER	0.66244650	0.49297017	0.12130892	0.00135144	0.00009980	0.00225776	0.00070945	0.00028636	-	0.00002094	0.00052126	0.00094913	0.00018408	0.00072227	0.00000842	0.00005178	0.03609646	0.00490829
RB_GUP-Land_D TOTAL	1.00000000	0.72474938	0.17579673	0.00187556	0.00009980	0.02533519	0.00566466	0.00028636	-	0.00097071	0.01478226	0.00094913	0.00018408	0.00725443	0.00010570	0.00014501	0.03674427	0.00505674
RB_GUP-Land_G PRODUCTION	0.29971231	0.14859993	0.03716007	0.00047096	0.00002357	0.01667178	0.00456935	0.00072712	-	0.00072068	0.01311512	0.06390396	0.00814267	0.00466274	0.00008765	0.00006781	0.00063721	0.00015168
RB_GUP-Land_G BULKTRAN	0.08333811	0.04131975	0.01033274	0.00013096	0.00000655	0.00463576	0.00127055	0.00020218	-	0.00020039	0.00364679	0.01776916	0.00226415	0.00129652	0.00002437	0.00001885	0.00017718	0.00004218
RB_GUP-Land_G SUBTRAN	0.02641839	0.01274852	0.00318067	0.00004040	0.00000260	0.00141248	0.00038776	0.00007794	-	0.00005986	0.00112142	0.00696899	-	0.00039618	0.00000760	0.00000578	0.00000661	0.00000157
RB_GUP-Land_G DISTPRI	0.04747342	0.03139986	0.00779214	0.00009893	-	0.00340122	0.00093531	-	-	0.00014574	0.00269180	-	-	0.00095603	0.00001836	0.00001403	0.00001615	0.00000383
RB_GUP-Land_G DISTSEC	0.01739933	0.01323007	0.00267040	-	-	0.00102282	-	-	-	0.00003592	-	-	-	0.00029669	-	0.00000382	0.00011370	0.00002591
RB_GUP-Land_G ENERGY	0.17521098	0.06437578	0.02033556	0.00025396	0.00001287	0.01030290	0.00277945	0.00043312	-	0.00051887	0.01025620	0.05391792	0.00753950	0.00289674	0.00005477	0.00005464	0.00119788	0.00028083
RB_GUP-Land_G CUSTOMER	0.35044746	0.27123370	0.06399391	0.00065170	0.00004644	0.00113874	0.00036328	0.00013261	-	0.00001080	0.00026125	0.00043919	0.00008451	0.00036814	0.00000439	0.00002562	0.01083634	0.00085684
RB_GUP-Land_G TOTAL	1.00000000	0.58290761	0.14546549	0.00164691	0.00009203	0.03858570	0.01030571	0.00157298	-	0.00169226	0.03109258	0.14299923	0.01803083	0.01087304	0.00019715	0.00019056	0.01298508	0.00136284
RB_GUP_EPIS PRODUCTION	0.32461816	0.16094846	0.04024804	0.00051010	0.00002553	0.01805719	0.00494906	0.00078755	-	0.00078057	0.01420497	0.06921433	0.00881932	0.00505021	0.00009493	0.00007344	0.00069016	0.00016429
RB_GUP_EPIS BULKTRAN	0.20806577	0.10316079	0.02579720	0.00032695	0.00001636	0.01157385	0.00317213	0.00050478	-	0.00050031	0.00910475	0.04436330	0.00565279	0.00323696	0.00006085	0.00004707	0.00044236	0.00010530
RB_GUP_EPIS SUBTRAN	0.06591740	0.03180925	0.00793620	0.00010079	0.00000650	0.00352433	0.00096752	0.00019448	-	0.00014935	0.00279810	0.01738856	-	0.00098853	0.00001896	0.00001442	0.00001650	0.00000392
RB_GUP_EPIS DISTPRI	0.09771876	0.06463313	0.01603927	0.00020363	-	0.00700103	0.00192523	-	-	0.00029999	0.00554077	-	-	0.00196789	0.00003780	0.00002889	0.00003324	0.00000789
RB_GUP_EPIS DISTSEC	0.03240895	0.02464307	0.00497403	-	-	0.00190515	-	-	-	0.00006691	-	-	-	0.00055262	-	0.00000711	0.00021178	0.00004827
RB_GUP_EPIS ENERGY	0.00972982	0.00357492	0.00112927	0.00001410	0.00000071	0.00057214	0.00015435	0.00002405	-	0.00002881	0.00056955	0.00299417	0.00041868	0.00016086	0.00000304	0.00000303	0.00006652	0.00001559
RB_GUP_EPIS CUSTOMER	0.26154114	0.19520993	0.04788404	0.00053005	0.00003905	0.00088830	0.00027943	0.00011201	-	0.00000825	0.00020499	0.00037123	0.00007196	0.00028438	0.00000332	0.00002035	0.01379262	0.00184123
RB_GUP_EPIS TOTAL	1.00000000	0.58397954	0.14400805	0.00168563	0.00008815	0.04352200	0.01144771	0.00162287	-	0.00183419	0.03242314	0.13433159	0.01496276	0.01224146	0.00021890	0.00019432	0.01525319	0.00218650
RB_GUP PRODUCTION	0.32461816	0.16094846	0.04024804	0.00051010	0.00002553	0.01805719	0.00494906	0.00078755	-	0.00078057	0.01420497	0.06921433	0.00881932	0.00505021	0.00009493	0.00007344	0.00069016	0.00016429
RB_GUP BULKTRAN	0.20806577	0.10316079	0.02579720	0.00032695	0.00001636	0.01157385	0.00317213	0.00050478	-	0.00050031	0.00910475	0.04436330	0.00565279	0.00323696	0.00006085	0.00004707	0.00044236	0.00010530
RB_GUP SUBTRAN	0.06591740	0.03180925	0.00793620	0.00010079	0.00000650	0.00352433	0.00096752	0.00019448	-	0.00014935	0.00279810	0.01738856	-	0.00098853	0.00001896	0.00001442	0.00001650	0.00000392
RB_GUP DISTPRI	0.09771876	0.06463313	0.01603927	0.00020363	-	0.00700103	0.00192523	-	-	0.00029999	0.00554077	-	-	0.00196789	0.00003780	0.00002889	0.00003324	0.00000789
RB_GUP DISTSEC	0.03240895	0.02464307	0.00497403	-	-	0.00190515	-	-	-	0.00006691	-	-	-	0.00055262	-	0.00000711	0.00021178	0.00004827
RB_GUP ENERGY	0.00972982	0.00357492	0.00112927	0.00001410	0.00000071	0.00057214	0.00015435	0.00002405	-	0.00002881	0.00056955	0.00299417	0.00041868	0.00016086	0.00000304	0.00000303	0.00006652	0.00001559
RB_GUP CUSTOMER	0.26154114	0.19520993	0.04788404	0.00053005	0.00003905	0.00088830	0.00027943	0.00011201	-	0.00000825	0.00020499	0.00037123	0.00007196	0.00028438	0.00000332	0.00002035	0.01379262	0.00184123
RB_GUP TOTAL	1.00000000	0.58397954	0.14400805	0.00168563	0.00008815	0.04352200	0.01144771	0.00162287	-	0.00183419	0.03242314	0.13433159	0.01496276	0.01224146	0.00021890	0.00019432	0.01525319	0.00218650
REV_RENT PRODUCTION	0.12986507	0.06438822	0.01610142	0.00020407	0.00001021	0.00722387	0.00197989	0.00031506	-	0.00031227	0.00568277	0.02768953	0.00352821	0.00202036	0.00003798	0.00002938	0.00027610	0.00006572
REV_RENT BULKTRAN	0.02590850	0.01284566	0.00321229	0.00004071	0.00000204	0.00144118	0.00039500	0.00006286	-	0.00006230	0.00113373	0.00552415	0.00070389	0.00040307	0.00000758	0.00000586	0.00005508	0.00001311
REV_RENT SUBTRAN	0.00821306	0.00396331	0.00098882	0.00001256	0.00000081	0.00043912	0.00012055	0.00002423	-	0.00001861	0.00034863	0.00216655	-	0.00012317	0.00000236	0.00000180	0.00000206	0.00000049
REV_RENT DISTPRI	0.12801817	0.08467376	0.02101252	0.00026677	-	0.00917183	0.00252219	-	-	0.00039301	0.00725879	-	-	0.00257807	0.00004951	0.00003784	0.00004355	0.00001034
REV_RENT DISTSEC	0.05133611	0.03903487	0.00787891	-	-	0.00301778	-	-	-	0.00010599	-	-	-	0.00087536	-	0.00001127	0.00033547	0.00007646
REV_RENT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REV_RENT CUSTOMER	0.65665909	0.52143259	0.12326649	0.00049820	0.00001967	0.00165572	0.00036845	0.00005644	-	0.00001701	0.00023798	0.00018707	0.00003628	0.00058672	0.00000488	0.00003597	0.00711436	0.00114127
REV_RENT TOTAL	1.00000000	0.72633841	0.17246046	0.00102231	0.00003273	0.02294950	0.00538607	0.00045859	-	0.00090918	0.01466190	0.03556729	0.00426838	0.00658674	0.00010231	0.00012211	0.00782661	0.00130739
REV PRODUCTION	0.30633965	0.14220698	0.04193835	0.00050399	0.00002499	0.02204859	0.00639030	0.00076472	-	0.00085434	0.01787794	0.05724915	0.00869785	0.00660791	0.00011672	0.00009197	0.00075258	0.00021327
REV BULKTRAN	0.05968025	0.01646053	0.01174633	0.00016654	0.00000883	0.00767775	0.00221108	0.00009206	-	0.00028788	0.00530488	0.01027032	0.00243881	0.00255735	0.00004254	0.00004662	0.00028021	0.00008852
REV SUBTRAN	0.01886834	0.00543708	0.00363334	0.00005140	0.00000349	0.00232487	0.00066964	0.00003757	-	0.00008577	0.00162629	0.00418425	-	0.00077373	0.00001317	0.00001409	0.00001041	0.00000326
REV DISTPRI	0.04296395	0.02020634	0.00924852	0.00012072	-	0.00552772	0.00161836	-	-	0.00020386	0.00415555	-	-	0.00179105	0.00003088	0.00002962	0.00002389	0.00000742
REV DISTSEC	0.01347700	0.00823349	0.00294956	-	-	0.00152998	-	-	-	0.00004642	-	-	-	0.00050938	-	0.00000734	0.00015493	0.00004591
REV ENERGY	0.39715840	0.14960392	0.04598757	0.00053428	0.00002705	0.02404296	0.00674300	0.00105802	-	0.00114736	0.02563233	0.11569874	0.01650600	0.00676941	0.00012614	0.00010849	0.00253997	0.00063316
REV CUSTOMER	0.16151242	0.10882230	0.03804015	0.00041200	0.00003085	0.00088711	0.00029829	0.00006498	-	0.00000730	0.00020125	0.00019480	0.00005189	0.00031798	0.00000344	0.00002417	0.01044065	0.00171527
REV TOTAL	1.00000000	0.45097065	0.15354382	0.00178893	0.00009521	0.06403896	0.01793067	0.00201735	-	0.00263293	0.05479824	0.18759726	0.02769454	0.01932681	0.00033289	0.00032229	0.01420265	0.00270681
RSALE PRODUCTION	0.46286997	0.21581431	0.06231455	0.00078743	0.00003879	0.03151627	0.00876081	0.00107792	-	0.00126935	0.02419324	0.09248298	0.01342459	0.00940715	0.00016886	0.00014520	0.00115805	0.00031047
RSALE BULKTRAN	(0.06021468)	(0.04426348)	(0.00252636)	(0.00001220)	(0.00000002)	0.00162122	0.00054912	(0.00019363)	-	0.00002014	0.00041543	(0.01615303)	(0.00072667)	0.00093040	0.00001115	0.00002683	0.00004925	0.00003717
RSALE SUBTRAN	(0.01918086)	(0.01325321)	(0.00075757)	(0.00000373)	(0.00000004)	0.00047744	0.00016187	(0.00007242)	-	0.00000576	0.00012230	(0.00615112)	-	0.00027540	0.00000337	0.00000797	0.00000178	0.00000134
RSALE DISTPRI	0.04648442	0.02137524	0.01027458	0.00013948	-	0.00616806	0.00175364	-	-	0.00023021	0.00441104	-	-	0.00202382	0.00003495	0.00003688	0.00002794	0.00000857
RSALE DISTSEC	0.01448486	0.00865486	0.00326104	-	-	0.00170075	-	-	-	0.00005219	-	-	-	0.00057363	-	0.00000911	0.00018045	0.00005282
RSALE ENERGY	0.38174560	0.14210400	0.04428820	0.00052672	0.00002643	0.02318102	0.00634862	0.00096427	-	0.00111226	0.02382534	0.11319196	0.01619917	0.00659058	0.00012296	0.00011236	0.00252657	0.00062517
RSALE CUSTOMER	0.17381069	0.11481314	0.04181330	0.00048240	0.00003602	0.00098807	0.00032472	0.00006856	-	0.00000821	0.00021528	0.00022581	0.00006036	0.00035772	0.00000391	0.00003003	0.01238536	0.00199780
RSALE TOTAL	1.00000000	0.44524485	0.15866775	0.00192010	0.00010118	0.06565282	0.01789878	0.00184469	-	0.00269812	0.05318263	0.18359661	0.02895745	0.02015871	0.00034519	0.00036838	0.01632940	0.00303335
REVYEC_FXNL PRODUCTION	0.47860747	(0.14621368)	0.04932718	(0.00628048)	(0.00029133)	0.11747540	0.07787115	0.02223889	-	-	0.44234007	(0.09276335)	-	0.02330526	-	(0.00266527)	(0.00579480)	0.00005844
REVYEC_FXNL BULKTRAN	0.06038581	0.02998840	(0.00199983)	0.00009733	0.00000016	0.00604303	0.00488094	(0.00399485)	-	-	0.00759553	0.01620200	-	0.00230498	-	(0.00049244)	(0.00024643)	0.00000700
REVYEC_FXNL SUBTRAN	0.01906677	0.00897902	(0.00059968)	0.00002975	0.00000027	0.00177963	0.00143877	(0.00149417)	-	-	0.00223609	0.00616977	-	0.00068228	-	(0.00014631)	(0.00000888)	0.00000025
REVYEC_FXNL DISTPRI	0.11596600	(0.01448167)	0.00813319	(0.00111247)	-	0.02299114	0.01558736	-	-	-	0.08064984	-	-	0.00501381	-	(0.00067698)	(0.00013983)	0.00000161
REVYEC_FXNL DISTSEC	0.00341808	(0.00586365)	0.00258139	-	-	0.00633946	-	-	-	-	-	-	-	0.00142112	-	(0.00016722)	(0.00090296)	0.00000994
REVYEC_FXNL ENERGY	0.42093185	(0.09627512)	0.03505781	(0.00420106)	(0.00019853)	0.08640614	0.05643017	0.01989413	-	-	0.43561343	(0.11353511)	-	0.01632750	-	(0.00206243)	(0.01264275)	0.00011767
REVYEC_FXNL CUSTOMER	(0.09837598)	(0.07778563)	0.03309873	(0.00384761)	(0.00027055)	0.00368297	0.00288633	0.00141453	-	-	0.00393608	(0.00022650)	-	0.00088621	-	(0.00055120)	(0.06197537)	0.00037602
REVYEC_FXNL TOTAL	1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092

Allocation Factor	Total Retail 1	RS 2	GS-SEC 3	GS-PRI 4	GS-SUB 5	LGS-SEC 6	LGS-PRI 7	LGS-SUB 8	LGS-TRA 9	IGS-SEC 10	IGS-PRI 11	IGS-SUB 12	IGS-TRA 13	PS-SEC 14	PS-PRI 15	MW 16	OL 17	SL 18
REVYEC_EXP_OM PRODUCTION	0.29136813	(0.09222448)	0.03473157	(0.00442244)	(0.00020944)	0.07488453	0.04945208	0.01211961	-	-	0.25709331	(0.04706536)	-	0.01520742	-	(0.00168532)	(0.00657379)	0.00006044
REVYEC_EXP_OM BULKTRAN	0.01329532	(0.00427417)	0.00159798	(0.00020319)	(0.00000961)	0.00342760	0.00226187	0.00056113	-	-	0.01179259	(0.00217800)	-	0.00069383	-	(0.00007640)	(0.00030106)	0.00000275
REVYEC_EXP_OM SUBTRAN	0.00400809	(0.00131832)	0.00049186	(0.00006268)	(0.00000382)	0.00104446	0.00069039	0.00021626	-	-	0.00362643	(0.00085398)	-	0.00021205	-	(0.00002343)	(0.00001124)	0.00000010
REVYEC_EXP_OM DISTPRI	0.02502821	(0.00724391)	0.00270104	(0.00034440)	-	0.00565620	0.00374692	-	-	-	0.01954902	-	-	0.00115321	-	(0.00012874)	(0.00006169)	0.00000056
REVYEC_EXP_OM DISTSEC	(0.00053172)	(0.00304957)	0.00092514	-	-	0.00170035	-	-	-	-	-	-	-	0.00035780	-	(0.00003504)	(0.00043422)	0.00000382
REVYEC_EXP_OM ENERGY	0.73348942	(0.13474906)	0.06412609	(0.00804625)	(0.00038568)	0.15618086	0.10152163	0.02434880	-	-	0.67845101	(0.13393691)	-	0.03189050	-	(0.00458508)	(0.04170425)	0.00037776
REVYEC_EXP_OM CUSTOMER	(0.06665744)	(0.05879282)	0.02102512	(0.00223559)	(0.00015144)	0.00182377	0.00142185	0.00081273	-	-	0.00185869	(0.00011895)	-	0.00042634	-	(0.00022784)	(0.03262478)	0.00012549
REVYEC_EXP_OM TOTAL	1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092
TDOMX PRODUCTION	(0.00000000)	0.00000000	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	(0.00000000)	-	(0.00000000)	0.00000000	0.00000000	(0.00000000)	(0.00000000)	(0.00000000)	(0.00000000)	0.00000000	(0.00000000)
TDOMX BULKTRAN	0.02233724	0.01107499	0.00276950	0.00003510	0.00000176	0.00124253	0.00034055	0.00005419	-	0.00005371	0.00097746	0.00476269	0.00060686	0.00034751	0.00000653	0.00000505	0.00004749	0.00001130
TDOMX SUBTRAN	0.00708096	0.00341700	0.00085252	0.00001083	0.00000070	0.00037859	0.00010393	0.00002089	-	0.00001604	0.00030058	0.00186791	-	0.00010619	0.00000204	0.00000155	0.00000177	0.00000042
TDOMX DISTPRI	0.14475766	0.09574559	0.02376009	0.00030166	-	0.01037112	0.00285198	-	-	0.00044440	0.00820794	-	-	0.00291517	0.00005599	0.00004279	0.00004924	0.00001169
TDOMX DISTSEC	0.05305466	0.04034162	0.00814267	-	-	0.00311881	-	-	-	0.00010954	-	-	-	0.00090466	-	0.00001164	0.00034670	0.00007902
TDOMX ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDOMX CUSTOMER	0.77276948	0.60500154	0.14973763	0.00187975	0.00013712	0.00289571	0.00099734	0.00039345	-	0.00002657	0.00072956	0.00130408	0.00025293	0.00091662	0.00001188	0.00006675	0.00587855	0.00253999
TDOMX TOTAL	1.00000000	0.75558075	0.18526241	0.00222733	0.00013958	0.01800676	0.00429381	0.00046853	-	0.00065026	0.01021553	0.00793469	0.00085979	0.00519016	0.00007644	0.00012779	0.00632375	0.00264243
TDPLANT PRODUCTION	0.00684037	0.00339151	0.00084811	0.00001075	0.00000054	0.00038050	0.00010429	0.00001660	-	0.00001645	0.00029933	0.00145849	0.00018584	0.00010642	0.00000200	0.00000155	0.00001454	0.00000346
TDPLANT BULKTRAN	0.31743648	0.15738773	0.03935761	0.00049881	0.00002497	0.01765770	0.00483957	0.00077012	-	0.00076330	0.01389071	0.06768307	0.00862421	0.00493848	0.00009283	0.00007182	0.00067490	0.00016065
TDPLANT SUBTRAN	0.10056580	0.04852925	0.01210773	0.00015378	0.00000991	0.00537683	0.00147608	0.00029670	-	0.00022785	0.00426887	0.02652857	-	0.00150813	0.00002893	0.00002200	0.00002518	0.00000598
TDPLANT DISTPRI	0.14836298	0.09813022	0.02435186	0.00030917	-	0.01062942	0.00292302	-	-	0.00045547	0.00841236	-	-	0.00298778	0.00005738	0.00004386	0.00005047	0.00001198
TDPLANT DISTSEC	0.04906202	0.03730570	0.00752989	-	-	0.00288410	-	-	-	0.00010130	-	-	-	0.00083658	-	0.00001077	0.00032061	0.00007307
TDPLANT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDPLANT CUSTOMER	0.37773236	0.28109558	0.06917133	0.00077060	0.00005691	0.00128739	0.00040453	0.00016328	-	0.00001194	0.00029723	0.00054120	0.00010497	0.00041184	0.00000480	0.00002953	0.02058249	0.00279874
TDPLANT TOTAL	1.00000000	0.62584000	0.15336653	0.00174311	0.00009232	0.03821595	0.00974748	0.00124670	-	0.00157630	0.02716850	0.09621133	0.00891501	0.01078923	0.00018594	0.00017952	0.02166818	0.00305389
TOTMXEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP DISTPRI	0.12892727	0.08527506	0.02116174	0.00026867	-	0.00923696	0.00254010	-	-	0.00039580	0.00731034	-	-	0.00259637	0.00004987	0.00003811	0.00004385	0.00001041
TOTMXEXP DISTSEC	0.05358984	0.04074856	0.00822481	-	-	0.00315027	-	-	-	0.00011064	-	-	-	0.00091379	-	0.00001176	0.00035020	0.00007981
TOTMXEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP CUSTOMER	0.81748288	0.65813172	0.15434538	0.00040229	0.00000378	0.00191029	0.00037312	0.00001084	-	0.00002021	0.00022457	0.00003591	0.00000697	0.00069709	0.00000520	0.00004079	0.00067571	0.00059902
TOTMXEXP TOTAL	1.00000000	0.78415535	0.18373192	0.00067096	0.00000378	0.01429752	0.00291322	0.00001084	-	0.00052665	0.00753490	0.00003591	0.00000697	0.00420726	0.00005506	0.00009066	0.00106976	0.00068925
TOTOHLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES DISTPRI	0.12042563	0.07965190	0.01976630	0.00025095	-	0.00862786	0.00237260	-	-	0.00036970	0.00682828	-	-	0.00242517	0.00004658	0.00003560	0.00004096	0.00000973
TOTOHLINES DISTSEC	0.05395049	0.04102279	0.00828016	-	-	0.00317147	-	-	-	0.00011139	-	-	-	0.00091994	-	0.00001184	0.00035255	0.00008035
TOTOHLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES CUSTOMER	0.82562388	0.66582734	0.15592569	0.00036384	-	0.00190005	0.00035879	-	-	0.00002021	0.00021224	-	-	0.00069736	0.00000505	0.00004043	-	0.00027288
TOTOHLINES TOTAL	1.00000000	0.78650203	0.18397215	0.00061479	-	0.01369938	0.00273139	-	-	0.00050130	0.00704052	-	-	0.00404247	0.00005163	0.00008786	0.00039352	0.00036296
TOTOX234 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 CUSTOMER	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563
TOTOX234 TOTAL	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563
TOTOXEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP DISTPRI	0.24388717	0.16131182	0.04003091	0.00050823	-	0.01747323	0.00480501	-	-	0.00074872	0.01382870	-	-	0.00491147	0.00009433	0.00007209	0.00008296	0.00001970
TOTOXEXP DISTSEC	0.05951858	0.04525664	0.00913473	-	-	0.00349879	-	-	-	0.00012288	-	-	-	0.00101488	-	0.00001306	0.00038894	0.00008864
TOTOXEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP CUSTOMER	0.69659426	0.46176706	0.15362358	0.00899871	0.00077418	0.00791912	0.00403912	0.00222136	-	0.00006033	0.00317742	0.00736276	0.00142800	0.00208126	0.00004467	0.00019752	0.03093650	0.01196266
TOTOXEXP TOTAL	1.00000000	0.66833552	0.20278922	0.00950694	0.00077418	0.02889114	0.00884413	0.00222136	-	0.00093193	0.01700612	0.00736276	0.00142800	0.00800762	0.00013900	0.00028268	0.03140840	0.01207100
TOTUGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES DISTPRI	0.28486221	0.18841353	0.04675643	0.00059362	-	0.02040887	0.00561229	-	-	0.00087451	0.01615204	-	-	0.00573664	0.00011018	0.00008420	0.00009690	0.00002301
TOTUGLINES DISTSEC	0.03650092	0.02775451	0.00560205	-	-	0.00214570	-	-	-	0.00007536	-	-	-	0.00062240	-	0.00000801	0.00023852	0.00005436
TOTUGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES CUSTOMER	0.67863687	0.54728914	0.12816601	0.00029907	-	0.00156178	0.00029491	-	-	0.00001661	0.00017445	-	-	0.00057321	0.00000415	0.00003323	-	0.00022430
TOTUGLINES TOTAL	1.00000000	0.76345718	0.18052450	0.00089268	-	0.02411636	0.00590720	-	-	0.00096649	0.01632649	-	-	0.00693224	0.00011433	0.00012544	0.00033542	0.00030167
TRAN_LSE PRODUCTION	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
TRAN_LSE BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRAN_LSE TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610

Allocation Factor	Total Retail 1	RS 2	GS-SEC 3	GS-PRI 4	GS-SUB 5	LGS-SEC 6	LGS-PRI 7	LGS-SUB 8	LGS-TRA 9	IGS-SEC 10	IGS-PRI 11	IGS-SUB 12	IGS-TRA 13	PS-SEC 14	PS-PRI 15	MW 16	OL 17	SL 18
TRANS_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL BULKTRAN	0.75930000	0.37646745	0.09414241	0.00119315	0.00005972	0.04223678	0.01157612	0.00184212	-	0.00182579	0.03322623	0.16189618	0.02062888	0.01181273	0.00022205	0.00017179	0.00161433	0.00038428
TRANS_TOTAL SUBTRAN	0.24070000	0.11615273	0.02897934	0.00036805	0.00002373	0.01286921	0.00353293	0.00071015	-	0.00054536	0.01021736	0.06349503	-	0.00360964	0.00006924	0.00005266	0.00006026	0.00001431
TRANS_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL TOTAL	1.00000000	0.49262018	0.12312176	0.00156120	0.00008344	0.05510599	0.01510906	0.00255226	-	0.00237115	0.04344359	0.22539121	0.02062888	0.01542237	0.00029129	0.00022445	0.00167459	0.00039859
WEATHER_FXNL PRODUCTION	0.47643456	0.41837021	0.03400511	0.00018058	-	0.01491427	0.00429176	-	-	-	-	-	-	0.00455384	0.00011878	-	-	-
WEATHER_FXNL BULKTRAN	(0.08569465)	(0.08580766)	(0.00137864)	(0.00000280)	-	0.00076720	0.00026901	-	-	-	-	-	-	0.00045039	0.00000784	-	-	-
WEATHER_FXNL SUBTRAN	(0.02566556)	(0.02569222)	(0.00041341)	(0.00000086)	-	0.00022594	0.00007930	-	-	-	-	-	-	0.00013332	0.00000237	-	-	-
WEATHER_FXNL DISTPRI	0.05185838	0.04143730	0.00560685	0.00003199	-	0.00291888	0.00085908	-	-	-	-	-	-	0.00097970	0.00002459	-	-	-
WEATHER_FXNL DISTSEC	0.01964009	0.01677801	0.00177956	-	-	0.00080484	-	-	-	-	-	-	-	0.00027769	-	-	-	-
WEATHER_FXNL ENERGY	0.31712362	0.27547793	0.02416811	0.00012079	-	0.01096983	0.00311007	-	-	-	-	-	-	0.00319039	0.00008650	-	-	-
WEATHER_FXNL CUSTOMER	0.24630356	0.22257281	0.02281756	0.00011063	-	0.00046758	0.00015908	-	-	-	-	-	-	0.00017317	0.00000275	-	-	-
WEATHER_FXNL TOTAL	1.00000000	0.86313638	0.08658514	0.00044034	-	0.03106853	0.00876829	-	-	-	-	-	-	0.00975849	0.00024283	-	-	-
WEATHER_FXNL_OM PRODUCTION	0.30323643	0.26388759	0.02394321	0.00012716	-	0.00950708	0.00272548	-	-	-	-	-	-	0.00297153	0.00007438	-	-	-
WEATHER_FXNL_OM BULKTRAN	0.01403620	0.01222995	0.00110162	0.00000584	-	0.00043516	0.00012466	-	-	-	-	-	-	0.00013557	0.00000340	-	-	-
WEATHER_FXNL_OM SUBTRAN	0.00432622	0.00377219	0.00033908	0.00000180	-	0.00013260	0.00003805	-	-	-	-	-	-	0.00004144	0.00000106	-	-	-
WEATHER_FXNL_OM DISTPRI	0.02375508	0.02072744	0.00186204	0.00000990	-	0.00071809	0.00020651	-	-	-	-	-	-	0.00022534	0.00000577	-	-	-
WEATHER_FXNL_OM DISTSEC	0.00964947	0.00872591	0.00063777	-	-	0.00021587	-	-	-	-	-	-	-	0.00006991	-	-	-	-
WEATHER_FXNL_OM ENERGY	0.46181599	0.38556579	0.04420716	0.00023135	-	0.01982819	0.00559522	-	-	-	-	-	-	0.00623140	0.00015688	-	-	-
WEATHER_FXNL_OM CUSTOMER	0.18318062	0.16822752	0.01449427	0.00006428	-	0.00023154	0.00007836	-	-	-	-	-	-	0.00008331	0.00000134	-	-	-
WEATHER_FXNL_OM TOTAL	1.00000000	0.86313638	0.08658514	0.00044034	-	0.03106853	0.00876829	-	-	-	-	-	-	0.00975849	0.00024283	-	-	-

INPUTS FROM WORKPAPERS

ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
CPG - 12 CP	Same as CPT	995,051	493,355	123,372	1,564	78	55,351	15,170	2,414	0	2,393	43,542	212,162	27,034	15,480	291	225	2,116	504
PROD_DEMAND	PRODUCTION	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
PROD_DEMAND	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
ENER		5,845,633,541	2,147,794,745	678,463,477	8,473,031	429,224	343,739,682	92,731,919	14,450,272	0	17,311,361	342,181,633	1,798,885,018	251,543,195	96,645,033	1,827,477	1,822,862	39,965,215	9,369,397
PROD_ENERGY	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	ENERGY	1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
PROD_ENERGY	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	TOTAL	1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
CPT - 12 CP	Same as CPG	995,051	493,355	123,372	1,564	78	55,351	15,170	2,414	0	2,393	43,542	212,162	27,034	15,480	291	225	2,116	504
BULK_TRANS	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	BULKTRAN	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
BULK_TRANS	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
CPST - 12 CP		787,897	380,209	94,860	1,205	78	42,126	11,565	2,325	0	1,785	33,445	207,842	0	11,816	227	172	197	47
SUB_TRANS	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	SUBTRAN	1.00000000	0.48256223	0.12039610	0.00152910	0.00009858	0.05346578	0.01467774	0.00295033	-	0.00226572	0.04244854	0.26379322	-	0.01499644	0.00028766	0.00021880	0.00025034	0.00005944
SUB_TRANS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	TOTAL	1.00000000	0.48256223	0.12039610	0.00152910	0.00009858	0.05346578	0.01467774	0.00295033	-	0.00226572	0.04244854	0.26379322	-	0.01499644	0.00028766	0.00021880	0.00025034	0.00005944
CPD - 12 CP		740,472	489,763	121,539	1,543	0	53,051	14,589	0	0	2,273	41,986	0	0	14,912	286	219	252	60
DIST_CPD	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	DISTPRI	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
DIST_CPD	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	TOTAL	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
SECDEM	**(NCP + SNCP) / 2**	1,467,080	1,115,536	225,163	0	0	86,242	0	0	0	3,029	0	0	0	25,016	0	322	9,587	2,185
DISTSEC	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTSEC	1.00000000	0.76037844	0.15347697	-	-	0.05878480	-	-	-	0.00206465	-	-	-	0.01705156	-	0.00021948	0.00653475	0.00148935
DISTSEC	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	TOTAL	1.00000000	0.76037844	0.15347697	-	-	0.05878480	-	-	-	0.00206465	-	-	-	0.01705156	-	0.00021948	0.00653475	0.00148935
TOTCUST		217,974	131,760	30,856	72	3	376	71	7	0	4	42	22	3	138	1	8	54,557	54
CUST_TOTAL	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	CUSTOMER	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
CUST_TOTAL	TOTAL	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
PRICUST	TOTCust excl Sub. & Tran.	217,939	131,760	30,856	72	0	376	71	0	0	4	42	0	0	138	1	8	54,557	54
DIST_PCUST	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	CUSTOMER	1.00000000	0.60457284	0.14158090	0.00033037	-	0.00172525	0.00032578	-	-	0.00001835	0.00019271	-	-	0.00063320	0.00000459	0.00003671	0.25033151	0.00024778
DIST_PCUST	TOTAL	1.00000000	0.60457284	0.14158090	0.00033037	-	0.00172525	0.00032578	-	-	0.00001835	0.00019271	-	-	0.00063320	0.00000459	0.00003671	0.25033151	0.00024778
SECCUST	TOTCust excl Pri., Sub. & Tran.	217,753	131,760	30,856	0	0	376	0	0	0	4	0	0	0	138	0	8	54,557	54
DIST_SERV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV	CUSTOMER	1.00000000	0.60508925	0.14170184	-	-	0.00172673	-	-	-	0.00001837	-	-	-	0.00063375	-	0.00003674	0.25054534	0.00024799
DIST_SERV	TOTAL	1.00000000	0.60508925	0.14170184	-	-	0.00172673	-	-	-	0.00001837	-	-	-	0.00063375	-	0.00003674	0.25054534	0.00024799

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
METER			31,726,882	14,333,232	11,159,174	1,513,728	132,803	1,173,305	663,375	381,053	0	8,379	527,606	1,263,008	244,959	289,069	7,247	29,944	0	0
DIST_METERS	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS	CUSTOMER		1.00000000	0.45176932	0.35172615	0.04771121	0.00418582	0.03698142	0.02090893	0.01201041	-	0.00026410	0.01662962	0.03980877	0.00772087	0.00911117	0.00022842	0.00094381	-	-
DIST_METERS	TOTAL		1.00000000	0.45176932	0.35172615	0.04771121	0.00418582	0.03698142	0.02090893	0.01201041	-	0.00026410	0.01662962	0.03980877	0.00772087	0.00911117	0.00022842	0.00094381	-	-
DIR371			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
DIST_OL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OL	CUSTOMER		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIST_OL	TOTAL		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000	-
DIR373			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
DIST_SL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	CUSTOMER		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIST_SL	TOTAL		1.00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.00000000
DIR902		Weighted TOTCUST	359,362	263,520	92,568	252	11	1,692	355	35	0	24	252	132	18	483	4	16	0	0
CUST_902	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902	CUSTOMER		1.00000000	0.73329957	0.25758984	0.00070124	0.00003061	0.00470834	0.00098786	0.00009739	-	0.00006679	0.00070124	0.00036732	0.00005009	0.00134405	0.00001113	0.00004452	-	-
CUST_902	TOTAL		1.00000000	0.73329957	0.25758984	0.00070124	0.00003061	0.00470834	0.00098786	0.00009739	-	0.00006679	0.00070124	0.00036732	0.00005009	0.00134405	0.00001113	0.00004452	-	-
DIR903		Calculated	2,253,195	1,902,048	342,263	799	33	4,170	788	78	0	44	466	244	33	1,531	11	88	0	599
CUST_903	PRODUCTION	Weighted	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	BULKTRAN	Average	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	CUSTOMER		1.00000000	0.84415597	0.15190119	0.00035461	0.00001465	0.00185071	0.00034973	0.00003462	-	0.00001953	0.00020682	0.00010829	0.00001465	0.00067948	0.00000488	0.00003906	-	0.00026584
CUST_903	TOTAL		1.00000000	0.84415597	0.15190119	0.00035461	0.00001465	0.00185071	0.00034973	0.00003462	-	0.00001953	0.00020682	0.00010829	0.00001465	0.00067948	0.00000488	0.00003906	-	0.00026584
CUST451		Spread by class; alloc. to	248,465	224,475	18,121	29	24	125	9	15	0	0	0	0	0	0	0	0	5,666	0
CUST_451	PRODUCTION	functions below:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	BULKTRAN	MISC_SERV_REV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	CUSTOMER		1.00000000	0.90345012	0.07293317	0.00011571	0.00009679	0.00050289	0.00003783	0.00005896	-	-	-	-	-	-	-	-	0.02280452	-
CUST_451	TOTAL		1.00000000	0.90345012	0.07293317	0.00011571	0.00009679	0.00050289	0.00003783	0.00005896	-	-	-	-	-	-	-	-	0.02280452	-
CUSTDEP		Spread by class; alloc. to	35,277,584	23,034,759	5,040,481	287,254	74,000	1,154,552	803,460	116,556	0	70,530	2,410,767	1,803,187	337,218	28,410	0	0	116,409	0
CUST_DEP	PRODUCTION	functions below:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	BULKTRAN	CUST_DEP_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	CUSTOMER		1.00000000	0.65295738	0.14288056	0.00814268	0.00209765	0.03272765	0.02277538	0.00330395	-	0.00199929	0.06833709	0.05111424	0.00955899	0.00080533	-	-	0.00329981	-
CUST_DEP	TOTAL		1.00000000	0.65295738	0.14288056	0.00814268	0.00209765	0.03272765	0.02277538	0.00330395	-	0.00199929	0.06833709	0.05111424	0.00955899	0.00080533	-	-	0.00329981	-
FORF DISCOUNTS		Spread by class; alloc. to	1,803,105	-28,713	757,869	12,601	1,298	166,247	149,363	18,635	0	20,357	325,609	360,555	14,817	0	0	0	4,467	0
FORF_DISC	PRODUCTION	functions below:	1.00000000	(0.01592420)	0.42031329	0.00698850	0.00071987	0.09220040	0.08283655	0.01033495	-	0.01128997	0.18058238	0.19996340	0.00821749	-	-	-	0.00247739	-
FORF_DISC	BULKTRAN	FORF_DISC_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	TOTAL		1.00000000	(0.01592420)	0.42031329	0.00698850	0.00071987	0.09220040	0.08283655	0.01033495	-	0.01128997	0.18058238	0.19996340	0.00821749	-	-	-	0.00247739	-
YEAR END CUST ADJ		Spread by class; alloc. to	1,882,916	(567,986)	236,492	(28,836)	(1,431)	460,783	299,562	71,661	-	-	1,830,893	(346,745)	-	94,035	-	(12,732)	(153,855)	1,075
REVYEC	PRODUCTION	functions below:	1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092
REVYEC	BULKTRAN	REVYEC_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVYEC	TOTAL		1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
FUELR		Set to Energy Allocator	5,845,633,541	2,147,794,745	678,463,477	8,473,031	429,224	343,739,682	92,731,919	14,450,272	-	17,311,361	342,181,633	1,798,885,018	251,543,195	96,645,033	1,827,477	1,822,862	39,965,215	9,369,397
FUELREV	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	ENERGY		1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
FUELREV	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV	TOTAL		1.00000000	0.36741864	0.11606329	0.00144946	0.00007343	0.05880281	0.01586345	0.00247198	-	0.00296142	0.05853628	0.30773140	0.04303096	0.01653286	0.00031262	0.00031183	0.00683676	0.00160280
WEATHER		Spread by class; alloc. to	12,333,767	10,645,723	1,067,921	5,431	-	383,192	108,146	-	-	-	-	-	-	120,359	2,995	-	-	-
WEATHER_NORM	PRODUCTION	functions below:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	BULKTRAN	WEATHER_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	ENERGY		1.00000000	0.86313638	0.08658514	0.00044034	-	0.03106853	0.00876829	-	-	-	-	-	-	0.00975849	0.00024283	-	-	-
WEATHER_NORM	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER_NORM	TOTAL		1.00000000	0.86313638	0.08658514	0.00044034	-	0.03106853	0.00876829	-	-	-	-	-	-	0.00975849	0.00024283	-	-	-
CUSTOMER SPEC ADJ		Spread by class; alloc. to	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	PRODUCTION	functions below:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	BULKTRAN	CUST_SPEC_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	TOTAL		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

INTERNALLY DERIVED

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Bulk Transmission Plant		$603,025,150																		
Subtransmission Plant		$191,206,935																		
Total Transmisison Plant		$794,232,085																		
BULK_TRANS	BULKTRAN	75.93%	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
SUB_TRANS	SUBTRAN	24.07%	1.00000000	0.48256223	0.12039610	0.00152910	0.00009858	0.05346578	0.01467774	0.00295033	-	0.00226572	0.04244854	0.26379322	-	0.01499644	0.00028766	0.00021880	0.00025034	0.00005944
TRANS_TOTAL	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	BULKTRAN		0.75930000	0.38	0.09414241	0.00119315	0.00005972	0.04223678	0.01157612	0.00184212	-	0.00182579	0.03322623	0.16189618	0.02062888	0.01181273	0.00022205	0.00017179	0.00161433	0.00038428
TRANS_TOTAL	SUBTRAN		0.24070000	0.12	0.02897934	0.00036805	0.00002373	0.01286921	0.00353293	0.00071015	-	0.00054536	0.01021736	0.06349503	-	0.00360964	0.00006924	0.00005266	0.00006026	0.00001431
TRANS_TOTAL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	TOTAL		1.00000000	0.49262018	0.12312176	0.00156120	0.00008344	0.05510599	0.01510906	0.00255226	-	0.00237115	0.04344359	0.22539121	0.02062888	0.01542237	0.00029129	0.00022445	0.00167459	0.00039859
DIST_CPD	DISTPRI	57.25%	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
DISTSEC	DISTSEC	42.75%	1.00000000	0.76037844	0.15347697	-	-	0.05878480	-	-	-	0.00206465	-	-	-	0.01705156	-	0.00021948	0.00653475	0.00148935
DIST_PCUST Excl OL	CUSTOMER																			
DIST_POLES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	DISTPRI		0.57249889	0.38	0.09396826	0.00119301	-	0.04101652	0.01127925	-	-	0.00175754	0.03246139	-	-	0.01152915	0.00022143	0.00016923	0.00019473	0.00004623
DIST_POLES	DISTSEC		0.42750111	0.33	0.06561158	-	-	0.02513057	-	-	-	0.00088264	-	-	-	0.00728956	-	0.00009383	0.00279361	0.00063670
DIST_POLES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	TOTAL		1.00000000	0.70372477	0.15957984	0.00119301	-	0.06614709	0.01127925	-	-	0.00264018	0.03246139	-	-	0.01881871	0.00022143	0.00026306	0.00298835	0.00068293
DIST_CPD	DISTPRI	12.04%	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
DISTSEC	DISTSEC	5.40%	1.00000000	0.76037844	0.15347697	-	-	0.05878480	-	-	-	0.00206465	-	-	-	0.01705156	-	0.00021948	0.00653475	0.00148935
DIST_PCUST Excl OL	CUSTOMER	82.56%	1.00000000	0.80645359	0.18885801	0.00044069	-	0.00230136	0.00043456	-	-	0.00002448	0.00025707	-	-	0.00084465	0.00000612	0.00004897	-	0.00033051
DIST_OHLINES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	DISTPRI		0.12042563	0.07965190	0.01976630	0.00025095	-	0.00862786	0.00237260	-	-	0.00036970	0.00682828	-	-	0.00242517	0.00004658	0.00003560	0.00004096	0.00000973
DIST_OHLINES	DISTSEC		0.05395049	0.04102279	0.00828016	-	-	0.00317147	-	-	-	0.00011139	-	-	-	0.00091994	-	0.00001184	0.00035255	0.00008035
DIST_OHLINES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHLINES	CUSTOMER		0.82562388	0.66582734	0.15592569	0.00036384	-	0.00190005	0.00035879	-	-	0.00002021	0.00021224	-	-	0.00069736	0.00000505	0.00004043	-	0.00027288
DIST_OHLINES	TOTAL		1.00000000	0.78650203	0.18397215	0.00061479	-	0.01369938	0.00273139	-	-	0.00050130	0.00704052	-	-	0.00404247	0.00005163	0.00008786	0.00039352	0.00036296
DIST_CPD	DISTPRI	28.49%	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
DISTSEC	DISTSEC	3.65%	1.00000000	0.76037844	0.15347697	-	-	0.05878480	-	-	-	0.00206465	-	-	-	0.01705156	-	0.00021948	0.00653475	0.00148935
DIST_PCUST Excl OL	CUSTOMER	67.86%	1.00000000	0.80645359	0.18885801	0.00044069	-	0.00230136	0.00043456	-	-	0.00002448	0.00025707	-	-	0.00084465	0.00000612	0.00004897	-	0.00033051
DIST_UGLINES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	DISTPRI		0.28486221	0.18841353	0.04675643	0.00059362	-	0.02040887	0.00561229	-	-	0.00087451	0.01615204	-	-	0.00573664	0.00011018	0.00008420	0.00009690	0.00002301
DIST_UGLINES	DISTSEC		0.03650092	0.02775451	0.00560205	-	-	0.00214570	-	-	-	0.00007536	-	-	-	0.00062240	-	0.00000801	0.00023852	0.00005436
DIST_UGLINES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES	CUSTOMER		0.67863687	0.54728914	0.12816601	0.00029907	-	0.00156178	0.00029491	-	-	0.00001661	0.00017445	-	-	0.00057321	0.00000415	0.00003323	-	0.00022430
DIST_UGLINES	TOTAL		1.00000000	0.76345718	0.18052450	0.00089268	-	0.02411636	0.00590720	-	-	0.00096649	0.01632649	-	-	0.00693224	0.00011433	0.00012544	0.00033542	0.00030167
DIST_CPD	DISTPRI	22.86%	1.00000000	0.66141987	0.16413701	0.00208387	-	0.07164472	0.01970178	-	-	0.00306995	0.05670123	-	-	0.02013829	0.00038677	0.00029559	0.00034015	0.00008076
DISTSEC	DISTSEC	36.63%	1.00000000	0.76037844	0.15347697	-	-	0.05878480	-	-	-	0.00206465	-	-	-	0.01705156	-	0.00021948	0.00653475	0.00148935
DIST_SERV EXCL OL	CUSTOMER	40.51%	1.00000000	0.80737273	0.18907326	-	-	0.00230398	-	-	-	0.00002451	-	-	-	0.00084561	-	0.00004902	-	0.00033089
DIST_TRANSF	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	DISTPRI		0.22862971	0.15122024	0.03752660	0.00047643	-	0.01638011	0.00450441	-	-	0.00070188	0.01296359	-	-	0.00460421	0.00008843	0.00006758	0.00007777	0.00001846
DIST_TRANSF	DISTSEC		0.36631915	0.27854118	0.05622155	-	-	0.02153400	-	-	-	0.00075632	-	-	-	0.00624631	-	0.00008040	0.00239380	0.00054558
DIST_TRANSF	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF	CUSTOMER		0.40505114	0.32702724	0.07658434	-	-	0.00093323	-	-	-	0.00000993	-	-	-	0.00034251	-	0.00001986	-	0.00013403
DIST_TRANSF	TOTAL		1.00000000	0.75678866	0.17033249	0.00047643	-	0.03884734	0.00450441	-	-	0.00146813	0.01296359	-	-	0.01119304	0.00008843	0.00016784	0.00247157	0.00069807

Show under production as it is capturing load (LSE) charges for transmission service, whereas the bulktran and subtran buckets are capturing the costs and revenues as a transmission owner (TO).

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
TRAN_LSE	PRODUCTION	Same as BULK_TRA	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
TRAN_LSE	BULKTRAN																			
TRAN_LSE	SUBTRAN																			
TRAN_LSE	DISTPRI																			
TRAN_LSE	DISTSEC																			
TRAN_LSE	ENERGY																			
TRAN_LSE	CUSTOMER																			
TRAN_LSE	TOTAL		1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
Production EPIS	PRODUCTION		886,000,666	439,286,723	109,851,496	1,392,240	69,680	49,284,624	13,507,774	2,149,503	-	2,130,448	38,770,524	188,911,001	24,071,123	13,783,859	259,103	200,452	1,883,710	448,404
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		886,000,666	439,286,723	109,851,496	1,392,240	69,680	49,284,624	13,507,774	2,149,503	-	2,130,448	38,770,524	188,911,001	24,071,123	13,783,859	259,103	200,452	1,883,710	448,404
RB_GUP_EPIS_P	PRODUCTION		1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
RB_GUP_EPIS_P	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_P	TOTAL		1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
Transmission EPIS	PRODUCTION		12,793,807	6,343,279	1,586,250	20,104	1,006	711,668	195,052	31,039	-	30,764	559,844	2,727,866	347,586	199,038	3,741	2,895	27,201	6,475
	BULKTRAN		593,714,036	294,368,508	73,612,106	932,948	46,693	33,025,904	9,051,636	1,440,394	-	1,427,625	25,980,346	126,590,326	16,130,195	9,236,641	173,627	134,324	1,262,285	300,478
	SUBTRAN		188,092,194	90,766,188	22,645,567	287,612	18,542	10,056,495	2,760,768	554,935	-	426,164	7,984,239	49,617,445	-	2,820,712	54,106	41,154	47,086	11,179
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		794,600,037	391,477,975	97,843,924	1,240,664	66,241	43,794,067	12,007,455	2,026,368	-	1,884,553	34,524,430	178,935,636	16,477,781	12,256,392	231,474	178,372	1,336,572	318,132
RB_GUP_EPIS_T	PRODUCTION		0.01610094	0.00798298	0.00199629	0.00002530	0.00000127	0.00089563	0.00024547	0.00003906	-	0.00003872	0.00070456	0.00343300	0.00043743	0.00025049	0.00000471	0.00000364	0.00003423	0.00000815
RB_GUP_EPIS_T	BULKTRAN		0.74718602	0.37046123	0.09264045	0.00117411	0.00005876	0.04156293	0.01139144	0.00181273	-	0.00179666	0.03269613	0.15931326	0.02029977	0.01162426	0.00021851	0.00016905	0.00158858	0.00037815
RB_GUP_EPIS_T	SUBTRAN		0.23671304	0.11422877	0.02849933	0.00036196	0.00002333	0.01265605	0.00347441	0.00069838	-	0.00053632	0.01004812	0.06244330	-	0.00354985	0.00006809	0.00005179	0.00005926	0.00001407
RB_GUP_EPIS_T	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_T	TOTAL		1.00000000	0.49267299	0.12313607	0.00156137	0.00008336	0.05511461	0.01511132	0.00255017	-	0.00237170	0.04344882	0.22518956	0.02073720	0.01542461	0.00029131	0.00022448	0.00168207	0.00040037
Distribution EPIS	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		277,489,158	183,536,843	45,546,242	578,251	-	19,880,633	5,467,031	-	-	851,878	15,733,978	-	-	5,588,157	107,326	82,024	94,387	22,410
	DISTSEC		91,762,640	69,774,333	14,083,452	-	-	5,394,248	-	-	-	189,457	-	-	-	1,564,696	-	20,140	599,646	136,667
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		706,487,795	525,744,199	129,373,872	1,441,291	106,434	2,407,860	756,612	305,393	-	22,327	555,918	1,012,231	196,321	770,284	8,976	55,222	38,496,250	5,234,602
	TOTAL		1,075,739,593	779,055,375	189,003,566	2,019,542	106,434	27,682,741	6,223,643	305,393	-	1,063,662	16,289,896	1,012,231	196,321	7,923,137	116,302	157,387	39,190,283	5,393,679
RB_GUP_EPIS_D	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	DISTPRI		0.25795198	0.17061456	0.04233947	0.00053754	-	0.01848090	0.00508211	-	-	0.00079190	0.01462620	-	-	0.00519471	0.00009977	0.00007625	0.00008774	0.00002083
RB_GUP_EPIS_D	DISTSEC		0.08530191	0.06486173	0.01309188	-	-	0.00501446	-	-	-	0.00017612	-	-	-	0.00145453	-	0.00001872	0.00055743	0.00012704
RB_GUP_EPIS_D	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	CUSTOMER		0.65674611	0.48872813	0.12026505	0.00133981	0.00009894	0.00223833	0.00070334	0.00028389	-	0.00002076	0.00051678	0.00094096	0.00018250	0.00071605	0.00000834	0.00005133	0.03578584	0.00486605
RB_GUP_EPIS_D	TOTAL		1.00000000	0.72420443	0.17569639	0.00187735	0.00009894	0.02573368	0.00578546	0.00028389	-	0.00098877	0.01514297	0.00094096	0.00018250	0.00736529	0.00010811	0.00014631	0.03643101	0.00501393

ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Gen & Int Plant	PRODUCTION	48,572,852	24,082,836	6,022,344	76,326	3,820	2,701,911	740,531	117,841	-	116,797	2,125,501	10,356,591	1,319,641	755,667	14,205	10,989	103,270	24,583
	BULKTRAN	13,506,184	6,696,482	1,674,575	21,223	1,062	751,294	205,912	32,767	-	32,477	591,017	2,879,757	366,940	210,121	3,950	3,056	28,715	6,835
	SUBTRAN	4,281,494	2,066,087	515,475	6,547	422	228,913	62,843	12,632	-	9,701	181,743	1,129,429	-	64,207	1,232	937	1,072	254
	DISTPRI	7,693,775	5,088,816	1,262,833	16,033	-	551,218	151,581	-	-	23,620	436,247	-	-	154,939	2,976	2,274	2,617	621
	DISTSEC	2,819,821	2,144,131	432,778	-	-	165,763	-	-	-	5,822	-	-	-	48,082	-	619	18,427	4,200
	ENERGY	28,395,554	10,433,056	3,295,682	41,158	2,085	1,669,738	450,451	70,193	-	84,091	1,662,170	8,738,204	1,221,888	469,460	8,877	8,855	194,134	45,512
	CUSTOMER	56,795,239	43,957,468	10,371,167	105,618	7,526	184,550	58,876	21,491	-	1,750	42,339	71,177	13,696	59,662	712	4,153	1,756,191	138,863
	TOTAL	162,064,920	94,468,876	23,574,854	266,906	14,915	6,253,388	1,670,194	254,924	-	274,256	5,039,017	23,175,158	2,922,165	1,762,139	31,951	30,882	2,104,425	220,869
RB_GUP_EPIS_G	PRODUCTION	0.29971231	0.14859993	0.03716007	0.00047096	0.00002357	0.01667178	0.00456935	0.00072712	-	0.00072068	0.01311512	0.06390396	0.00814267	0.00466274	0.00008765	0.00006781	0.00063721	0.00015168
RB_GUP_EPIS_G	BULKTRAN	0.08333811	0.04131975	0.01033274	0.00013096	0.00000655	0.00463576	0.00127055	0.00020218	-	0.00020039	0.00364679	0.01776916	0.00226415	0.00129652	0.00002437	0.00001885	0.00017718	0.00004218
RB_GUP_EPIS_G	SUBTRAN	0.02641839	0.01274852	0.00318067	0.00004040	0.00000260	0.00141248	0.00038776	0.00007794	-	0.00005986	0.00112142	0.00696899	-	0.00039618	0.00000760	0.00000578	0.00000661	0.00000157
RB_GUP_EPIS_G	DISTPRI	0.04747342	0.03139986	0.00779214	0.00009893	-	0.00340122	0.00093531	-	-	0.00014574	0.00269180	-	-	0.00095603	0.00001836	0.00001403	0.00001615	0.00000383
RB_GUP_EPIS_G	DISTSEC	0.01739933	0.01323007	0.00267040	-	-	0.00102282	-	-	-	0.00003592	-	-	-	0.00029669	-	0.00000382	0.00011370	0.00002591
RB_GUP_EPIS_G	ENERGY	0.17521098	0.06437578	0.02033556	0.00025396	0.00001287	0.01030290	0.00277945	0.00043312	-	0.00051887	0.01025620	0.05391792	0.00753950	0.00289674	0.00005477	0.00005464	0.00119788	0.00028083
RB_GUP_EPIS_G	CUSTOMER	0.35044746	0.27123370	0.06399391	0.00065170	0.00004644	0.00113874	0.00036328	0.00013261	-	0.00001080	0.00026125	0.00043919	0.00008451	0.00036814	0.00000439	0.00002562	0.01083634	0.00085684
RB_GUP_EPIS_G	TOTAL	1.00000000	0.58290761	0.14546549	0.00164691	0.00009203	0.03858570	0.01030571	0.00157298	-	0.00169226	0.03109258	0.14299923	0.01803083	0.01087304	0.00019715	0.00019056	0.01298508	0.00136284
Production Land	Allocate on PROD_DEMAND	4,790,602	Source: JCOS, Sch 4, KY PSC Juris.																
Prod. GUP less Land	PRODUCTION	881,210,064	436,911,502	109,257,529	1,384,712	69,303	49,018,143	13,434,738	2,137,881	-	2,118,929	38,560,892	187,889,560	23,940,971	13,709,329	257,702	199,368	1,873,525	445,979
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	881,210,064	436,911,502	109,257,529	1,384,712	69,303	49,018,143	13,434,738	2,137,881	-	2,118,929	38,560,892	187,889,560	23,940,971	13,709,329	257,702	199,368	1,873,525	445,979
RB_GUP-Land_P	PRODUCTION	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
RB_GUP-Land_P	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_P	TOTAL	1.00000000	0.49580857	0.12398579	0.00157138	0.00007865	0.05562595	0.01524578	0.00242607	-	0.00240457	0.04375902	0.21321767	0.02716829	0.01555739	0.00029244	0.00022624	0.00212608	0.00050610
Transmission Land	Allocate on BULK_TRANS	37,898,165	Source: JCOS, Sch 4, KY PSC Juris.																
Trans. GUP less Land	PRODUCTION	12,793,807	6,343,279	1,586,250	20,104	1,006	711,668	195,052	31,039	-	30,764	559,844	2,727,866	347,586	199,038	3,741	2,895	27,201	6,475
	BULKTRAN	555,815,871	275,578,273	68,913,272	873,396	43,713	30,917,783	8,473,848	1,348,450	-	1,336,497	24,321,960	118,509,767	15,100,567	8,647,045	162,544	125,750	1,181,710	281,298
	SUBTRAN	188,092,194	90,766,188	22,645,567	287,612	18,542	10,056,495	2,760,768	554,935	-	426,164	7,984,239	49,617,445	-	2,820,712	54,106	41,154	47,086	11,179
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	756,701,872	372,687,740	93,145,089	1,181,112	63,261	41,685,946	11,429,668	1,934,424	-	1,793,424	32,866,043	170,855,078	15,448,153	11,666,795	220,391	169,798	1,255,997	298,952
RB_GUP-Land_T	PRODUCTION	0.01690733	0.00838280	0.00209627	0.00002657	0.00000133	0.00094049	0.00025777	0.00004102	-	0.00004065	0.00073985	0.00360494	0.00045934	0.00026303	0.00000494	0.00000383	0.00003595	0.00000856
RB_GUP-Land_T	BULKTRAN	0.73452425	0.36418342	0.09107057	0.00115421	0.00005777	0.04085861	0.01119840	0.00178201	-	0.00176621	0.03214206	0.15661355	0.01995577	0.01142728	0.00021481	0.00016618	0.00156166	0.00037174
RB_GUP-Land_T	SUBTRAN	0.24856843	0.11994973	0.02992667	0.00038009	0.00002450	0.01328990	0.00364842	0.00073336	-	0.00056319	0.01055137	0.06557066	-	0.00372764	0.00007150	0.00005439	0.00006223	0.00001477
RB_GUP-Land_T	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_T	TOTAL	1.00000000	0.49251595	0.12309351	0.00156087	0.00008360	0.05508900	0.01510459	0.00255639	-	0.00237005	0.04343328	0.22578916	0.02041511	0.01541796	0.00029125	0.00022439	0.00165983	0.00039507
Distribution Land	Allocate on DIST_CPD	9,256,806	Source: JCOS, Sch 4, KY PSC Juris.																
Dist. GUP less Land	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	268,232,352	177,414,207	44,026,858	558,961	-	19,217,432	5,284,655	-	-	823,460	15,209,106	-	-	5,401,741	103,745	79,288	91,239	21,662
	DISTSEC	91,762,640	69,774,333	14,083,452	-	-	5,394,248	-	-	-	189,457	-	-	-	1,564,696	-	20,140	599,646	136,667
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	706,487,795	525,744,199	129,373,872	1,441,291	106,434	2,407,860	756,612	305,393	-	22,327	555,918	1,012,231	196,321	770,284	8,976	55,222	38,496,250	5,234,602
	TOTAL	1,066,482,787	772,932,739	187,484,182	2,000,252	106,434	27,019,540	6,041,268	305,393	-	1,035,244	15,765,024	1,012,231	196,321	7,736,721	112,722	154,651	39,187,134	5,392,931
RB_GUP-Land_D	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	DISTPRI	0.25151119	0.16635450	0.04128230	0.00052412	-	0.01801945	0.00495522	-	-	0.00077213	0.01426099	-	-	0.00506500	0.00009728	0.00007435	0.00008555	0.00002031
RB_GUP-Land_D	DISTSEC	0.08604231	0.06542472	0.01320551	-	-	0.00505798	-	-	-	0.00017765	-	-	-	0.00146716	-	0.00001888	0.00056226	0.00012815
RB_GUP-Land_D	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D	CUSTOMER	0.66244650	0.49297017	0.12130892	0.00135144	0.00009980	0.00225776	0.00070945	0.00028636	-	0.00002094	0.00052126	0.00094913	0.00018408	0.00072227	0.00000842	0.00005178	0.03609646	0.00490829
RB_GUP-Land_D	TOTAL	1.00000000	0.72474938	0.17579673	0.00187556	0.00009980	0.02533519	0.00566466	0.00028636	-	0.00097071	0.01478226	0.00094913	0.00018408	0.00725443	0.00010570	0.00014501	0.03674427	0.00505674
General Land	Allocate on LABOR_M	1,705,187	Source: JCOS, Sch 4, KY PSC Juris.																
Gen. GUP less Land	PRODUCTION	48,061,787	23,829,446	5,958,979	75,523	3,780	2,673,482	732,740	116,601	-	115,568	2,103,137	10,247,622	1,305,757	747,716	14,055	10,874	102,183	24,324
	BULKTRAN	13,364,077	6,626,024	1,656,956	21,000	1,051	743,389	203,746	32,422	-	32,135	584,799	2,849,457	363,079	207,910	3,908	3,024	28,413	6,764
	SUBTRAN	4,236,446	2,044,349	510,052	6,478	418	226,505	62,181	12,499	-	9,599	179,831	1,117,546	-	63,532	1,219	927	1,061	252
	DISTPRI	7,612,824	5,035,273	1,249,546	15,864	-	545,419	149,986	-	-	23,371	431,657	-	-	153,309	2,944	2,250	2,589	615
	DISTSEC	2,790,151	2,121,571	428,224	-	-	164,018	-	-	-	5,761	-	-	-	47,576	-	612	18,233	4,156
	ENERGY	28,096,787	10,323,283	3,261,006	40,725	2,063	1,652,170	445,712	69,455	-	83,206	1,644,681	8,646,264	1,209,032	464,520	8,784	8,762	192,091	45,034
	CUSTOMER	56,197,661	43,494,963	10,262,046	104,507	7,447	182,609	58,256	21,265	-	1,732	41,893	70,428	13,552	59,035	704	4,109	1,737,713	137,402
	TOTAL	160,359,733	93,474,909	23,326,808	264,098	14,758	6,187,592	1,652,621	252,242	-	271,371	4,985,998	22,931,318	2,891,419	1,743,598	31,614	30,557	2,082,283	218,545
RB_GUP-Land_G	PRODUCTION	0.29971231	0.14859993	0.03716007	0.00047096	0.00002357	0.01667178	0.00456935	0.00072712	-	0.00072068	0.01311512	0.06390396	0.00814267	0.00466274	0.00008765	0.00006781	0.00063721	0.00015168
RB_GUP-Land_G	BULKTRAN	0.08333811	0.04131975	0.01033274	0.00013096	0.00000655	0.00463576	0.00127055	0.00020218	-	0.00020039	0.00364679	0.01776916	0.00226415	0.00129652	0.00002437	0.00001885	0.00017718	0.00004218
RB_GUP-Land_G	SUBTRAN	0.02641839	0.01274852	0.00318067	0.00004040	0.00000260	0.00141248	0.00038776	0.00007794	-	0.00005986	0.00112142	0.00696899	-	0.00039618	0.00000760	0.00000578	0.00000661	0.00000157
RB_GUP-Land_G	DISTPRI	0.04747342	0.03139986	0.00779214	0.00009893	-	0.00340122	0.00093531	-	-	0.00014574	0.00269180	-	-	0.00095603	0.00001836	0.00001403	0.00001615	0.00000383
RB_GUP-Land_G	DISTSEC	0.01739933	0.01323007	0.00267040	-	-	0.00102282	-	-	-	0.00003592	-	-	-	0.00029669	-	0.00000382	0.00011370	0.00002591
RB_GUP-Land_G	ENERGY	0.17521098	0.06437578	0.02033556	0.00025396	0.00001287	0.01030290	0.00277945	0.00043312	-	0.00051887	0.01025620	0.05391792	0.00753950	0.00289674	0.00005477	0.00005464	0.00119788	0.00028083
RB_GUP-Land_G	CUSTOMER	0.35044746	0.27123370	0.06399391	0.00065170	0.00004644	0.00113874	0.00036328	0.00013261	-	0.00001080	0.00026125	0.00043919	0.00008451	0.00036814	0.00000439	0.00002562	0.01083634	0.00085684
RB_GUP-Land_G	TOTAL	1.00000000	0.58290761	0.14546549	0.00164691	0.00009203	0.03858570	0.01030571	0.00157298	-	0.00169226	0.03109258	0.14299923	0.01803083	0.01087304	0.00019715	0.00019056	0.01298508	0.00136284

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
CWIP	PRODUCTION		9,852,029	4,884,721	1,221,512	15,481	775	548,028	150,202	23,902	-	23,690	431,115	2,100,627	267,663	153,272	2,881	2,229	20,946	4,986
	BULKTRAN		51,944,651	25,754,603	6,440,399	81,625	4,085	2,889,470	791,937	126,022	-	124,904	2,273,047	11,075,518	1,411,247	808,123	15,191	11,752	110,439	26,289
	SUBTRAN		16,456,484	7,941,278	1,981,297	25,164	1,622	879,859	241,544	48,552	-	37,286	698,554	4,341,109	-	246,789	4,734	3,601	4,120	978
	DISTPRI		11,295,824	7,471,282	1,854,063	23,539	-	809,286	222,548	-	-	34,678	640,487	-	-	227,479	4,369	3,339	3,842	912
	DISTSEC		3,746,324	2,848,624	574,974	-	-	220,227	-	-	-	7,735	-	-	-	63,881	-	822	24,481	5,580
	ENERGY		1,125,028	413,356	130,574	1,631	83	66,155	17,847	2,781	-	3,332	65,855	346,206	48,411	18,600	352	351	7,692	1,803
	CUSTOMER		30,233,314	22,565,657	5,535,241	61,272	4,514	102,684	32,301	12,948	-	954	23,697	42,913	8,319	32,874	384	2,352	1,594,368	212,838
	TOTAL		124,653,655	71,879,521	17,738,060	208,711	11,079	5,515,709	1,456,379	214,204	-	232,578	4,132,755	17,906,373	1,735,640	1,551,017	27,910	24,446	1,765,888	253,386
RB_GUP_CWIP	PRODUCTION		0.07903522	0.03918634	0.00979924	0.00012419	0.00000622	0.00439641	0.00120495	0.00019175	-	0.00019005	0.00345850	0.01685171	0.00214725	0.00122958	0.00002311	0.00001788	0.00016804	0.00004000
RB_GUP_CWIP	BULKTRAN		0.41671182	0.20660929	0.05166635	0.00065481	0.00003277	0.02317999	0.00635310	0.00101097	-	0.00100201	0.01823490	0.08885032	0.01132135	0.00648295	0.00012186	0.00009428	0.00088596	0.00021090
RB_GUP_CWIP	SUBTRAN		0.13201767	0.06370674	0.01589441	0.00020187	0.00001301	0.00705843	0.00193772	0.00038950	-	0.00029911	0.00560396	0.03482536	-	0.00197979	0.00003798	0.00002888	0.00003305	0.00000785
RB_GUP_CWIP	DISTPRI		0.09061767	0.05993633	0.01487371	0.00018884	-	0.00649228	0.00178533	-	-	0.00027819	0.00513813	-	-	0.00182488	0.00003505	0.00002679	0.00003082	0.00000732
RB_GUP_CWIP	DISTSEC		0.03005386	0.02285231	0.00461258	-	-	0.00176671	-	-	-	0.00006205	-	-	-	0.00051247	-	0.00000660	0.00019639	0.00004476
RB_GUP_CWIP	ENERGY		0.00902523	0.00331604	0.00104750	0.00001308	0.00000066	0.00053071	0.00014317	0.00002231	-	0.00002673	0.00052830	0.00277735	0.00038836	0.00014921	0.00000282	0.00000281	0.00006170	0.00001447
RB_GUP_CWIP	CUSTOMER		0.24253853	0.18102684	0.04440496	0.00049154	0.00003621	0.00082376	0.00025913	0.00010387	-	0.00000765	0.00019010	0.00034426	0.00006673	0.00026372	0.00000308	0.00001887	0.01279038	0.00170743
RB_GUP_CWIP	TOTAL		1.00000000	0.57663388	0.14229875	0.00167433	0.00008888	0.04424828	0.01168340	0.00171839	-	0.00186579	0.03315390	0.14364900	0.01392370	0.01244261	0.00022390	0.00019611	0.01416635	0.00203272
T&D Plant	PRODUCTION		12,793,807	6,343,279	1,586,250	20,104	1,006	711,668	195,052	31,039	-	30,764	559,844	2,727,866	347,586	199,038	3,741	2,895	27,201	6,475
	BULKTRAN		593,714,036	294,368,508	73,612,106	932,948	46,693	33,025,904	9,051,636	1,440,394	-	1,427,625	25,980,346	126,590,326	16,130,195	9,236,641	173,627	134,324	1,262,285	300,478
	SUBTRAN		188,092,194	90,766,188	22,645,567	287,612	18,542	10,056,495	2,760,768	554,935	-	426,164	7,984,239	49,617,445	-	2,820,712	54,106	41,154	47,086	11,179
	DISTPRI		277,489,158	183,536,843	45,546,242	578,251	-	19,880,633	5,467,031	-	-	851,878	15,733,978	-	-	5,588,157	107,326	82,024	94,387	22,410
	DISTSEC		91,762,640	69,774,333	14,083,452	-	-	5,394,248	-	-	-	189,457	-	-	-	1,564,696	-	20,140	599,646	136,667
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		706,487,795	525,744,199	129,373,872	1,441,291	106,434	2,407,860	756,612	305,393	-	22,327	555,918	1,012,231	196,321	770,284	8,976	55,222	38,496,250	5,234,602
	TOTAL		1,870,339,630	1,170,533,350	286,847,490	3,260,206	172,675	71,476,809	18,231,099	2,331,761	-	2,948,215	50,814,326	179,947,867	16,674,102	20,179,529	347,777	335,759	40,526,855	5,711,811
TDPLANT	PRODUCTION		0.00684037	0.00339151	0.00084811	0.00001075	0.00000054	0.00038050	0.00010429	0.00001660	-	0.00001645	0.00029933	0.00145849	0.00018584	0.00010642	0.00000200	0.00000155	0.00001454	0.00000346
TDPLANT	BULKTRAN		0.31743648	0.15738773	0.03935761	0.00049881	0.00002497	0.01765770	0.00483957	0.00077012	-	0.00076330	0.01389071	0.06768307	0.00862421	0.00493848	0.00009283	0.00007182	0.00067490	0.00016065
TDPLANT	SUBTRAN		0.10056580	0.04852925	0.01210773	0.00015378	0.00000991	0.00537683	0.00147608	0.00029670	-	0.00022785	0.00426887	0.02652857	-	0.00150813	0.00002893	0.00002200	0.00002518	0.00000598
TDPLANT	DISTPRI		0.14836298	0.09813022	0.02435186	0.00030917	-	0.01062942	0.00292302	-	-	0.00045547	0.00841236	-	-	0.00298778	0.00005738	0.00004386	0.00005047	0.00001198
TDPLANT	DISTSEC		0.04906202	0.03730570	0.00752989	-	-	0.00288410	-	-	-	0.00010130	-	-	-	0.00083658	-	0.00001077	0.00032061	0.00007307
TDPLANT	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDPLANT	CUSTOMER		0.37773236	0.28109558	0.06917133	0.00077060	0.00005691	0.00128739	0.00040453	0.00016328	-	0.00001194	0.00029723	0.00054120	0.00010497	0.00041184	0.00000480	0.00002953	0.02058249	0.00279874
TDPLANT	TOTAL		1.00000000	0.62584000	0.15336653	0.00174311	0.00009232	0.03821595	0.00974748	0.00124670	-	0.00157630	0.02716850	0.09621133	0.00891501	0.01078923	0.00018594	0.00017952	0.02166818	0.00305389
Electric Plant in Service	PRODUCTION		947,367,325	469,712,839	117,460,090	1,488,670	74,506	52,698,203	14,443,357	2,298,383	-	2,278,009	41,455,869	201,995,457	25,738,350	14,738,564	277,049	214,336	2,014,181	479,462
	BULKTRAN		607,220,221	301,064,990	75,286,681	954,171	47,755	33,777,199	9,257,548	1,473,161	-	1,460,102	26,571,364	129,470,083	16,497,135	9,446,762	177,576	137,380	1,291,000	307,313
	SUBTRAN		192,373,688	92,832,276	23,161,042	294,159	18,964	10,285,409	2,823,611	567,567	-	435,864	8,165,982	50,746,874	-	2,884,920	55,338	42,091	48,158	11,434
	DISTPRI		285,182,934	188,625,658	46,809,075	594,283	-	20,431,851	5,618,612	-	-	875,497	16,170,224	-	-	5,743,096	110,302	84,298	97,004	23,031
	DISTSEC		94,582,460	71,918,463	14,516,230	-	-	5,560,011	-	-	-	195,279	-	-	-	1,612,778	-	20,759	618,073	140,867
	ENERGY		28,395,554	10,433,056	3,295,682	41,158	2,085	1,669,738	450,451	70,193	-	84,091	1,662,170	8,738,204	1,221,888	469,460	8,877	8,855	194,134	45,512
	CUSTOMER		763,283,034	569,701,667	139,745,039	1,546,910	113,960	2,592,410	815,488	326,884	-	24,077	598,257	1,083,408	210,017	829,947	9,688	59,375	40,252,441	5,373,465
	TOTAL		2,918,405,216	1,704,288,949	420,273,839	4,919,352	257,271	127,014,821	33,409,067	4,736,188	-	5,352,919	94,623,867	392,034,026	43,667,391	35,725,527	638,831	567,094	44,514,991	6,381,084
RB_GUP_EPIS	PRODUCTION		0.32461816	0.16094846	0.04024804	0.00051010	0.00002553	0.01805719	0.00494906	0.00078755	-	0.00078057	0.01420497	0.06921433	0.00881932	0.00505021	0.00009493	0.00007344	0.00069016	0.00016429
RB_GUP_EPIS	BULKTRAN		0.20806577	0.10316079	0.02579720	0.00032695	0.00001636	0.01157385	0.00317213	0.00050478	-	0.00050031	0.00910475	0.04436330	0.00565279	0.00323696	0.00006085	0.00004707	0.00044236	0.00010530
RB_GUP_EPIS	SUBTRAN		0.06591740	0.03180925	0.00793620	0.00010079	0.00000650	0.00352433	0.00096752	0.00019448	-	0.00014935	0.00279810	0.01738856	-	0.00098853	0.00001896	0.00001442	0.00001650	0.00000392
RB_GUP_EPIS	DISTPRI		0.09771876	0.06463313	0.01603927	0.00020363	-	0.00700103	0.00192523	-	-	0.00029999	0.00554077	-	-	0.00196789	0.00003780	0.00002889	0.00003324	0.00000789
RB_GUP_EPIS	DISTSEC		0.03240895	0.02464307	0.00497403	-	-	0.00190515	-	-	-	0.00006691	-	-	-	0.00055262	-	0.00000711	0.00021178	0.00004827
RB_GUP_EPIS	ENERGY		0.00972982	0.00357492	0.00112927	0.00001410	0.00000071	0.00057214	0.00015435	0.00002405	-	0.00002881	0.00056955	0.00299417	0.00041868	0.00016086	0.00000304	0.00000303	0.00006652	0.00001559
RB_GUP_EPIS	CUSTOMER		0.26154114	0.19520993	0.04788404	0.00053005	0.00003905	0.00088830	0.00027943	0.00011201	-	0.00000825	0.00020499	0.00037123	0.00007196	0.00028438	0.00000332	0.00002035	0.01379262	0.00184123
RB_GUP_EPIS	TOTAL		1.00000000	0.58397954	0.14400805	0.00168563	0.00008815	0.04352200	0.01144771	0.00162287	-	0.00183419	0.03242314	0.13433159	0.01496276	0.01224146	0.00021890	0.00019432	0.01525319	0.00218650
Gross Utility Plant	PRODUCTION	Same as	947,367,325	469,712,839	117,460,090	1,488,670	74,506	52,698,203	14,443,357	2,298,383	-	2,278,009	41,455,869	201,995,457	25,738,350	14,738,564	277,049	214,336	2,014,181	479,462
	BULKTRAN	RB_GUP_EPIS	607,220,221	301,064,990	75,286,681	954,171	47,755	33,777,199	9,257,548	1,473,161	-	1,460,102	26,571,364	129,470,083	16,497,135	9,446,762	177,576	137,380	1,291,000	307,313
	SUBTRAN		192,373,688	92,832,276	23,161,042	294,159	18,964	10,285,409	2,823,611	567,567	-	435,864	8,165,982	50,746,874	-	2,884,920	55,338	42,091	48,158	11,434
	DISTPRI		285,182,934	188,625,658	46,809,075	594,283	-	20,431,851	5,618,612	-	-	875,497	16,170,224	-	-	5,743,096	110,302	84,298	97,004	23,031
	DISTSEC		94,582,460	71,918,463	14,516,230	-	-	5,560,011	-	-	-	195,279	-	-	-	1,612,778	-	20,759	618,073	140,867
	ENERGY		28,395,554	10,433,056	3,295,682	41,158	2,085	1,669,738	450,451	70,193	-	84,091	1,662,170	8,738,204	1,221,888	469,460	8,877	8,855	194,134	45,512
	CUSTOMER		763,283,034	569,701,667	139,745,039	1,546,910	113,960	2,592,410	815,488	326,884	-	24,077	598,257	1,083,408	210,017	829,947	9,688	59,375	40,252,441	5,373,465
	TOTAL		2,918,405,216	1,704,288,949	420,273,839	4,919,352	257,271	127,014,821	33,409,067	4,736,188	-	5,352,919	94,623,867	392,034,026	43,667,391	35,725,527	638,831	567,094	44,514,991	6,381,084
RB_GUP	PRODUCTION		0.32461816	0.16094846	0.04024804	0.00051010	0.00002553	0.01805719	0.00494906	0.00078755	-	0.00078057	0.01420497	0.06921433	0.00881932	0.00505021	0.00009493	0.00007344	0.00069016	0.00016429
RB_GUP	BULKTRAN		0.20806577	0.10316079	0.02579720	0.00032695	0.00001636	0.01157385	0.00317213	0.00050478	-	0.00050031	0.00910475	0.04436330	0.00565279	0.00323696	0.00006085	0.00004707	0.00044236	0.00010530
RB_GUP	SUBTRAN		0.06591740	0.03180925	0.00793620	0.00010079	0.00000650	0.00352433	0.00096752	0.00019448	-	0.00014935	0.00279810	0.01738856	-	0.00098853	0.00001896	0.00001442	0.00001650	0.00000392
RB_GUP	DISTPRI		0.09771876	0.06463313	0.01603927	0.00020363	-	0.00700103	0.00192523	-	-	0.00029999	0.00554077	-	-	0.00196789	0.00003780	0.00002889	0.00003324	0.00000789
RB_GUP	DISTSEC		0.03240895	0.02464307	0.00497403	-	-	0.00190515	-	-	-	0.00006691	-	-	-	0.00055262	-	0.00000711	0.00021178	0.00004827
RB_GUP	ENERGY		0.00972982	0.00357492	0.00112927	0.00001410	0.00000071	0.00057214	0.00015435	0.00002405	-	0.00002881	0.00056955	0.00299417	0.00041868	0.00016086	0.00000304	0.00000303	0.00006652	0.00001559
RB_GUP	CUSTOMER		0.26154114	0.19520993	0.04788404	0.00053005	0.00003905	0.00088830	0.00027943	0.00011201	-	0.00000825	0.00020499	0.00037123	0.00007196	0.00028438	0.00000332	0.00002035	0.01379262	0.00184123
RB_GUP	TOTAL		1.00000000	0.58397954	0.14400805	0.00168563	0.00008815	0.04352200	0.01144771	0.00162287	-	0.00183419	0.03242314	0.13433159	0.01496276	0.01224146	0.00021890	0.00019432	0.01525319	0.00218650
Net EPIS	PRODUCTION		500,414,411	248,109,754	62,044,278	786,339	39,355	27,836,025	7,629,210	1,214,042	-	1,203,280	21,897,646	106,697,197	13,595,404	7,785,143	146,342	113,216	1,063,922	253,259
	BULKTRAN		405,566,839	201,083,515	50,284,527	637,298	31,896	22,560,039	6,183,184	983,935	-	975,213	17,747,209	86,474,018	11,018,558	6,309,562	118,605	91,757	862,269	205,257
	SUBTRAN		124,652,307	60,152,495	15,007,652	190,606	12,288	6,664,632	1,829,614	367,766	-	282,427	5,291,309	32,882,433	-	1,869,340	35,857	27,273	31,205	7,409
	DISTPRI		199,774,848	132,135,054	32,790,447	416,304	-	14,312,813	3,935,920	-	-	613,299	11,327,481	-	-	4,023,124	77,268	59,052	67,953	16,134
	DISTSEC		65,304,010	49,655,762	10,022,662	-	-	3,838,883	-	-	-	134,830	-	-	-	1,113,535	-	14,333	426,745	97,261
	ENERGY		19,287,023	7,086,412	2,238,515	27,956	1,416	1,134,131	305,959	47,677	-	57,117	1,128,991	5,935,223	829,939	318,870	6,030	6,014	131,861	30,913
	CUSTOMER		526,611,546	393,035,921	96,414,551	1,067,369	78,635	1,788,677	562,650	225,560	-	16,612	412,781	747,585	144,919	572,629	6,684	40,968	27,785,676	3,710,330
	TOTAL		1,841,610,985	1,091,258,911	268,802,632	3,125,872	163,591	78,135,200	20,446,537	2,838,980	-	3,282,777	57,805,415	232,736,455	25,588,820	21,992,202	390,785	352,613	30,369,631	4,320,563
NP	PRODUCTION		0.27172645	0.13472430	0.03369022	0.00042698	0.00002137	0.01511504	0.00414268	0.00065923	-	0.00065338	0.01189048	0.05793688	0.00738234	0.00422735	0.00007946	0.00006148	0.00057771	0.00013752
NP	BULKTRAN		0.22022395	0.10918892	0.02730464	0.00034605	0.00001732	0.01225017	0.00335749	0.00053428	-	0.00052954	0.00963678	0.04695564	0.00598311	0.00342611	0.00006440	0.00004982	0.00046821	0.00011146
NP	SUBTRAN		0.06768656	0.03266298	0.00814920	0.00010350	0.00000667	0.00361891	0.00099349	0.00019970	-	0.00015336	0.00287320	0.01785525	-	0.00101506	0.00001947	0.00001481	0.00001694	0.00000402
NP	DISTPRI		0.10847831	0.07174971	0.01780531	0.00022605	-	0.00777190	0.00213722	-	-	0.00033302	0.00615085	-	-	0.00218457	0.00004196	0.00003207	0.00003690	0.00000876
NP	DISTSEC		0.03546026	0.02696322	0.00544233	-	-	0.00208452	-	-	-	0.00007321	-	-	-	0.00060465	-	0.00000778	0.00023172	0.00005281
NP	ENERGY		0.01047291	0.00384794	0.00121552	0.00001518	0.00000077	0.00061584	0.00016614	0.00002589	-	0.00003101	0.00061305	0.00322284	0.00045066	0.00017315	0.00000327	0.00000327	0.00007160	0.00001679
NP	CUSTOMER		0.28595157	0.21341962	0.05235338	0.00057958	0.00004270	0.00097126	0.00030552	0.00012248	-	0.00000902	0.00022414	0.00040594	0.00007869	0.00031094	0.00000363	0.00002225	0.01508770	0.00201472
NP	TOTAL		1.00000000	0.59255669	0.14596059	0.00169736	0.00008883	0.04242764	0.01110253	0.00154157	-	0.00178256	0.03138850	0.12637656	0.01389480	0.01194183	0.00021220	0.00019147	0.01649080	0.00234608

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Rate Base	PRODUCTION	475,209,885	234,697,558	58,866,981	674,555	16,129	26,570,221	7,060,307	1,122,240	-	1,138,745	20,205,938	102,761,814	13,011,163	7,557,174	142,278	109,998	1,028,585	246,199
	BULKTRAN	404,344,423	199,879,987	50,101,328	589,265	18,191	22,579,101	6,045,502	961,182	-	969,870	17,312,987	87,146,760	11,051,079	6,395,761	120,371	93,120	871,607	208,311
	SUBTRAN	124,315,929	59,781,336	14,951,281	175,798	6,846	6,670,432	1,787,619	359,000	-	280,832	5,157,858	33,146,090	-	1,895,663	36,408	27,691	31,553	7,522
	DISTPRI	185,857,838	122,958,064	30,585,945	359,836	-	13,411,898	3,601,493	-	-	570,987	10,341,356	-	-	3,819,046	73,439	56,120	64,320	15,334
	DISTSEC	60,788,236	46,162,527	9,340,150	-	-	3,594,162	-	-	-	125,407	-	-	-	1,056,353	-	13,613	403,645	92,379
	ENERGY	51,938,706	19,089,361	6,021,009	72,833	3,194	3,059,302	820,532	127,923	-	153,206	3,031,313	15,992,807	2,233,039	863,889	16,330	16,090	354,326	83,551
	CUSTOMER	491,032,839	366,040,686	89,998,873	922,044	40,956	1,677,352	515,118	206,275	-	15,476	377,026	705,945	136,169	544,098	6,360	38,963	26,283,980	3,523,520
	TOTAL	1,793,487,856	1,048,609,520	259,865,567	2,794,331	85,317	77,562,467	19,830,571	2,776,619	-	3,254,523	56,426,478	239,753,416	26,431,451	22,131,986	395,185	355,593	29,038,015	4,176,817
RATEBASE	PRODUCTION	0.26496409	0.13086097	0.03282263	0.00037611	0.00000899	0.01481483	0.00393663	0.00062573	-	0.00063493	0.01126628	0.05729719	0.00725467	0.00421367	0.00007933	0.00006133	0.00057351	0.00013727
RATEBASE	BULKTRAN	0.22545144	0.11144764	0.02793514	0.00032856	0.00001014	0.01258949	0.00337081	0.00053593	-	0.00054077	0.00965325	0.04859066	0.00616178	0.00356610	0.00006712	0.00005192	0.00048598	0.00011615
RATEBASE	SUBTRAN	0.06931518	0.03333245	0.00833643	0.00009802	0.00000382	0.00371925	0.00099673	0.00020017	-	0.00015658	0.00287588	0.01848136	-	0.00105697	0.00002030	0.00001544	0.00001759	0.00000419
RATEBASE	DISTPRI	0.10362927	0.06855807	0.01705389	0.00020063	-	0.00747811	0.00200809	-	-	0.00031837	0.00576606	-	-	0.00212940	0.00004095	0.00003129	0.00003586	0.00000855
RATEBASE	DISTSEC	0.03389387	0.02573897	0.00520781	-	-	0.00200401	-	-	-	0.00006992	-	-	-	0.00058899	-	0.00000759	0.00022506	0.00005151
RATEBASE	ENERGY	0.02895961	0.01064371	0.00335715	0.00004061	0.00000178	0.00170578	0.00045751	0.00007133	-	0.00008542	0.00169018	0.00891715	0.00124508	0.00048168	0.00000911	0.00000897	0.00019756	0.00004659
RATEBASE	CUSTOMER	0.27378654	0.20409432	0.05018092	0.00051411	0.00002284	0.00093525	0.00028722	0.00011501	-	0.00000863	0.00021022	0.00039362	0.00007592	0.00030337	0.00000355	0.00002172	0.01465523	0.00196462
RATEBASE	TOTAL	1.00000000	0.58467612	0.14489397	0.00155804	0.00004757	0.04324672	0.01105699	0.00154817	-	0.00181463	0.03146187	0.13367998	0.01473746	0.01234019	0.00022034	0.00019827	0.01619081	0.00232888
CUST_451	TOTAL	1.00000000	0.90345012	0.07293317	0.00011571	0.00009679	0.00050289	0.00003783	0.00005896	-	-	-	-	-	-	-	-	0.02280452	-
RB_GUP_EPIS_D	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	DISTPRI	0.25795198	0.17061456	0.04233947	0.00053754	-	0.01848090	0.00508211	-	-	0.00079190	0.01462620	-	-	0.00519471	0.00009977	0.00007625	0.00008774	0.00002083
RB_GUP_EPIS_D	DISTSEC	0.08530191	0.06486173	0.01309188	-	-	0.00501446	-	-	-	0.00017612	-	-	-	0.00145453	-	0.00001872	0.00055743	0.00012704
RB_GUP_EPIS_D	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	CUSTOMER	0.65674611	0.48872813	0.12026505	0.00133981	0.00009894	0.00223833	0.00070334	0.00028389	-	0.00002076	0.00051678	0.00094096	0.00018250	0.00071605	0.00000834	0.00005133	0.03578584	0.00486605
RB_GUP_EPIS_D	TOTAL	1.00000000	0.72420443	0.17569639	0.00187735	0.00009894	0.02573368	0.00578546	0.00028389	-	0.00098877	0.01514297	0.00094096	0.00018250	0.00736529	0.00010811	0.00014631	0.03643101	0.00501393
MISC_SERV_REV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	DISTPRI	0.23090081	0.21284287	0.01757550	0.00003313	-	0.00036115	0.00003323	-	-	-	-	-	-	-	-	-	0.00005492	-
MISC_SERV_REV	DISTSEC	0.08679695	0.08091547	0.00543456	-	-	0.00009799	-	-	-	-	-	-	-	-	-	-	0.00034893	-
MISC_SERV_REV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MISC_SERV_REV	CUSTOMER	0.68230224	0.60969178	0.04992311	0.00008258	0.00009679	0.00004374	0.00000460	0.00005896	-	-	-	-	-	-	-	-	0.02240067	-
MISC_SERV_REV	TOTAL	1.00000000	0.90345012	0.07293317	0.00011571	0.00009679	0.00050289	0.00003783	0.00005896	-	-	-	-	-	-	-	-	0.02280452	-
			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
364 Poles	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	35,464,857	23,457,161	5,821,096	73,904	-	2,540,870	698,721	-	-	108,875	2,010,901	-	-	714,202	13,717	10,483	12,063	2,864
	DISTSEC	15,888,199	12,081,044	2,438,473	-	-	933,985	-	-	-	32,803	-	-	-	270,919	-	3,487	103,825	23,663
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	243,142,868	196,083,438	45,919,479	107,149	-	559,558	105,661	-	-	5,953	62,504	-	-	205,370	1,488	11,905	-	80,362
	TOTAL	294,495,923	231,621,643	54,179,047	181,053	-	4,034,412	804,382	-	-	147,632	2,073,405	-	-	1,190,490	15,205	25,876	115,889	106,889
365 Overhead Lines	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	37,833,947	25,024,124	6,209,951	78,841	-	2,710,603	745,396	-	-	116,148	2,145,232	-	-	761,911	14,633	11,183	12,869	3,055
	DISTSEC	16,949,548	12,888,071	2,601,365	-	-	996,376	-	-	-	34,995	-	-	-	289,016	-	3,720	110,761	25,244
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	259,385,071	209,182,021	48,986,949	114,307	-	596,937	112,720	-	-	6,350	66,679	-	-	219,089	1,588	12,701	-	85,730
	TOTAL	314,168,566	247,094,216	57,798,266	193,148	-	4,303,915	858,116	-	-	157,494	2,211,911	-	-	1,270,016	16,221	27,604	123,630	114,030
TOTOHLINES	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	DISTPRI	0.12042563	0.07965190	0.01976630	0.00025095	-	0.00862786	0.00237260	-	-	0.00036970	0.00682828	-	-	0.00242517	0.00004658	0.00003560	0.00004096	0.00000973
TOTOHLINES	DISTSEC	0.05395049	0.04102279	0.00828016	-	-	0.00317147	-	-	-	0.00011139	-	-	-	0.00091994	-	0.00001184	0.00035255	0.00008035
TOTOHLINES	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES	CUSTOMER	0.82562388	0.66582734	0.15592569	0.00036384	-	0.00190005	0.00035879	-	-	0.00002021	0.00021224	-	-	0.00069736	0.00000505	0.00004043	-	0.00027288
TOTOHLINES	TOTAL	1.00000000	0.78650203	0.18397215	0.00061479	-	0.01369938	0.00273139	-	-	0.00050130	0.00704052	-	-	0.00404247	0.00005163	0.00008786	0.00039352	0.00036296
366 Underground Conduit	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	2,694,549	1,782,228	442,275	5,615	-	193,050	53,087	-	-	8,272	152,784	-	-	54,264	1,042	796	917	218
	DISTSEC	345,267	262,534	52,991	-	-	20,296	-	-	-	713	-	-	-	5,887	-	76	2,256	514
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	6,419,314	5,176,879	1,212,339	2,829	-	14,773	2,790	-	-	157	1,650	-	-	5,422	39	314	-	2,122
	TOTAL	9,459,130	7,221,641	1,707,605	8,444	-	228,120	55,877	-	-	9,142	154,434	-	-	65,573	1,081	1,187	3,173	2,854
367 Underground Lines	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	3,654,692	2,417,286	599,870	7,616	-	261,839	72,004	-	-	11,220	207,226	-	-	73,599	1,414	1,080	1,243	295
	DISTSEC	468,295	356,082	71,873	-	-	27,529	-	-	-	967	-	-	-	7,985	-	103	3,060	697
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	8,706,697	7,021,547	1,644,329	3,837	-	20,037	3,784	-	-	213	2,238	-	-	7,354	53	426	-	2,878
	TOTAL	12,829,684	9,794,915	2,316,072	11,453	-	309,405	75,788	-	-	12,400	209,464	-	-	88,938	1,467	1,609	4,303	3,870
TOTUGLINES	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	DISTPRI	0.28486221	0.18841353	0.04675643	0.00059362	-	0.02040887	0.00561229	-	-	0.00087451	0.01615204	-	-	0.00573664	0.00011018	0.00008420	0.00009690	0.00002301
TOTUGLINES	DISTSEC	0.03650092	0.02775451	0.00560205	-	-	0.00214570	-	-	-	0.00007536	-	-	-	0.00062240	-	0.00000801	0.00023852	0.00005436
TOTUGLINES	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES	CUSTOMER	0.67863687	0.54728914	0.12816601	0.00029907	-	0.00156178	0.00029491	-	-	0.00001661	0.00017445	-	-	0.00057321	0.00000415	0.00003323	-	0.00022430
TOTUGLINES	TOTAL	1.00000000	0.76345718	0.18052450	0.00089268	-	0.02411636	0.00590720	-	-	0.00096649	0.01632649	-	-	0.00693224	0.00011433	0.00012544	0.00033542	0.00030167

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
		Excl. 580 -																		
Acct 581-589	PRODUCTION	Acct. 580 allocated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	on this: TOTOXEXP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		1,696,533	1,122,120	278,464	3,535	-	121,548	33,425	-	-	5,208	96,195	-	-	34,165	656	501	577	137
	DISTSEC		414,024	314,815	63,543	-	-	24,338	-	-	-	855	-	-	-	7,060	-	91	2,706	617
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		4,845,662	3,212,153	1,068,639	62,597	5,385	55,087	28,097	15,452	-	420	22,103	51,217	9,933	14,478	311	1,374	215,201	83,215
	TOTAL		6,956,219	4,649,088	1,410,646	66,132	5,385	200,973	61,522	15,452	-	6,483	118,298	51,217	9,933	55,703	967	1,966	218,484	83,969
TOTOXEXP	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	DISTPRI		0.24388717	0.16131182	0.04003091	0.00050823	-	0.01747323	0.00480501	-	-	0.00074872	0.01382870	-	-	0.00491147	0.00009433	0.00007209	0.00008296	0.00001970
TOTOXEXP	DISTSEC		0.05951858	0.04525664	0.00913473	-	-	0.00349879	-	-	-	0.00012288	-	-	-	0.00101488	-	0.00001306	0.00038894	0.00008864
TOTOXEXP	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP	CUSTOMER		0.69659426	0.46176706	0.15362358	0.00899871	0.00077418	0.00791912	0.00403912	0.00222136	-	0.00006033	0.00317742	0.00736276	0.00142800	0.00208126	0.00004467	0.00019752	0.03093650	0.01196266
TOTOXEXP	TOTAL		1.00000000	0.66833552	0.20278922	0.00950694	0.00077418	0.02889114	0.00884413	0.00222136	-	0.00093193	0.01700612	0.00736276	0.00142800	0.00800762	0.00013900	0.00028268	0.03140840	0.01207100
		Excl. 590 -																		
Acct 591-598	PRODUCTION	Acct. 590 allocated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	on this: TOTMXEXP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		4,407,910	2,915,479	723,501	9,186	-	315,803	86,844	-	-	13,532	249,934	-	-	88,768	1,705	1,303	1,499	356
	DISTSEC		1,832,190	1,393,157	281,199	-	-	107,705	-	-	-	3,783	-	-	-	31,242	-	402	11,973	2,729
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		27,949,020	22,500,944	5,276,932	13,754	129	65,311	12,757	370	-	691	7,678	1,228	238	23,833	178	1,394	23,102	20,480
	TOTAL		34,189,119	26,809,580	6,281,632	22,940	129	488,820	99,600	370	-	18,006	257,612	1,228	238	143,842	1,883	3,100	36,574	23,565
TOTMXEXP	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	DISTPRI		0.12892727	0.08527506	0.02116174	0.00026867	-	0.00923696	0.00254010	-	-	0.00039580	0.00731034	-	-	0.00259637	0.00004987	0.00003811	0.00004385	0.00001041
TOTMXEXP	DISTSEC		0.05358984	0.04074856	0.00822481	-	-	0.00315027	-	-	-	0.00011064	-	-	-	0.00091379	-	0.00001176	0.00035020	0.00007981
TOTMXEXP	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMXEXP	CUSTOMER		0.81748288	0.65813172	0.15434538	0.00040229	0.00000378	0.00191029	0.00037312	0.00001084	-	0.00002021	0.00022457	0.00003591	0.00000697	0.00069709	0.00000520	0.00004079	0.00067571	0.00059902
TOTMXEXP	TOTAL		1.00000000	0.78415535	0.18373192	0.00067096	0.00000378	0.01429752	0.00291322	0.00001084	-	0.00052665	0.00753490	0.00003591	0.00000697	0.00420726	0.00005506	0.00009066	0.00106976	0.00068925
Acct 561-574	PRODUCTION		0	0	(0)	0	0	(0)	0	(0)	-	(0)	0	0	(0)	0	0	(0)	0	(0)
	BULKTRAN		1,004,450	498,015	124,538	1,578	79	55,873	15,314	2,437	-	2,415	43,954	214,166	27,289	15,627	294	227	2,136	508
	SUBTRAN		318,413	153,654	38,336	487	31	17,024	4,674	939	-	721	13,516	83,995	-	4,775	92	70	80	19
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		1,322,863	651,669	162,873	2,065	110	72,898	19,987	3,376	-	3,137	57,470	298,162	27,289	20,402	385	297	2,215	527
EXP_OM_TRAN	PRODUCTION		0.00000000	0.00000000	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	(0.00000000)	-	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	(0.00000000)
EXP_OM_TRAN	BULKTRAN		0.75930000	0.37646745	0.09414241	0.00119315	0.00005972	0.04223678	0.01157612	0.00184212	-	0.00182579	0.03322623	0.16189618	0.02062888	0.01181273	0.00022205	0.00017179	0.00161433	0.00038428
EXP_OM_TRAN	SUBTRAN		0.24070000	0.11615273	0.02897934	0.00036805	0.00002373	0.01286921	0.00353293	0.00071015	-	0.00054536	0.01021736	0.06349503	-	0.00360964	0.00006924	0.00005266	0.00006026	0.00001431
EXP_OM_TRAN	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN	TOTAL		1.00000000	0.49262018	0.12312176	0.00156120	0.00008344	0.05510599	0.01510906	0.00255226	-	0.00237115	0.04344359	0.22539121	0.02062888	0.01542237	0.00029129	0.00022445	0.00167459	0.00039859
Acct 580-598	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		6,509,391	4,305,441	1,068,432	13,565	-	466,364	128,247	-	-	19,984	369,091	-	-	131,088	2,518	1,924	2,214	526
	DISTSEC		2,385,736	1,814,062	366,156	-	-	140,245	-	-	-	4,926	-	-	-	40,681	-	524	15,590	3,553
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		34,749,518	27,205,412	6,733,328	84,528	6,166	130,213	44,848	17,692	-	1,195	32,806	58,641	11,373	41,218	534	3,002	264,344	114,217
	TOTAL		43,644,645	33,324,915	8,167,916	98,092	6,166	736,821	173,095	17,692	-	26,104	401,897	58,641	11,373	212,987	3,052	5,449	282,148	118,296
EXP_OM_DIST	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	DISTPRI		0.14914525	0.09864763	0.02448026	0.00031080	-	0.01068547	0.00293843	-	-	0.00045787	0.00845672	-	-	0.00300353	0.00005769	0.00004409	0.00005073	0.00001204
EXP_OM_DIST	DISTSEC		0.05466274	0.04156437	0.00838947	-	-	0.00321334	-	-	-	0.00011286	-	-	-	0.00093208	-	0.00001200	0.00035721	0.00008141
EXP_OM_DIST	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST	CUSTOMER		0.79619202	0.62333905	0.15427616	0.00193672	0.00014128	0.00298348	0.00102757	0.00040537	-	0.00002737	0.00075167	0.00134361	0.00026059	0.00094441	0.00001224	0.00006878	0.00605673	0.00261698
EXP_OM_DIST	TOTAL		1.00000000	0.76355105	0.18714588	0.00224752	0.00014128	0.01688228	0.00396600	0.00040537	-	0.00059810	0.00920839	0.00134361	0.00026059	0.00488002	0.00006993	0.00012486	0.00646467	0.00271044
Acct 560-598	PRODUCTION		0	0	(0)	0	0	(0)	0	(0)	-	(0)	0	0	(0)	0	0	(0)	0	(0)
	BULKTRAN		1,004,450	498,015	124,538	1,578	79	55,873	15,314	2,437	-	2,415	43,954	214,166	27,289	15,627	294	227	2,136	508
	SUBTRAN		318,413	153,654	38,336	487	31	17,024	4,674	939	-	721	13,516	83,995	-	4,775	92	70	80	19
	DISTPRI		6,509,391	4,305,441	1,068,432	13,565	-	466,364	128,247	-	-	19,984	369,091	-	-	131,088	2,518	1,924	2,214	526
	DISTSEC		2,385,736	1,814,062	366,156	-	-	140,245	-	-	-	4,926	-	-	-	40,681	-	524	15,590	3,553
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		34,749,518	27,205,412	6,733,328	84,528	6,166	130,213	44,848	17,692	-	1,195	32,806	58,641	11,373	41,218	534	3,002	264,344	114,217
	TOTAL		44,967,508	33,976,584	8,330,789	100,158	6,276	809,719	193,082	21,069	-	29,241	459,367	356,803	38,663	233,388	3,437	5,746	284,363	118,823
TDOMX	PRODUCTION		0.00000000	0.00000000	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	(0.00000000)	-	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	0.00000000	(0.00000000)	0.00000000	(0.00000000)
TDOMX	BULKTRAN		0.02233724	0.01107499	0.00276950	0.00003510	0.00000176	0.00124253	0.00034055	0.00005419	-	0.00005371	0.00097746	0.00476269	0.00060686	0.00034751	0.00000653	0.00000505	0.00004749	0.00001130
TDOMX	SUBTRAN		0.00708096	0.00341700	0.00085252	0.00001083	0.00000070	0.00037859	0.00010393	0.00002089	-	0.00001604	0.00030058	0.00186791	-	0.00010619	0.00000204	0.00000155	0.00000177	0.00000042
TDOMX	DISTPRI		0.14475766	0.09574559	0.02376009	0.00030166	-	0.01037112	0.00285198	-	-	0.00044440	0.00820794	-	-	0.00291517	0.00005599	0.00004279	0.00004924	0.00001169
TDOMX	DISTSEC		0.05305466	0.04034162	0.00814267	-	-	0.00311881	-	-	-	0.00010954	-	-	-	0.00090466	-	0.00001164	0.00034670	0.00007902
TDOMX	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDOMX	CUSTOMER		0.77276948	0.60500154	0.14973763	0.00187975	0.00013712	0.00289571	0.00099734	0.00039345	-	0.00002657	0.00072956	0.00130408	0.00025293	0.00091662	0.00001188	0.00006675	0.00587855	0.00253999
TDOMX	TOTAL		1.00000000	0.75558075	0.18526241	0.00222733	0.00013958	0.01800676	0.00429381	0.00046853	-	0.00065026	0.01021553	0.00793469	0.00085979	0.00519016	0.00007644	0.00012779	0.00632375	0.00264243

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Acct 902-904	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	8,371,576	6,364,524	1,291,186	3,059	127	16,440	3,150	311	-	182	1,916	1,003	136	5,862	43	323	681,256	2,056
	TOTAL	8,371,576	6,364,524	1,291,186	3,059	127	16,440	3,150	311	-	182	1,916	1,003	136	5,862	43	323	681,256	2,056
TOTOX234	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	CUSTOMER	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563
TOTOX234	TOTAL	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563
Acct 901-905	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	8,412,187	6,395,399	1,297,450	3,074	128	16,520	3,166	313	-	182	1,925	1,008	137	5,890	43	325	684,561	2,066
	TOTAL	8,412,187	6,395,399	1,297,450	3,074	128	16,520	3,166	313	-	182	1,925	1,008	137	5,890	43	325	684,561	2,066
EXP_OM_CUSTACCT	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTACCT	CUSTOMER	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563
EXP_OM_CUSTACCT	TOTAL	1.00000000	0.76025399	0.15423452	0.00036539	0.00001522	0.00196384	0.00037632	0.00003719	-	0.00002169	0.00022887	0.00011986	0.00001627	0.00070022	0.00000512	0.00003858	0.08137729	0.00024563
A&G Regulatory																			
Acct 907-910	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	1,446,710	874,501	204,794	478	20	2,496	471	46	-	27	279	146	20	916	7	53	362,099	358
	TOTAL	1,446,710	874,501	204,794	478	20	2,496	471	46	-	27	279	146	20	916	7	53	362,099	358
EXP_OM_CUSTSERV	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_CUSTSERV	CUSTOMER	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
EXP_OM_CUSTSERV	TOTAL	1.00000000	0.60447576	0.14155817	0.00033031	0.00001376	0.00172498	0.00032573	0.00003211	-	0.00001835	0.00019268	0.00010093	0.00001376	0.00063310	0.00000459	0.00003670	0.25029132	0.00024774
O&M Expense	PRODUCTION	100,219,730	50,146,548	12,342,636	151,099	7,536	5,580,901	1,555,851	249,007	-	236,047	4,522,808	20,900,115	2,667,509	1,557,264	29,131	20,702	202,866	49,711
less Purch. Power & Fuel	BULKTRAN	5,091,711	2,553,427	624,822	7,663	382	280,863	78,123	12,650	-	11,928	227,492	1,065,664	135,298	78,134	1,466	1,041	10,263	2,495
	SUBTRAN	1,613,213	787,576	192,321	2,364	152	85,585	23,845	4,875	-	3,563	69,958	417,841	-	23,880	457	319	383	93
	DISTPRI	6,522,908	4,327,575	1,056,123	12,988	-	463,479	129,415	-	-	19,485	377,122	-	-	129,866	2,485	1,754	2,103	512
	DISTSEC	2,386,733	1,821,838	361,734	-	-	139,330	-	-	-	4,801	-	-	-	40,293	-	477	14,802	3,458
	ENERGY	30,456,348	12,083,880	3,461,759	33,548	1,651	1,848,142	552,568	88,616	-	80,343	2,188,122	8,231,416	1,167,409	512,739	9,389	4,401	148,558	43,806
	CUSTOMER	45,035,692	35,123,356	8,220,958	84,311	6,017	149,442	49,109	18,322	-	1,382	35,856	58,203	11,229	48,012	579	3,104	1,112,118	113,694
	TOTAL	191,326,335	106,844,199	26,260,354	291,973	15,738	8,547,741	2,388,912	373,470	-	357,549	7,421,357	30,673,240	3,981,446	2,390,189	43,507	31,798	1,491,092	213,769
EXP_OM_LPP	PRODUCTION	0.52381566	0.26209956	0.06451091	0.00078974	0.00003939	0.02916954	0.00813192	0.00130148	-	0.00123374	0.02363923	0.10923805	0.01394220	0.00813931	0.00015226	0.00010820	0.00106031	0.00025982
EXP_OM_LPP	BULKTRAN	0.02661271	0.01334593	0.00326574	0.00004005	0.00000200	0.00146798	0.00040832	0.00006612	-	0.00006234	0.00118903	0.00556988	0.00070716	0.00040838	0.00000766	0.00000544	0.00005364	0.00001304
EXP_OM_LPP	SUBTRAN	0.00843173	0.00411640	0.00100520	0.00001235	0.00000079	0.00044732	0.00012463	0.00002548	-	0.00001862	0.00036565	0.00218392	-	0.00012481	0.00000239	0.00000167	0.00000200	0.00000049
EXP_OM_LPP	DISTPRI	0.03409310	0.02261881	0.00552001	0.00006789	-	0.00242245	0.00067641	-	-	0.00010184	0.00197109	-	-	0.00067877	0.00001299	0.00000917	0.00001099	0.00000267
EXP_OM_LPP	DISTSEC	0.01247467	0.00952215	0.00189067	-	-	0.00072823	-	-	-	0.00002509	-	-	-	0.00021060	-	0.00000249	0.00007736	0.00001807
EXP_OM_LPP	ENERGY	0.15918534	0.06315848	0.01809348	0.00017534	0.00000863	0.00965963	0.00288809	0.00046317	-	0.00041993	0.01143659	0.04302291	0.00610167	0.00267992	0.00004907	0.00002300	0.00077646	0.00022896
EXP_OM_LPP	CUSTOMER	0.23538679	0.18357826	0.04296825	0.00044067	0.00003145	0.00078109	0.00025668	0.00009576	-	0.00000722	0.00018741	0.00030421	0.00005869	0.00025094	0.00000303	0.00001622	0.00581268	0.00059424
EXP_OM_LPP	TOTAL	1.00000000	0.55843959	0.13725426	0.00152605	0.00008226	0.04467624	0.01248606	0.00195201	-	0.00186879	0.03878900	0.16031896	0.02080971	0.01249273	0.00022740	0.00016620	0.00779345	0.00111730
O&M Labor	PRODUCTION	9,581,657	4,750,668	1,187,989	15,056	754	532,989	146,080	23,246	-	23,040	419,284	2,042,979	260,317	149,066	2,802	2,168	20,371	4,849
	BULKTRAN	2,664,279	1,320,972	330,333	4,187	210	148,203	40,619	6,464	-	6,406	116,586	568,071	72,384	41,449	779	603	5,664	1,348
	SUBTRAN	844,583	407,564	101,685	1,291	83	45,156	12,397	2,492	-	1,914	35,851	222,795	-	12,666	243	185	211	50
	DISTPRI	1,517,702	1,003,838	249,111	3,163	-	108,735	29,901	-	-	4,659	86,056	-	-	30,564	587	449	516	123
	DISTSEC	556,248	422,959	85,371	-	-	32,699	-	-	-	1,148	-	-	-	9,485	-	122	3,635	828
	ENERGY	5,601,410	2,058,062	650,118	8,119	411	329,379	88,858	13,847	-	16,588	327,886	1,723,730	241,034	92,607	1,751	1,747	38,296	8,978
	CUSTOMER	11,203,635	8,671,210	2,045,854	20,835	1,485	36,405	11,614	4,239	-	345	8,352	14,041	2,702	11,769	140	819	346,433	27,393
	TOTAL	31,969,514	18,635,273	4,650,461	52,651	2,942	1,233,566	329,469	50,287	-	54,101	994,015	4,571,616	576,437	347,606	6,303	6,092	415,127	43,569
LABOR_M	PRODUCTION	0.29971231	0.14859993	0.03716007	0.00047096	0.00002357	0.01667178	0.00456935	0.00072712	-	0.00072068	0.01311512	0.06390396	0.00814267	0.00466274	0.00008765	0.00006781	0.00063721	0.00015168
LABOR_M	BULKTRAN	0.08333811	0.04131975	0.01033274	0.00013096	0.00000655	0.00463576	0.00127055	0.00020218	-	0.00020039	0.00364679	0.01776916	0.00226415	0.00129652	0.00002437	0.00001885	0.00017718	0.00004218
LABOR_M	SUBTRAN	0.02641839	0.01274852	0.00318067	0.00004040	0.00000260	0.00141248	0.00038776	0.00007794	-	0.00005986	0.00112142	0.00696899	-	0.00039618	0.00000760	0.00000578	0.00000661	0.00000157
LABOR_M	DISTPRI	0.04747342	0.03139986	0.00779214	0.00009893	-	0.00340122	0.00093531	-	-	0.00014574	0.00269180	-	-	0.00095603	0.00001836	0.00001403	0.00001615	0.00000383
LABOR_M	DISTSEC	0.01739933	0.01323007	0.00267040	-	-	0.00102282	-	-	-	0.00003592	-	-	-	0.00029669	-	0.00000382	0.00011370	0.00002591
LABOR_M	ENERGY	0.17521098	0.06437578	0.02033556	0.00025396	0.00001287	0.01030290	0.00277945	0.00043312	-	0.00051887	0.01025620	0.05391792	0.00753950	0.00289674	0.00005477	0.00005464	0.00119788	0.00028083
LABOR_M	CUSTOMER	0.35044746	0.27123370	0.06399391	0.00065170	0.00004644	0.00113874	0.00036328	0.00013261	-	0.00001080	0.00026125	0.00043919	0.00008451	0.00036814	0.00000439	0.00002562	0.01083634	0.00085684
LABOR_M	TOTAL	1.00000000	0.58290761	0.14546549	0.00164691	0.00009203	0.03858570	0.01030571	0.00157298	-	0.00169226	0.03109258	0.14299923	0.01803083	0.01087304	0.00019715	0.00019056	0.01298508	0.00136284

KENTUCKY POWER COMPANY
COST-OF-SERVICE STUDY
TWELVE MONTHS ENDING
MARCH 31, 2023

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Production O&M Labor	PRODUCTION		9,581,657	4,750,668	1,187,989	15,056	754	532,989	146,080	23,246	-	23,040	419,284	2,042,979	260,317	149,066	2,802	2,168	20,371	4,849
	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY		5,601,410	2,058,062	650,118	8,119	411	329,379	88,858	13,847	-	16,588	327,886	1,723,730	241,034	92,607	1,751	1,747	38,296	8,978
	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL		15,183,067	6,808,730	1,838,107	23,175	1,165	862,367	234,938	37,092	-	39,628	747,170	3,766,708	501,351	241,673	4,553	3,914	58,667	13,827
LABOR_PROD	PRODUCTION		0.63107520	0.31289249	0.07824436	0.00099166	0.00004963	0.03510415	0.00962124	0.00153104	-	0.00151746	0.02761523	0.13455639	0.01714523	0.00981788	0.00018455	0.00014278	0.00134172	0.00031939
LABOR_PROD	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	ENERGY		0.36892480	0.13554985	0.04281863	0.00053474	0.00002709	0.02169382	0.00585242	0.00091197	-	0.00109254	0.02159548	0.11352975	0.01587519	0.00609938	0.00011533	0.00011504	0.00252225	0.00059131
LABOR_PROD	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	TOTAL		1.00000000	0.44844234	0.12106299	0.00152640	0.00007672	0.05679797	0.01547366	0.00244301	-	0.00261000	0.04921072	0.24808613	0.03302042	0.01591727	0.00029989	0.00025782	0.00386397	0.00091070
Rent Revenues	PRODUCTION		895,952	444,221	111,085	1,408	70	49,838	13,659	2,174	-	2,154	39,206	191,033	24,341	13,939	262	203	1,905	453
	BULKTRAN		178,745	88,623	22,162	281	14	9,943	2,725	434	-	430	7,822	38,112	4,856	2,781	52	40	380	90
	SUBTRAN		56,663	27,343	6,822	87	6	3,030	832	167	-	128	2,405	14,947	-	850	16	12	14	3
	DISTPRI		883,210	584,173	144,967	1,840	-	63,277	17,401	-	-	2,711	50,079	-	-	17,786	342	261	300	71
	DISTSEC		354,173	269,305	54,357	-	-	20,820	-	-	-	731	-	-	-	6,039	-	78	2,314	527
	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER		4,530,356	3,597,415	850,428	3,437	136	11,423	2,542	389	-	117	1,642	1,291	250	4,048	34	248	49,083	7,874
	TOTAL		6,899,099	5,011,081	1,189,822	7,053	226	158,331	37,159	3,164	-	6,273	101,154	245,382	29,448	45,443	706	842	53,997	9,020
REV_RENT	PRODUCTION		0.12986507	0.06438822	0.01610142	0.00020407	0.00001021	0.00722387	0.00197989	0.00031506	-	0.00031227	0.00568277	0.02768953	0.00352821	0.00202036	0.00003798	0.00002938	0.00027610	0.00006572
REV_RENT	BULKTRAN		0.02590850	0.01284566	0.00321229	0.00004071	0.00000204	0.00144118	0.00039500	0.00006286	-	0.00006230	0.00113373	0.00552415	0.00070389	0.00040307	0.00000758	0.00000586	0.00005508	0.00001311
REV_RENT	SUBTRAN		0.00821306	0.00396331	0.00098882	0.00001256	0.00000081	0.00043912	0.00012055	0.00002423	-	0.00001861	0.00034863	0.00216655	-	0.00012317	0.00000236	0.00000180	0.00000206	0.00000049
REV_RENT	DISTPRI		0.12801817	0.08467376	0.02101252	0.00026677	-	0.00917183	0.00252219	-	-	0.00039301	0.00725879	-	-	0.00257807	0.00004951	0.00003784	0.00004355	0.00001034
REV_RENT	DISTSEC		0.05133611	0.03903487	0.00787891	-	-	0.00301778	-	-	-	0.00010599	-	-	-	0.00087536	-	0.00001127	0.00033547	0.00007646
REV_RENT	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REV_RENT	CUSTOMER		0.65665909	0.52143259	0.12326649	0.00049820	0.00001967	0.00165572	0.00036845	0.00005644	-	0.00001701	0.00023798	0.00018707	0.00003628	0.00058672	0.00000488	0.00003597	0.00711436	0.00114127
REV_RENT	TOTAL		1.00000000	0.72633841	0.17246046	0.00102231	0.00003273	0.02294950	0.00538607	0.00045859	-	0.00090918	0.01466190	0.03556729	0.00426838	0.00658674	0.00010231	0.00012211	0.00782661	0.00130739
Total Revenues	PRODUCTION		176,236,706	81,811,443	24,127,064	289,946	14,378	12,684,516	3,676,330	439,943	-	491,500	10,285,153	32,935,341	5,003,857	3,801,521	67,149	52,912	432,957	122,695
	BULKTRAN		34,333,949	9,469,715	6,757,646	95,809	5,080	4,416,998	1,272,033	52,961	-	165,615	3,051,888	5,908,498	1,403,044	1,471,241	24,471	26,819	161,207	50,923
	SUBTRAN		10,854,923	3,127,942	2,090,252	29,571	2,005	1,337,493	385,241	21,611	-	49,342	935,601	2,407,194	-	445,127	7,575	8,107	5,987	1,875
	DISTPRI		24,717,090	11,624,676	5,320,661	69,453	-	3,180,086	931,040	-	-	117,282	2,390,682	-	-	1,030,390	17,765	17,038	13,746	4,271
	DISTSEC		7,753,297	4,736,716	1,696,875	-	-	880,193	-	-	-	26,705	-	-	-	293,043	-	4,222	89,133	26,411
	ENERGY		228,484,582	86,066,894	26,456,575	307,368	15,564	13,831,874	3,879,236	608,679	-	660,075	14,746,235	66,561,299	9,495,873	3,894,430	72,570	62,413	1,461,241	364,256
	CUSTOMER		92,917,831	62,605,295	21,884,438	237,022	17,747	510,351	171,605	37,383	-	4,199	115,778	112,068	29,852	182,931	1,980	13,903	6,006,491	986,791
	TOTAL		575,298,378	259,442,682	88,333,510	1,029,169	54,773	36,841,512	10,315,484	1,160,578	-	1,514,718	31,525,337	107,924,399	15,932,627	11,118,683	191,510	185,414	8,170,761	1,557,223
REV	PRODUCTION		0.30633965	0.14220698	0.04193835	0.00050399	0.00002499	0.02204859	0.00639030	0.00076472	-	0.00085434	0.01787794	0.05724915	0.00869785	0.00660791	0.00011672	0.00009197	0.00075258	0.00021327
REV	BULKTRAN		0.05968025	0.01646053	0.01174633	0.00016654	0.00000883	0.00767775	0.00221108	0.00009206	-	0.00028788	0.00530488	0.01027032	0.00243881	0.00255735	0.00004254	0.00004662	0.00028021	0.00008852
REV	SUBTRAN		0.01886834	0.00543708	0.00363334	0.00005140	0.00000349	0.00232487	0.00066964	0.00003757	-	0.00008577	0.00162629	0.00418425	-	0.00077373	0.00001317	0.00001409	0.00001041	0.00000326
REV	DISTPRI		0.04296395	0.02020634	0.00924852	0.00012072	-	0.00552772	0.00161836	-	-	0.00020386	0.00415555	-	-	0.00179105	0.00003088	0.00002962	0.00002389	0.00000742
REV	DISTSEC		0.01347700	0.00823349	0.00294956	-	-	0.00152998	-	-	-	0.00004642	-	-	-	0.00050938	-	0.00000734	0.00015493	0.00004591
REV	ENERGY		0.39715840	0.14960392	0.04598757	0.00053428	0.00002705	0.02404296	0.00674300	0.00105802	-	0.00114736	0.02563233	0.11569874	0.01650600	0.00676941	0.00012614	0.00010849	0.00253997	0.00063316
REV	CUSTOMER		0.16151242	0.10882230	0.03804015	0.00041200	0.00003085	0.00088711	0.00029829	0.00006498	-	0.00000730	0.00020125	0.00019480	0.00005189	0.00031798	0.00000344	0.00002417	0.01044065	0.00171527
REV	TOTAL		1.00000000	0.45097065	0.15354382	0.00178893	0.00009521	0.06403896	0.01793067	0.00201735	-	0.00263293	0.05479824	0.18759726	0.02769454	0.01932681	0.00033289	0.00032229	0.01420265	0.00270681
RBASE		Source: Per Books	488,449,953	217,479,825	77,501,254	937,871	49,423	32,068,115	8,742,658	901,039	-	1,317,898	25,977,052	89,677,755	14,144,263	9,846,521	168,609	179,934	7,976,096	1,481,640
Initial Other Revenue		Revenues;	72,631,740	31,885,119	9,527,843	114,703	6,781	3,929,422	1,165,118	187,878	0	196,820	3,717,392	18,593,389	1,788,364	1,057,768	19,906	18,212	348,520	74,508
Initial Total Expense		Summary tab	529,722,978	256,062,122	72,712,435	860,496	47,842	28,263,452	7,776,863	1,087,381	0	1,249,185	25,025,631	107,057,839	14,626,331	8,114,181	146,282	133,446	5,582,455	977,039
Net Operating Income			31,358,715	(6,697,178)	14,316,662	192,078	8,363	7,734,084	2,130,914	1,536	-	265,532	4,668,812	1,213,305	1,306,296	2,790,108	42,233	64,700	2,742,161	579,108
RATEBASE	PRODUCTION		0.26496409	0.13086097	0.03282263	0.00037611	0.00000899	0.01481483	0.00393663	0.00062573	-	0.00063493	0.01126628	0.05729719	0.00725467	0.00421367	0.00007933	0.00006133	0.00057351	0.00013727
RATEBASE	BULKTRAN		0.22545144	0.11144764	0.02793514	0.00032856	0.00001014	0.01258949	0.00337081	0.00053593	-	0.00054077	0.00965325	0.04859066	0.00616178	0.00356610	0.00006712	0.00005192	0.00048598	0.00011615
RATEBASE	SUBTRAN		0.06931518	0.03333245	0.00833643	0.00009802	0.00000382	0.00371925	0.00099673	0.00020017	-	0.00015658	0.00287588	0.01848136	-	0.00105697	0.00002030	0.00001544	0.00001759	0.00000419
RATEBASE	DISTPRI		0.10362927	0.06855807	0.01705389	0.00020063	-	0.00747811	0.00200809	-	-	0.00031837	0.00576606	-	-	0.00212940	0.00004095	0.00003129	0.00003586	0.00000855
RATEBASE	DISTSEC		0.03389387	0.02573897	0.00520781	-	-	0.00200401	-	-	-	0.00006992	-	-	-	0.00058899	-	0.00000759	0.00022506	0.00005151
RATEBASE	ENERGY		0.02895961	0.01064371	0.00335715	0.00004061	0.00000178	0.00170578	0.00045751	0.00007133	-	0.00008542	0.00169018	0.00891715	0.00124508	0.00048168	0.00000911	0.00000897	0.00019756	0.00004659
RATEBASE	CUSTOMER		0.27378654	0.20409432	0.05018092	0.00051411	0.00002284	0.00093525	0.00028722	0.00011501	-	0.00000863	0.00021022	0.00039362	0.00007592	0.00030337	0.00000355	0.00002172	0.01465523	0.00196462
RATEBASE	TOTAL		1.00000000	0.58467612	0.14489397	0.00155804	0.00004757	0.04324672	0.01105699	0.00154817	-	0.00181463	0.03146187	0.13367998	0.01473746	0.01234019	0.00022034	0.00019827	0.01619081	0.00232888
NOI - Functionalized	PRODUCTION		9,247,910	(1,498,948)	3,243,133	46,368	1,581	2,649,430	758,672	621	-	92,909	1,671,870	520,040	643,038	952,708	15,205	20,014	97,133	34,135
	BULKTRAN		7,873,645	(1,276,578)	2,760,211	40,505	1,783	2,251,458	649,626	532	-	79,130	1,432,503	441,018	546,167	806,293	12,864	16,943	82,309	28,882
	SUBTRAN		2,181,433	(381,807)	823,704	12,084	671	665,137	192,090	199	-	22,913	426,769	167,740	-	238,980	3,891	5,038	2,980	1,043
	DISTPRI		4,058,813	(785,299)	1,685,058	24,735	-	1,337,358	387,002	-	-	46,586	855,659	-	-	481,455	7,848	10,211	6,074	2,126
	DISTSEC		774,940	(294,827)	514,573	-	-	358,389	-	-	-	10,232	-	-	-	133,171	-	2,477	38,118	12,808
	ENERGY		1,221,647	(121,918)	331,713	5,006	313	305,056	88,171	71	-	12,500	250,815	80,934	110,361	108,908	1,745	2,928	33,460	11,584
	CUSTOMER		6,000,326	(2,337,800)	4,958,269	63,380	4,014	167,256	55,352	114	-	1,263	31,196	3,573	6,730	68,593	680	7,089	2,482,088	488,530
	TOTAL		31,358,715	(6,697,178)	14,316,662	192,078	8,363	7,734,084	2,130,914	1,536	-	265,532	4,668,812	1,213,305	1,306,296	2,790,108	42,233	64,700	2,742,161	579,108

ALLOCATOR	FUNCTION		Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
Total Expenses	PRODUCTION		160,211,385	78,425,619	20,371,640	253,177	13,345	9,629,941	2,718,099	397,448	-	398,591	7,780,393	32,589,966	4,360,819	2,748,765	50,479	37,916	346,735	88,450
	BULKTRAN		27,403,540	11,748,159	4,018,204	55,155	3,296	2,144,699	609,899	59,952	-	86,485	1,605,084	5,436,973	856,877	655,053	11,510	10,804	79,362	22,028
	SUBTRAN		8,954,142	3,809,724	1,272,776	17,441	1,334	666,218	189,463	24,226	-	26,429	504,622	2,227,837	-	203,218	3,655	3,344	3,024	831
	DISTPRI		19,800,313	11,926,165	3,551,135	46,418	-	1,763,437	504,093	-	-	70,696	1,383,165	-	-	527,412	9,614	8,102	7,935	2,142
	DISTSEC		6,729,685	4,835,648	1,155,493	-	-	499,940	-	-	-	16,473	-	-	-	153,771	-	2,060	52,715	13,584
	ENERGY		222,559,026	82,972,410	25,760,767	308,782	15,624	13,228,824	3,646,453	571,150	-	647,575	13,675,196	66,694,142	9,385,512	3,715,429	69,758	63,368	1,451,586	352,450
	CUSTOMER		84,064,888	62,344,398	16,582,420	179,522	14,242	330,394	108,856	34,606	-	2,936	77,171	108,922	23,122	110,533	1,266	7,851	3,641,097	497,553
	TOTAL		529,722,978	256,062,122	72,712,435	860,496	47,842	28,263,452	7,776,863	1,087,381	-	1,249,185	25,025,631	107,057,839	14,626,331	8,114,181	146,282	133,446	5,582,455	977,039
Total Revenue	PRODUCTION		169,459,294	76,926,670	23,614,774	299,545	14,926	12,279,371	3,476,771	398,069	-	491,500	9,452,263	33,110,006	5,003,857	3,701,473	65,684	57,930	443,868	122,585
	BULKTRAN		35,277,185	10,471,581	6,778,415	95,660	5,079	4,396,157	1,259,525	60,483	-	165,615	3,037,587	5,877,991	1,403,044	1,461,346	24,374	27,747	161,671	50,910
	SUBTRAN		11,135,575	3,427,917	2,096,480	29,526	2,005	1,331,356	381,554	24,425	-	49,342	931,391	2,395,577	-	442,198	7,546	8,382	6,004	1,874
	DISTPRI		23,859,126	11,140,866	5,236,193	71,153	-	3,100,795	891,095	-	-	117,282	2,238,825	-	-	1,008,866	17,462	18,313	14,009	4,268
	DISTSEC		7,504,625	4,540,821	1,670,066	-	-	858,329	-	-	-	26,705	-	-	-	286,943	-	4,537	90,833	26,392
	ENERGY		223,780,673	82,850,491	26,092,480	313,788	15,938	13,533,880	3,734,624	571,220	-	660,075	13,926,012	66,775,075	9,495,873	3,824,337	71,503	66,296	1,485,046	364,035
	CUSTOMER		90,065,214	60,006,597	21,540,689	242,902	18,256	497,650	164,208	34,720	-	4,199	108,366	112,494	29,852	179,126	1,946	14,941	6,123,185	986,083
	TOTAL		561,081,693	249,364,944	87,029,097	1,052,574	56,204	35,997,537	9,907,776	1,088,917	-	1,514,718	29,694,444	108,271,144	15,932,627	10,904,289	188,515	198,146	8,324,616	1,556,148
Total Other Revenue	PRODUCTION		(56,629,519)	(28,487,817)	(6,822,765)	(85,075)	(4,019)	(3,114,749)	(802,446)	(128,438)	-	(128,515)	(2,364,924)	(12,063,303)	(1,553,385)	(893,449)	(16,795)	(12,993)	(121,782)	(29,065)
	BULKTRAN		64,689,043	32,092,076	8,012,416	101,621	5,090	3,604,271	991,305	155,062	-	155,778	2,834,671	13,767,937	1,757,987	1,006,890	18,927	14,643	137,616	32,755
	SUBTRAN		20,504,468	9,901,447	2,466,514	31,348	2,022	1,098,151	302,490	59,800	-	46,529	871,653	5,400,091	-	307,678	5,902	4,489	5,137	1,219
	DISTPRI		1,153,815	700,132	217,573	3,024	-	88,007	34,530	-	-	4,836	84,251	-	-	20,331	390	298	360	82
	DISTSEC		429,495	313,355	77,209	-	-	27,599	-	-	-	1,211	-	-	-	6,752	-	87	2,692	590
	ENERGY		37,317,050	13,439,801	4,459,913	56,513	3,027	2,211,113	633,643	100,225	-	116,791	2,288,527	11,486,469	1,583,391	605,168	11,443	11,414	250,944	58,669
	CUSTOMER	Check (SB=0)	5,167,389	3,926,126	1,116,982	7,272	662	15,028	5,597	1,230	-	189	3,213	2,195	371	4,399	38	273	73,555	10,258
	TOTAL	-	72,631,740	31,885,119	9,527,843	114,703	6,781	3,929,422	1,165,118	187,878	-	196,820	3,717,392	18,593,389	1,788,364	1,057,768	19,906	18,212	348,520	74,508
Year End Mig Revenue	PRODUCTION		226,088,814	105,414,487	30,437,538	384,620	18,945	15,394,119	4,279,217	526,508	-	620,016	11,817,188	45,173,309	6,557,242	4,594,922	82,479	70,923	565,651	151,650
	BULKTRAN		(29,411,858)	(21,620,495)	(1,234,001)	(5,960)	(10)	791,886	268,220	(94,579)	-	9,837	202,916	(7,889,946)	(354,943)	454,456	5,447	13,104	24,055	18,155
	SUBTRAN		(9,368,893)	(6,473,529)	(370,034)	(1,822)	(17)	233,204	79,064	(35,375)	-	2,813	59,737	(3,004,514)	-	134,520	1,644	3,893	867	655
	DISTPRI		22,705,311	10,440,734	5,018,620	68,128	-	3,012,787	856,565	-	-	112,446	2,154,574	-	-	988,535	17,071	18,015	13,649	4,187
	DISTSEC		7,075,130	4,227,466	1,592,857	-	-	830,730	-	-	-	25,493	-	-	-	280,191	-	4,450	88,141	25,802
	ENERGY		186,463,623	69,410,690	21,632,567	257,275	12,911	11,322,766	3,100,981	470,995	-	543,284	11,637,484	55,288,607	7,912,482	3,219,169	60,060	54,882	1,234,102	305,366
	CUSTOMER		84,897,825	56,080,471	20,423,706	235,630	17,594	482,621	158,611	33,489	-	4,009	105,153	110,299	29,481	174,727	1,908	14,667	6,049,631	975,825
	TOTAL		488,449,953	217,479,825	77,501,254	937,871	49,423	32,068,115	8,742,658	901,039	-	1,317,898	25,977,052	89,677,755	14,144,263	9,846,521	168,609	179,934	7,976,096	1,481,640
RSALE	PRODUCTION		0.46286997	0.21581431	0.06231455	0.00078743	0.00003879	0.03151627	0.00876081	0.00107792	-	0.00126935	0.02419324	0.09248298	0.01342459	0.00940715	0.00016886	0.00014520	0.00115805	0.00031047
RSALE	BULKTRAN		(0.06021468)	(0.04426348)	(0.00252636)	(0.00001220)	(0.00000002)	0.00162122	0.00054912	(0.00019363)	-	0.00002014	0.00041543	(0.01615303)	(0.00072667)	0.00093040	0.00001115	0.00002683	0.00004925	0.00003717
RSALE	SUBTRAN		(0.01918086)	(0.01325321)	(0.00075757)	(0.00000373)	(0.00000004)	0.00047744	0.00016187	(0.00007242)	-	0.00000576	0.00012230	(0.00615112)	-	0.00027540	0.00000337	0.00000797	0.00000178	0.00000134
RSALE	DISTPRI		0.04648442	0.02137524	0.01027458	0.00013948	-	0.00616806	0.00175364	-	-	0.00023021	0.00441104	-	-	0.00202382	0.00003495	0.00003688	0.00002794	0.00000857
RSALE	DISTSEC		0.01448486	0.00865486	0.00326104	-	-	0.00170075	-	-	-	0.00005219	-	-	-	0.00057363	-	0.00000911	0.00018045	0.00005282
RSALE	ENERGY		0.38174560	0.14210400	0.04428820	0.00052672	0.00002643	0.02318102	0.00634862	0.00096427	-	0.00111226	0.02382534	0.11319196	0.01619917	0.00659058	0.00012296	0.00011236	0.00252657	0.00062517
RSALE	CUSTOMER		0.17381069	0.11481314	0.04181330	0.00048240	0.00003602	0.00098807	0.00032472	0.00006856	-	0.00000821	0.00021528	0.00022581	0.00006036	0.00035772	0.00000391	0.00003003	0.01238536	0.00199780
RSALE	TOTAL		1.00000000	0.44524485	0.15866775	0.00192010	0.00010118	0.06565282	0.01789878	0.00184469	-	0.00269812	0.05318263	0.18359661	0.02895745	0.02015871	0.00034519	0.00036838	0.01632940	0.00303335

Calculation of CUST_DEP Allocator

ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
CUST_DEP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	1.00000000	0.65295738	0.14288056	0.00814268	0.00209765	0.03272765	0.02277538	0.00330395	-	0.00199929	0.06833709	0.05111424	0.00955899	0.00080533	-	-	0.00329981	-
	TOTAL	1.00000000	0.65295738	0.14288056	0.00814268	0.00209765	0.03272765	0.02277538	0.00330395	-	0.00199929	0.06833709	0.05111424	0.00955899	0.00080533		-	0.00329981	-
RB_GUP	PRODUCTION	0.32461816	0.16094846	0.04024804	0.00051010	0.00002553	0.01805719	0.00494906	0.00078755	-	0.00078057	0.01420497	0.06921433	0.00881932	0.00505021	0.00009493	0.00007344	0.00069016	0.00016429
	BULKTRAN	0.20806577	0.10316079	0.02579720	0.00032695	0.00001636	0.01157385	0.00317213	0.00050478	-	0.00050031	0.00910475	0.04436330	0.00565279	0.00323696	0.00006085	0.00004707	0.00044236	0.00010530
	SUBTRAN	0.06591740	0.03180925	0.00793620	0.00010079	0.00000650	0.00352433	0.00096752	0.00019448	-	0.00014935	0.00279810	0.01738856	-	0.00098853	0.00001896	0.00001442	0.00001650	0.00000392
	DISTPRI	0.09771876	0.06463313	0.01603927	0.00020363	-	0.00700103	0.00192523	-	-	0.00029999	0.00554077	-	-	0.00196789	0.00003780	0.00002889	0.00003324	0.00000789
	DISTSEC	0.03240895	0.02464307	0.00497403	-	-	0.00190515	-	-	-	0.00006691	-	-	-	0.00055262	-	0.00000711	0.00021178	0.00004827
	ENERGY	0.00972982	0.00357492	0.00112927	0.00001410	0.00000071	0.00057214	0.00015435	0.00002405	-	0.00002881	0.00056955	0.00299417	0.00041868	0.00016086	0.00000304	0.00000303	0.00006652	0.00001559
	CUSTOMER	0.26154114	0.19520993	0.04788404	0.00053005	0.00003905	0.00088830	0.00027943	0.00011201	-	0.00000825	0.00020499	0.00037123	0.00007196	0.00028438	0.00000332	0.00002035	0.01379262	0.00184123
	TOTAL	1.00000000	0.58397954	0.14400805	0.00168563	0.00008815	0.04352200	0.01144771	0.00162287	-	0.00183419	0.03242314	0.13433159	0.01496276	0.01224146	0.00021890	0.00019432	0.01525319	0.00218650
CUST_DEP_FXNL	PRODUCTION	0.31123443	0.17995919	0.03993292	0.00246410	0.00060749	0.01357864	0.00984622	0.00160335	-	0.00085082	0.02993931	0.02633660	0.00563424	0.00033224	-	-	0.00014931	-
CUST_DEP_FXNL	BULKTRAN	0.19948739	0.11534582	0.02559522	0.00157938	0.00038937	0.00870330	0.00631099	0.00102767	-	0.00054534	0.01918976	0.01688059	0.00361130	0.00021295	-	-	0.00009570	-
CUST_DEP_FXNL	SUBTRAN	0.06179842	0.03556646	0.00787406	0.00048690	0.00015462	0.00265022	0.00192489	0.00039593	-	0.00016279	0.00589745	0.00661649	-	0.00006503	-	-	0.00000357	-
CUST_DEP_FXNL	DISTPRI	0.11040141	0.07226739	0.01591369	0.00098368	-	0.00526463	0.00383028	-	-	0.00032699	0.01167809	-	-	0.00012946	-	-	0.00000719	-
CUST_DEP_FXNL	DISTSEC	0.03407666	0.02755383	0.00493508	-	-	0.00143264	-	-	-	0.00007294	-	-	-	0.00003636	-	-	0.00004582	-
CUST_DEP_FXNL	ENERGY	0.00865260	0.00399717	0.00112043	0.00006813	0.00001700	0.00043024	0.00030708	0.00004897	-	0.00003141	0.00120041	0.00113931	0.00026748	0.00001058	-	-	0.00001439	-
CUST_DEP_FXNL	CUSTOMER	0.27434909	0.21826751	0.04750914	0.00256050	0.00092917	0.00066798	0.00055593	0.00022803	-	0.00000899	0.00043206	0.00014126	0.00004597	0.00001871	-	-	0.00298384	-
CUST_DEP_FXNL	TOTAL	1.00000000	0.65295738	0.14288056	0.00814268	0.00209765	0.03272765	0.02277538	0.00330395	-	0.00199929	0.06833709	0.05111424	0.00955899	0.00080533	-	-	0.00329981	-

REVYEC_EXP_OM allocator is the basis to allocate the O&M portion of the Customer Annualization (Year End Customer) Adjustment. It is spread to the functions within each tariff class using total O&M.

ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
REVYEC Total	TOTAL	1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092
EXP_OM	PRODUCTION	0.28437940	0.14217640	0.03504434	0.00043039	0.00002147	0.01583457	0.00440764	0.00070506	-	0.00067107	0.01279845	0.05942573	0.00758343	0.00441932	0.00008271	0.00005925	0.00057827	0.00014132
	BULKTRAN	0.01313933	0.00658921	0.00161238	0.00001977	0.00000099	0.00072478	0.00020160	0.00003264	-	0.00003078	0.00058705	0.00274998	0.00034914	0.00020163	0.00000378	0.00000269	0.00002648	0.00000644
	SUBTRAN	0.00416295	0.00203237	0.00049629	0.00000610	0.00000039	0.00022085	0.00006153	0.00001258	-	0.00000919	0.00018053	0.00107825	-	0.00006162	0.00000118	0.00000082	0.00000099	0.00000024
	DISTPRI	0.01683258	0.01116745	0.00272536	0.00003352	-	0.00119602	0.00033396	-	-	0.00005028	0.00097318	-	-	0.00033512	0.00000641	0.00000453	0.00000543	0.00000132
	DISTSEC	0.00615905	0.00470131	0.00093347	-	-	0.00035955	-	-	-	0.00001239	-	-	-	0.00010398	-	0.00000123	0.00003820	0.00000892
	ENERGY	0.55911055	0.20773373	0.06470356	0.00078306	0.00003954	0.03302494	0.00904858	0.00141650	-	0.00163034	0.03377419	0.16911159	0.02368964	0.00926746	0.00017445	0.00016120	0.00366854	0.00088322
	CUSTOMER	0.11621613	0.09063701	0.02121446	0.00021757	0.00001553	0.00038564	0.00012673	0.00004728	-	0.00000357	0.00009253	0.00015019	0.00002898	0.00012390	0.00000149	0.00000801	0.00286986	0.00029339
	TOTAL	1.00000000	0.46503748	0.12672986	0.00149041	0.00007792	0.05174635	0.01418004	0.00221407	-	0.00240762	0.04840592	0.23251575	0.03165119	0.01451302	0.00027002	0.00023773	0.00718776	0.00133485
REVYEC_EXP_OM	PRODUCTION	0.29136813	(0.09222448)	0.03473157	(0.00442244)	(0.00020944)	0.07488453	0.04945208	0.01211961	-	-	0.25709331	(0.04706536)	-	0.01520742	-	(0.00168532)	(0.00657379)	0.00006044
REVYEC_EXP_OM	BULKTRAN	0.01329532	(0.00427417)	0.00159798	(0.00020319)	(0.00000961)	0.00342760	0.00226187	0.00056113	-	-	0.01179259	(0.00217800)	-	0.00069383	-	(0.00007640)	(0.00030106)	0.00000275
REVYEC_EXP_OM	SUBTRAN	0.00400809	(0.00131832)	0.00049186	(0.00006268)	(0.00000382)	0.00104446	0.00069039	0.00021626	-	-	0.00362643	(0.00085398)	-	0.00021205	-	(0.00002343)	(0.00001124)	0.00000010
REVYEC_EXP_OM	DISTPRI	0.02502821	(0.00724391)	0.00270104	(0.00034440)	-	0.00565620	0.00374692	-	-	-	0.01954902	-	-	0.00115321	-	(0.00012874)	(0.00006169)	0.00000056
REVYEC_EXP_OM	DISTSEC	(0.00053172)	(0.00304957)	0.00092514	-	-	0.00170035	-	-	-	-	-	-	-	0.00035780	-	(0.00003504)	(0.00043422)	0.00000382
REVYEC_EXP_OM	ENERGY	0.73348942	(0.13474906)	0.06412609	(0.00804625)	(0.00038568)	0.15618086	0.10152163	0.02434880	-	-	0.67845101	(0.13393691)	-	0.03189050	-	(0.00458508)	(0.04170425)	0.00037776
REVYEC_EXP_OM	CUSTOMER	(0.06665744)	(0.05879282)	0.02102512	(0.00223559)	(0.00015144)	0.00182377	0.00142185	0.00081273	-	-	0.00185869	(0.00011895)	-	0.00042634	-	(0.00022784)	(0.03262478)	0.00012549
REVYEC_EXP_OM	TOTAL	1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092

ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PRI	GS-SUB	LGS-SEC	LGS-PRI	LGS-SUB	LGS-TRA	IGS-SEC	IGS-PRI	IGS-SUB	IGS-TRA	PS-SEC	PS-PRI	MW	OL	SL
REVYEC_FXNL is a spreading of the REVYEC allocator to each function within the tariff classes using the RSALE allocator.																			
REVYEC TOTAL		1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092
RSALE	PRODUCTION	0.46286997	0.21581431	0.06231455	0.00078743	0.00003879	0.03151627	0.00876081	0.00107792	-	0.00126935	0.02419324	0.09248298	0.01342459	0.00940715	0.00016886	0.00014520	0.00115805	0.00031047
	BULKTRAN	(0.06021468)	(0.04426348)	(0.00252636)	(0.00001220)	(0.00000002)	0.00162122	0.00054912	(0.00019363)	-	0.00002014	0.00041543	(0.01615303)	(0.00072667)	0.00093040	0.00001115	0.00002683	0.00004925	0.00003717
	SUBTRAN	(0.01918086)	(0.01325321)	(0.00075757)	(0.00000373)	(0.00000004)	0.00047744	0.00016187	(0.00007242)	-	0.00000576	0.00012230	(0.00615112)	-	0.00027540	0.00000337	0.00000797	0.00000178	0.00000134
	DISTPRI	0.04648442	0.02137524	0.01027458	0.00013948	-	0.00616806	0.00175364	-	-	0.00023021	0.00441104	-	-	0.00202382	0.00003495	0.00003688	0.00002794	0.00000857
	DISTSEC	0.01448486	0.00865486	0.00326104	-	-	0.00170075	-	-	-	0.00005219	-	-	-	0.00057363	-	0.00000911	0.00018045	0.00005282
	ENERGY	0.38174560	0.14210400	0.04428820	0.00052672	0.00002643	0.02318102	0.00634862	0.00096427	-	0.00111226	0.02382534	0.11319196	0.01619917	0.00659058	0.00012296	0.00011236	0.00252657	0.00062517
	CUSTOMER	0.17381069	0.11481314	0.04181330	0.00048240	0.00003602	0.00098807	0.00032472	0.00006856	-	0.00000821	0.00021528	0.00022581	0.00006036	0.00035772	0.00000391	0.00003003	0.01238536	0.00199780
	TOTAL	1.00000000	0.44524485	0.15866775	0.00192010	0.00010118	0.06565282	0.01789878	0.00184469	-	0.00269812	0.05318263	0.18359661	0.02895745	0.02015871	0.00034519	0.00036838	0.01632940	0.00303335
REVYEC_FXNL	PRODUCTION	0.47860747	(0.14621368)	0.04932718	(0.00628048)	(0.00029133)	0.11747540	0.07787115	0.02223889	-	-	0.44234007	(0.09276335)	-	0.02330526	-	(0.00266527)	(0.00579480)	0.00005844
REVYEC_FXNL	BULKTRAN	0.06038581	0.02998840	(0.00199983)	0.00009733	0.00000016	0.00604303	0.00488094	(0.00399485)	-	-	0.00759553	0.01620200	-	0.00230498	-	(0.00049244)	(0.00024643)	0.00000700
REVYEC_FXNL	SUBTRAN	0.01906677	0.00897902	(0.00059968)	0.00002975	0.00000027	0.00177963	0.00143877	(0.00149417)	-	-	0.00223609	0.00616977	-	0.00068228	-	(0.00014631)	(0.00000888)	0.00000025
REVYEC_FXNL	DISTPRI	0.11596600	(0.01448167)	0.00813319	(0.00111247)	-	0.02299114	0.01558736	-	-	-	0.08064984	-	-	0.00501381	-	(0.00067698)	(0.00013983)	0.00000161
REVYEC_FXNL	DISTSEC	0.00341808	(0.00586365)	0.00258139	-	-	0.00633946	-	-	-	-	-	-	-	0.00142112	-	(0.00016722)	(0.00090296)	0.00000994
REVYEC_FXNL	ENERGY	0.42093185	(0.09627512)	0.03505781	(0.00420106)	(0.00019853)	0.08640614	0.05643017	0.01989413	-	-	0.43561343	(0.11353511)	-	0.01632750	-	(0.00206243)	(0.01264275)	0.00011767
REVYEC_FXNL	CUSTOMER	(0.09837598)	(0.07778563)	0.03309873	(0.00384761)	(0.00027055)	0.00368297	0.00288633	0.00141453	-	-	0.00393608	(0.00022650)	-	0.00088621	-	(0.00055120)	(0.06197537)	0.00037602
REVYEC_FXNL	TOTAL	1.00000000	(0.30165233)	0.12559881	(0.01531454)	(0.00075999)	0.24471777	0.15909472	0.03805852	-	-	0.97237105	(0.18415320)	-	0.04994116	-	(0.00676185)	(0.08171103)	0.00057092
FORF_DISC_FXNL Calculation - In order to properly assign forfeited discounts to the various functions within the customer classes, allocate it using the RSALE allocator																			
FORF_DISC TOTAL		1.00000000	(0.01592420)	0.42031329	0.00698850	0.00071987	0.09220040	0.08283655	0.01033495	-	0.01128997	0.18058238	0.19996340	0.00821749	-	-	-	0.00247739	-
RSALE	PRODUCTION	0.46286997	0.21581431	0.06231455	0.00078743	0.00003879	0.03151627	0.00876081	0.00107792	-	0.00126935	0.02419324	0.09248298	0.01342459	0.00940715	0.00016886	0.00014520	0.00115805	0.00031047
	BULKTRAN	(0.06021468)	(0.04426348)	(0.00252636)	(0.00001220)	(0.00000002)	0.00162122	0.00054912	(0.00019363)	-	0.00002014	0.00041543	(0.01615303)	(0.00072667)	0.00093040	0.00001115	0.00002683	0.00004925	0.00003717
	SUBTRAN	(0.01918086)	(0.01325321)	(0.00075757)	(0.00000373)	(0.00000004)	0.00047744	0.00016187	(0.00007242)	-	0.00000576	0.00012230	(0.00615112)	-	0.00027540	0.00000337	0.00000797	0.00000178	0.00000134
	DISTPRI	0.04648442	0.02137524	0.01027458	0.00013948	-	0.00616806	0.00175364	-	-	0.00023021	0.00441104	-	-	0.00202382	0.00003495	0.00003688	0.00002794	0.00000857
	DISTSEC	0.01448486	0.00865486	0.00326104	-	-	0.00170075	-	-	-	0.00005219	-	-	-	0.00057363	-	0.00000911	0.00018045	0.00005282
	ENERGY	0.38174560	0.14210400	0.04428820	0.00052672	0.00002643	0.02318102	0.00634862	0.00096427	-	0.00111226	0.02382534	0.11319196	0.01619917	0.00659058	0.00012296	0.00011236	0.00252657	0.00062517
	CUSTOMER	0.17381069	0.11481314	0.04181330	0.00048240	0.00003602	0.00098807	0.00032472	0.00006856	-	0.00000821	0.00021528	0.00022581	0.00006036	0.00035772	0.00000391	0.00003003	0.01238536	0.00199780
	TOTAL	1.00000000	0.44524485	0.15866775	0.00192010	0.00010118	0.06565282	0.01789878	0.00184469	-	0.00269812	0.05318263	0.18359661	0.02895745	0.02015871	0.00034519	0.00036838	0.01632940	0.00303335
FORF_DISC_FXNL	PRODUCTION	0.44351305	(0.00771861)	0.16507219	0.00286598	0.00027595	0.04426029	0.04054552	0.00603906	-	0.00531146	0.08214850	0.10072741	0.00380961	-	-	-	0.00017569	-
FORF_DISC_FXNL	BULKTRAN	(0.01771738)	0.00158308	(0.00669237)	(0.00004441)	(0.00000015)	0.00227678	0.00254138	(0.00108482)	-	0.00008427	0.00141059	(0.01759300)	(0.00020621)	-	-	-	0.00000747	-
FORF_DISC_FXNL	SUBTRAN	(0.00679258)	0.00047400	(0.00200681)	(0.00001358)	(0.00000025)	0.00067050	0.00074913	(0.00040575)	-	0.00002410	0.00041527	(0.00669946)	-	-	-	-	0.00000027	-
FORF_DISC_FXNL	DISTPRI	0.05968412	(0.00076449)	0.02721753	0.00050765	-	0.00866219	0.00811594	-	-	0.00096329	0.01497776	-	-	-	-	-	0.00000424	-
FORF_DISC_FXNL	DISTSEC	0.01096325	(0.00030954)	0.00863856	-	-	0.00238847	-	-	-	0.00021839	-	-	-	-	-	-	0.00002738	-
FORF_DISC_FXNL	ENERGY	0.39549771	(0.00508235)	0.11732011	0.00191707	0.00018805	0.03255457	0.02938175	0.00540233	-	0.00465412	0.08089927	0.12328250	0.00459697	-	-	-	0.00038331	-
FORF_DISC_FXNL	CUSTOMER	0.11485184	(0.00410630)	0.11076408	0.00175578	0.00025627	0.00138760	0.00150284	0.00038412	-	0.00003434	0.00073098	0.00024594	0.00001713	-	-	-	0.00187903	-
FORF_DISC_FXNL	TOTAL	1.00000000	(0.01592420)	0.42031329	0.00698850	0.00071987	0.09220040	0.08283655	0.01033495	-	0.01128997	0.18058238	0.19996340	0.00821749	-	-	-	0.00247739	-
WEATHER_FXNL Calculation - In order to properly assign the weather normalization load adjustment to the various functions within the customer classes, allocate it using the RSALE allocator																			
WEATHER_NORM TOTAL		1.00000000	0.86313638	0.08658514	0.00044034	-	0.03106853	0.00876829	-	-	-	-	-	-	0.00975849	0.00024283	-	-	-
RSALE	PRODUCTION	0.46286997	0.21581431	0.06231455	0.00078743	0.00003879	0.03151627	0.00876081	0.00107792	-	0.00126935	0.02419324	0.09248298	0.01342459	0.00940715	0.00016886	0.00014520	0.00115805	0.00031047
	BULKTRAN	(0.06021468)	(0.04426348)	(0.00252636)	(0.00001220)	(0.00000002)	0.00162122	0.00054912	(0.00019363)	-	0.00002014	0.00041543	(0.01615303)	(0.00072667)	0.00093040	0.00001115	0.00002683	0.00004925	0.00003717
	SUBTRAN	(0.01918086)	(0.01325321)	(0.00075757)	(0.00000373)	(0.00000004)	0.00047744	0.00016187	(0.00007242)	-	0.00000576	0.00012230	(0.00615112)	-	0.00027540	0.00000337	0.00000797	0.00000178	0.00000134
	DISTPRI	0.04648442	0.02137524	0.01027458	0.00013948	-	0.00616806	0.00175364	-	-	0.00023021	0.00441104	-	-	0.00202382	0.00003495	0.00003688	0.00002794	0.00000857
	DISTSEC	0.01448486	0.00865486	0.00326104	-	-	0.00170075	-	-	-	0.00005219	-	-	-	0.00057363	-	0.00000911	0.00018045	0.00005282
	ENERGY	0.38174560	0.14210400	0.04428820	0.00052672	0.00002643	0.02318102	0.00634862	0.00096427	-	0.00111226	0.02382534	0.11319196	0.01619917	0.00659058	0.00012296	0.00011236	0.00252657	0.00062517
	CUSTOMER	0.17381069	0.11481314	0.04181330	0.00048240	0.00003602	0.00098807	0.00032472	0.00006856	-	0.00000821	0.00021528	0.00022581	0.00006036	0.00035772	0.00000391	0.00003003	0.01238536	0.00199780
	TOTAL	1.00000000	0.44524485	0.15866775	0.00192010	0.00010118	0.06565282	0.01789878	0.00184469	-	0.00269812	0.05318263	0.18359661	0.02895745	0.02015871	0.00034519	0.00036838	0.01632940	0.00303335
WEATHER_FXNL	PRODUCTION	0.47643456	0.41837021	0.03400511	0.00018058	-	0.01491427	0.00429176	-	-	-	-	-	-	0.00455384	0.00011878	-	-	-
WEATHER_FXNL	BULKTRAN	(0.08569465)	(0.08580766)	(0.00137864)	(0.00000280)	-	0.00076720	0.00026901	-	-	-	-	-	-	0.00045039	0.00000784	-	-	-
WEATHER_FXNL	SUBTRAN	(0.02566556)	(0.02569222)	(0.00041341)	(0.00000086)	-	0.00022594	0.00007930	-	-	-	-	-	-	0.00013332	0.00000237	-	-	-
WEATHER_FXNL	DISTPRI	0.05185838	0.04143730	0.00560685	0.00003199	-	0.00291888	0.00085908	-	-	-	-	-	-	0.00097970	0.00002459	-	-	-
WEATHER_FXNL	DISTSEC	0.01964009	0.01677801	0.00177956	-	-	0.00080484	-	-	-	-	-	-	-	0.00027769	-	-	-	-
WEATHER_FXNL	ENERGY	0.31712362	0.27547793	0.02416811	0.00012079	-	0.01096983	0.00311007	-	-	-	-	-	-	0.00319039	0.00008650	-	-	-
WEATHER_FXNL	CUSTOMER	0.24630356	0.22257281	0.02281756	0.00011063	-	0.00046758	0.00015908	-	-	-	-	-	-	0.00017317	0.00000275	-	-	-
WEATHER_FXNL	TOTAL	1.00000000	0.86313638	0.08658514	0.00044034	-	0.03106853	0.00876829	-	-	-	-	-	-	0.00975849	0.00024283	-	-	-
WEATHER_FXNL_OM	PRODUCTION	0.30323643	0.26388759	0.02394321	0.00012716	-	0.00950708	0.00272548	-	-	-	-	-	-	0.00297153	0.00007438	-	-	-
WEATHER_FXNL_OM	BULKTRAN	0.01403620	0.01222995	0.00110162	0.00000584	-	0.00043516	0.00012466	-	-	-	-	-	-	0.00013557	0.00000340	-	-	-
WEATHER_FXNL_OM	SUBTRAN	0.00432622	0.00377219	0.00033908	0.00000180	-	0.00013260	0.00003805	-	-	-	-	-	-	0.00004144	0.00000106	-	-	-
WEATHER_FXNL_OM	DISTPRI	0.02375508	0.02072744	0.00186204	0.00000990	-	0.00071809	0.00020651	-	-	-	-	-	-	0.00022534	0.00000577	-	-	-
WEATHER_FXNL_OM	DISTSEC	0.00964947	0.00872591	0.00063777	-	-	0.00021587	-	-	-	-	-	-	-	0.00006991	-	-	-	-
WEATHER_FXNL_OM	ENERGY	0.46181599	0.38556579	0.04420716	0.00023135	-	0.01982819	0.00559522	-	-	-	-	-	-	0.00623140	0.00015688	-	-	-
WEATHER_FXNL_OM	CUSTOMER	0.18318062	0.16822752	0.01449427	0.00006428	-	0.00023154	0.00007836	-	-	-	-	-	-	0.00008331	0.00000134	-	-	-
WEATHER_FXNL_OM	TOTAL	1.00000000	0.86313638	0.08658514	0.00044034	-	0.03106853	0.00876829	-	-	-	-	-	-	0.00975849	0.00024283	-	-	-

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended March 31, 2023

					Proposed Revenue Allocation					
Current Class (1)	**Current Revenue** (2)	**Rate Base** (3)	**Current Income** (4)	**Current ROR %** (5)	**Income Increase** (6)	**Income** (7)	**ROR %** (8)	**Revenue Increase** (9)	**Sales Revenue** (10)	**Percent Increase** (11)
RS	227,557,563	1,048,609,520	7,875,268	0.75	40,989,698	48,864,966	4.66	54,921,976	282,479,539	24.14
GS	79,768,125	262,745,215	16,929,836	6.44	10,270,598	27,200,434	10.35	13,761,544	93,529,669	17.25
LGS	53,267,675	122,696,828	14,952,938	12.19	4,796,167	19,749,105	16.10	6,426,370	59,694,045	12.06
IGS	132,601,117	325,865,868	11,140,959	3.42	12,737,959	23,878,918	7.33	17,067,553	149,668,670	12.87
MW	167,202	355,593	53,829	15.14	13,900	67,729	19.05	18,624	185,826	11.14
OL	7,822,241	29,038,015	2,640,420	9.09	1,135,083	3,775,503	13.00	1,520,894	9,343,135	19.44
SL	1,482,715	4,176,817	588,784	14.10	163,270	752,054	18.01	218,765	1,701,480	14.75
Total	502,666,638	1,793,487,856	54,182,034	3.02	70,106,675	124,288,709	6.93	93,935,726	596,602,364	18.69

Gross Rev Conversion Factor: 1.33990

Kentucky Power Company
Current Equalized Results
Twelve Months Ended March 31, 2023

					Current Equalized Rate of Return							
Current Class	Current Revenue	Rate Base	Current Income	Current ROR %	Percent Increase	Revenue Increase	Income Increase	Income	ROR %	Sales Revenue	Current Subsidy	Relative ROR
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)=(11)-(2)	
RS	227,557,563	1,048,609,520	7,875,268	0.75	14.02	31,894,472	23,803,673	31,678,941	3.02	259,452,035	31,894,472	0.25
GS	79,768,125	262,745,215	16,929,836	6.44	-15.10	(12,048,611)	(8,992,191)	7,937,645	3.02	67,719,514	(12,048,611)	2.13
LGS	53,267,675	122,696,828	14,952,938	12.19	-28.29	(15,068,770)	(11,246,215)	3,706,723	3.02	38,198,905	(15,068,770)	4.04
IGS	132,601,117	325,865,868	11,140,959	3.42	-1.31	(1,737,059)	(1,296,412)	9,844,547	3.02	130,864,058	(1,737,059)	1.13
MW	167,202	355,593	53,829	15.14	-34.53	(57,730)	(43,086)	10,743	3.02	109,472	(57,730)	5.01
OL	7,822,241	29,038,015	2,640,420	9.09	-30.20	(2,362,465)	(1,763,169)	877,251	3.02	5,459,776	(2,362,465)	3.01
SL	1,482,715	4,176,817	588,784	14.10	-41.80	(619,837)	(462,601)	126,183	3.02	862,878	(619,837)	4.67
Total	502,666,638	1,793,487,856	54,182,034	3.02	0.00	0	(1)	54,182,033	3.02	502,666,638	0	1.00

Gross Rev Conversion Factor: 1.339897

Kentucky Power Company
Proposed Revenue Allocation
Twelve Months Ended March 31, 2023

					Equalized Rate of Return						100% of	Base	Base
Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)	Sales Revenue (11)	Current Subsidy (12)	Proposed Increase (13)=(7)-(12)	Percent Increase (14)
RS	227,557,563	1,048,609,520	7,875,268	0.75	38.15	86,816,448	64,793,372	72,668,640	6.93	314,374,011	31,894,472	54,921,976	24.14
GS	79,768,125	262,745,215	16,929,836	6.44	2.15	1,712,933	1,278,407	18,208,243	6.93	81,481,058	(12,048,611)	13,761,544	17.25
LGS	53,267,675	122,696,828	14,952,938	12.19	-16.22	(8,642,400)	(6,450,048)	8,502,890	6.93	44,625,275	(15,068,770)	6,426,370	12.06
IGS	132,601,117	325,865,868	11,140,959	3.42	11.56	15,330,494	11,441,546	22,582,505	6.93	147,931,611	(1,737,059)	17,067,553	12.87
MW	167,202	355,593	53,829	15.14	-23.39	(39,106)	(29,186)	24,643	6.93	128,096	(57,730)	18,624	11.14
OL	7,822,241	29,038,015	2,640,420	9.09	-10.76	(841,571)	(628,086)	2,012,334	6.93	6,980,670	(2,362,465)	1,520,894	19.44
SL	1,482,715	4,176,817	588,784	14.10	-27.05	(401,072)	(299,331)	289,453	6.93	1,081,643	(619,837)	218,765	14.75
Total	502,666,638	1,793,487,856	54,182,034	3.02	18.69	93,935,726	70,106,674	124,288,708	6.93	596,602,364	0	93,935,726	18.69
								124,288,708					

Gross Rev Conversion Factor: 1.339897

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	))))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

HEATHER M. WHITNEY

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
HEATHER M. WHITNEY ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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DIRECT TESTIMONY OF
HEATHER M. WHITNEY, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Heather M. Whitney. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation ("AEPSC") as a Director in Regulatory Accounting Services. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company").

II. BACKGROUND

Q. PLEASE DISCUSS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science Degree in Agriculture and a Master of Accounting Degree from The Ohio State University in June 2005. I have been a Certified Public Accountant since 2007, transitioning my Ohio license to inactive status in 2012. I began my career in 2005 as an auditor within Ernst & Young's Columbus, Ohio, Assurance Services practice. I joined AEPSC as an internal auditor in 2008 and held roles of increasing responsibility within the AEPSC Audit Services function through early 2016, when I accepted a role within the AEPSC Accounting function. Since early 2016, I have held roles of increasing responsibility in a diverse set of disciplines within the AEPSC Accounting function, including Manager Derivative Accounting Policy & Research (2016), Director

Commercial Accounting (2017), and Director Tax Accounting & Support Services (2018). I assumed my current role of Director Regulatory Accounting Services in 2019.

Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR IN THE REGULATORY ACCOUNTING SERVICES GROUP?

A. My primary responsibilities in Regulatory Accounting Services involve providing AEP operating subsidiaries, including Kentucky Power, with accounting support for regulatory filings. This accounting support includes the preparation of cost of service adjustments, accounting schedules, testimony, and responses to data requests. Also, I monitor regulatory proceedings, settlements, orders, and legislation for accounting implications and participate in determining the appropriate regulatory accounting and financial reporting treatment of regulatory transactions.

Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY IN A REGULATORY PROCEEDING?

A. Yes, I have testified before the Kentucky Public Service Commission in Case Nos. 2020-00174 and 2022-00283. In addition, I have filed testimony with the Kentucky Public Service Commission in Case No. 2021-00004. I have filed testimony with the Oklahoma Corporation Commission in Cause Nos. 202100055, 202100076, and 2022-000093. I have also filed testimony with the Public Utilities Commission of Texas in Case No. 49494 and with the Public Utilities Commission of Ohio in Case No. 05-376-EL-UNC.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support certain known and measurable adjustments to the Company’s revenues and operating expenses, rate base, and capitalization for the test year ended (twelve months ended) March 31, 2023. I have provided the adjustments to revenues and operating expenses and rate base to Company Witness Walsh to include in the computation of the Company's jurisdictional revenue requirement. I have provided the adjustments to capitalization to Company Witness Walsh to present in Section V, Schedule 3.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes, I am sponsoring Section IV filed with the Company's Application.

IV. <u>SUMMARY OF ADJUSTMENTS</u>

Q. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS THAT YOU HAVE PREPARED FOR THIS CASE.

A. I have prepared three types of adjustments in this case. First, I have prepared numerous adjustments to test year revenue and operating expense amounts. Second, I have prepared adjustments to the Company's rate base. Third, I have prepared adjustments to the Company's capitalization. The adjustments are described in detail in the Revenue and Operating Expense Adjustments, Rate Base Adjustment, and Capitalization Adjustment sections of my testimony.

Q. HOW DID YOU DETERMINE THE APPROPRIATE ALLOCATION FACTORS FOR THE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. For all of the adjustments that I sponsor and, in my testimony, below, I calculated the total Company adjustments and applied operations and maintenance ("O&M") and retail allocation factors (as applicable) that were provided to me by Company Witness Walsh.

Q. DOES THE APPLICATION INCLUDE SUPPORT FOR THE ADJUSTMENTS INCLUDED IN YOUR TESTIMONY?

A. Yes. See Section V, Exhibit 2.

V. REVENUE AND OPERATING EXPENSE ADJUSTMENTS

Q. WHAT TYPES OF REVENUE AND OPERATING EXPENSE ADJUSTMENTS DID YOU PREPARE?

A. The adjustments to test year revenue and operating expense that I prepared fall into five broad categories: (1) rider and surcharge-related adjustments, (2) payroll and benefit-related adjustments, (3) depreciation and asset retirement obligation-related adjustments, (4) regulatory asset amortization-related adjustments, and (5) other O&M adjustments.

Q. CAN YOU PROVIDE A LIST OF THE REVENUE AND OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING?

A. Yes. The table below identifies the revenue and operating expense adjustments that I am sponsoring. The details supporting the calculations of these adjustments are included on referenced pages of Exhibit 2 to Section V of the Application.

Category	Adjustment Description	Reference in Section V, Exhibit 2
Rider and Surcharge Related Adjustments	Remove Tariff D.R. Revenues and Expenses	W02
	Remove Tariff P.P.A. Revenues and Non-Transmission Expenses Recovered Through Tariff P.P.A.	W09
	Remove Tariff D.S.M.C. Revenues and Expenses	W10
	Remove Tariff R.E.A. Revenues and Expenses	W11
	Remove Tariff K.E.D.S. Revenues and Expenses	W12

Category	Adjustment Description	Reference in Section V, Exhibit 2
Payroll and Benefit Adjustments	Adjust Pension and OPEB Expense	W21
	Adjust Employee Related Group Benefit Expense	W22
	Remove Severance Expense	W25
	KPCo Incentive Compensation Expense Adjustment	W27
	KPCo Annualization of Payroll Expense Adjustment	W28
	KPCo Overtime Related to Employee Merit Increases	W29
	KPCo Medicare Tax Expense Adjustment	W30
	KPCo Social Security Tax Expense Adjustment	W31
	KPCo Social Security Tax Base Adjustment	W32
Depreciation and Asset Retirement Obligation Expense Adjustments	Annualization of Depreciation Expense (Excluding ARO Depreciation) at Existing Rates	W34
	Annualization of ARO Depreciation Expense	W35
	Annualization of ARO Accretion Expense	W36
Adjustments Related to Amortization of Jurisdictional Deferrals	Amortization of Big Sandy Unit 1 Operations Rider Deferral	W17
	Amortization of NERC Compliance and Cybersecurity Cost Deferral	W24
	Amortization of Deferred Plant Maintenance Costs	W48
	Remove Certain Regulatory Asset Amortizations Not Recovered Through Base Rates	W59
Other O&M Adjustments	Adjust Interest on Customer Deposits	W15
	Normalization of Storm Damage Expense	W16
	Annualization of Lease Expense	W20
	Normalize Bad Debt Expense	W26
	AFUDC Offset Adjustment	W38
	Remove Adjustment to Joint Use Pole Rental Revenue and Expense Related to a Prior Period	W44
	Remove Non-Ongoing Expense Related to the COVID-19 Pandemic	W45
	Remove Insurance Proceeds Related to Prior Period	W46
	Remove Rockport UPA Non-Fuel Expense, Net of Deferral	W47
	Normalize Non-F.A.C Eligible Purchased Power Expense	W57
	Recover Actual, Incremental Non-F.A.C Eligible Purchased Power Expense Since Last Base Case (Excluding Winter Storm Elliott)	W58

<u>Rider and Surcharge Related Adjustments</u>

Q. DID YOU MAKE ANY COST OF SERVICE ADJUSTMENTS FOR RIDERS WITH OVER-/UNDER-RECOVERY ACCOUNTING?

A. Yes. For riders with over-/under-recovery accounting, I made certain adjustments to remove revenue and expense amounts related to the over-/under-recovery in order to avoid including certain rider-related amounts in the determination of the Company's base rates.

Q. PLEASE DESCRIBE THE BASIS FOR OVER-/UNDER-RECOVERY ACCOUNTING.

A. Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") 980-340-25-1 (regulatory assets) requires deferral accounting based on the existence of a regulatory asset when there is probability of recovery from customers in the future for an under-recovery of costs. ASC 980-405-25-1 (regulatory liabilities) requires deferral accounting based on the existence of a regulatory liability when a true-up to actual costs results in an over-recovery and probability of refund to customers in the future.

Q. FOR WHICH RIDERS DID YOU MAKE TEST YEAR COST OF SERVICE ADJUSTMENTS RELATED TO OVER-/UNDER-RECOVERY?

A. I made adjustments to the test year cost of service for the Decommissioning Rider ("Tariff D.R."), Tariff Purchase Power Adjustment ("Tariff P.P.A."), and Tariff Demand-Side Management Adjustment Clause ("Tariff D.S.M.C.").

Q. PLEASE DESCRIBE THE ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO TARIFF D.R. IN SECTION V, EXHIBIT 2 W02.

A. Because the Company recovers the costs associated with the decommissioning of coal-related assets at Big Sandy through Tariff D.R. and not through base rates, any revenues and expenses related to Tariff D.R. must be removed from the Company's cost of service. Accordingly, I made the following adjustments relating to Tariff D.R. revenue and expense for the test year ended March 31, 2023:

1. A decrease to test year revenue of $(28,713,724) in Accounts 440-444 to remove Tariff D.R. charges from revenue.
2. A removal of both test year Big Sandy coal-related O&M expense of $(3,845) (retail jurisdictional amount) in Accounts 501, 506, and 920 and removal of the corresponding deferral of Big Sandy coal-related O&M expense of $3,845 (retail jurisdictional amount) in Account 512. This removal of offsetting O&M expense and the deferral of O&M expense had no impact on test year cost of service.
3. A removal of both test year asset retirement obligation ("ARO") accretion expense of $(174,650) (retail jurisdictional amount) in Account 411.1 and removal of the corresponding deferral of test year ARO accretion expense of $174,650 (retail jurisdictional amount) in Account 411.1, both related to Big Sandy coal-related ARO accretion expense. This removal of offsetting ARO accretion expense and the deferral of ARO accretion expense had no impact on test year cost of service.
4. A decrease in test year amortization expense of $(13,032,207) (retail jurisdictional amount) in Account 407.3 to remove amortization expense of the net Tariff D.R. regulatory asset.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO TARIFF P.P.A. IN SECTION V, EXHIBIT 2 W09.

A. Because the Company recovers certain purchased power costs through Tariff P.P.A. and not through base rates, any revenues and expenses related to Tariff P.P.A. must be removed from the Company's cost of service. Refer to the adjustment at Section V, Exhibit 2 W23, sponsored by Company Witness Walsh for the Company's adjustment addressing PJM load-serving entity Open Access Transmission Tariff ("OATT") expense. I made the following adjustments relating to Tariff P.P.A. revenue and non-OATT expenses for the test year ended March 31, 2023 (retail jurisdictional amounts):

1. An decrease to test year revenue of $(21,021,955) in Accounts 440-444 to remove Tariff P.P.A. charges from revenue.
2. A decrease to test year O&M expense of $(2,631,871) in Account 555 to remove amortization related to recovery of the Rockport Deferral which began on December 9, 2022, pursuant to the December 8, 2022 Order in Case No. 2022-00283.
3. A decrease to test year O&M expense of $(3,989,249) in Account 555 to remove the net annual cost of credits provided to customers under Tariff Contract Service - Interruptible Power ("C.S.-I.R.P") and Rider Demand Response Service ("D.R.S.").
4. An increase to test year O&M expense of $6,727,358 in Account 566 to remove deferral of the net test year under-recovery of expenses related to Tariff P.P.A.

Refer to Section V, Exhibit 2 W09, Lines 13 through 25 for a reconciliation of test year Tariff P.P.A. revenues to test year recoverable costs, which supports that appropriate adjustments have been made to remove revenues and expenses related to Tariff P.P.A from the Company's cost of service.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO TARIFF D.S.M.C. IN SECTION V, EXHIBIT 2 W10.

A. Tariff D.S.M.C. continues to recover lost revenue, incentives and program costs as previously approved by the Commission. This adjustment involves the removal of all

Tariff D.S.M.C. revenue and O&M expense. The components of these net adjustments for the test year ended March 31, 2023 are described below:

1. Decrease in test year other electric revenues of $(307,780) in Account 456, composed of the following:
    - Remove Demand Side Management ("DSM") Revenues of $(336,159).
    - Remove DSM Over/Under Recovery (Incentives & Lost Revenue) of $46,762.
    - Remove DSM Incentive Revenue Accrued of $(2,656).
    - Remove DSM Lost Revenue Accrued of $(15,727).
2. Decrease in test year O&M expense of $(289,397) in Account 908, composed of the following items related to program costs:
    - Remove DSM Over/Under Recovery (O&M Program Cost) of $(289,397).
    - Remove DSM O&M Program Cost Expense of $(349,051).
    - Remove DSM O&M Program Cost Over/under Deferral of $349,051.

The net DSM adjustments result in decreases of $(307,780) in test year revenue and $(289,397) in test year expense. These decreases are all directly assigned to the Company's retail jurisdiction.

Q. DID YOU MAKE ANY COST OF SERVICE ADJUSTMENTS FOR CERTAIN RIDERS WITHOUT OVER-/UNDER-RECOVERY ACCOUNTING?

A. Yes. I made adjustments to test year cost of service for Tariff Residential Energy Assistance ("Tariff R.E.A.") and Tariff Kentucky Economic Development Surcharge ("Tariff K.E.D.S.").

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO TARIFF R.E.A. IN SECTION V, EXHIBIT 2 W11.

A. For this adjustment, test year retail Tariff R.E.A. revenue of $(476,213) recorded to Accounts 440-444 is removed and corresponding expense of $(476,213) recorded as O&M expense to Account 908 is also removed. These Tariff R.E.A. revenue and expense adjustments are directly assigned to the Company's retail jurisdiction.

Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE SPONSORING RELATED TO THE COMPANY'S TARIFF K.E.D.S. AS DESCRIBED IN SECTION V, EXHIBIT 2 W12.

A. For this adjustment, test year retail Tariff K.E.D.S. revenue of $(372,763) in Accounts 440-444 is removed and corresponding expense of $(372,763) recorded as O&M expense to Account 908 is also removed. These Tariff K.E.D.S. revenue and expense adjustments are directly assigned to the Company's retail jurisdiction.

<u>Payroll and Benefit Adjustments</u>

Q. ARE SPECIAL CONSIDERATIONS NECESSARY WHEN CALCULATING GOING LEVEL COST OF SERVICE ADJUSTMENTS FOR PAYROLL AND BENEFIT RELATED ISSUES?

A. Yes. All of the payroll and benefit cost of service adjustments discussed below properly are limited to Kentucky Power's ownership share of generation plant-related labor costs and are exclusive of amounts properly billed or allocated to Wheeling Power and AEP Generation Resources for their ownership shares of Mitchell Plant and Kammer Plant, respectively.

The Company owns an undivided 50% interest in the Mitchell Plant. Through August 2022, the Company was also the operator of the Mitchell Plant. In September 2022, Wheeling Power Company ("Wheeling Power"), an affiliated AEP subsidiary company and owner of the remaining 50% undivided interest in the Mitchell Plant, became operator of the Mitchell Plant, pursuant to the September 1, 2022 Written Consent Action of the Mitchell Operating Committee. The plant operator initially records 100% of all Mitchell Plant labor costs charged by employees. Then, the plant operator bills the other joint owner of the plant its share of Mitchell Plant labor costs, in accordance with the Mitchell Operating Agreement, including the September 1, 2022 Written Consent Action of the Mitchell Operating Committee. The Mitchell Plant Operating Agreement is included as Exhibit V to Section II of the Company's Application.

In May 2015, AEP Generation Resources Inc. ("AEP Generation Resources"), an affiliated AEP subsidiary company, ceased operations at its Kammer Plant generating facility due to pending environmental regulations. Due to the proximity of Kammer Plant to Mitchell Plant, certain Company employees worked at the Kammer Plant during the ongoing shutdown of the plant facility. Through August 2022, the Company initially recorded 100% of all Kammer Plant retiree pension and other post-retirement benefit costs applicable to these employees and then billed 100% of these retiree costs to AEP Generation Resources. In September 2022, in conjunction with the implementation of the September 1, 2022 Written Consent Action of the Mitchell Operating Committee, these pension and other post-retirement benefit costs were transferred to AGR.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR PENSION AND OTHER POST EMPLOYMENT BENEFITS ("OPEB") (SECTION V, EXHIBIT 2 W21).

A. This adjustment accounts for known changes from test year pension and OPEB costs related to both active and inactive Company employees, and the Company's 50% ownership share of related Mitchell Plant employee costs billed pursuant to the Mitchell Operating Agreement (discussed above). This adjustment is based on 2023 forecasts, as provided by the Company's actuaries, Willis, Towers and Watson, less actual costs for the test year ended March 31, 2023. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the cost of service decrease for pension and OPEB expense is $(811,799).

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR EMPLOYEE GROUP BENEFITS (SECTION V, EXHIBIT 2 W22).

A. This adjustment accounts for known changes from test year values in medical, dental, life and long-term disability coverage for Company employees, and the Company's 50% ownership share of related Mitchell Plant employee costs billed pursuant to the Mitchell Operating Agreement (discussed above). The adjustment is based on the number of employees enrolled in each plan as of March 31, 2023 and actual cost per employee for 2023 compared to actual Company medical, dental, life and long-term disability coverage costs for the test year ended March 31, 2023. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the net cost of service increase for group benefit expense is $77,962.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT RELATED TO SEVERANCE EXPENSE (SECTION V, EXHIBIT 2 W25).

A. This Company considered a cost of service adjustment related to severance expense; however, there was no severance expense in the test year. Therefore, it was not necessary to adjust the test year cost of service.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR THE COMPANY'S INCENTIVE COMPENSATION (SECTION V, EXHIBIT 2 W27).

A. As described by Company Witness Carlin, the AEP System offers two types of incentive pay to its employees: variable annual (or short-term) incentive compensation ("STI") and long-term incentive compensation ("LTI"). Test year cost of service amounts include expenses for STI, also referred to as Incentive Compensation Plan ("ICP") expense, and LTI, which is composed of expenses related to Performance Share Units ("PSUs"), and Restricted Stock Units ("RSUs").

The incentive compensation cost of service adjustment decreases test year ICP and PSU expense to reflect expenses at a level of 1.0 of the incentive target to be paid to employees[1] subject to meeting performance goals. No adjustment to RSU expense is necessary because RSU expense per books is already at a level of 1.0 of the incentive target to be paid to employees[1] subject to meeting performance goals. The retail jurisdictional share of the cost of service decrease for incentive compensation expense is $(512,807).

[1] Company employees, and the Company's 50% ownership share of related Mitchell Plant employee costs billed pursuant to the Mitchell Operating Agreement (discussed above).

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR ANNUALIZATION OF PAYROLL EXPENSE (SECTION V, EXHIBIT 2 W28).

A. This adjustment increases O&M expenses to reflect the annualized base payroll expense for the Company at the test year-end. Base payroll expense in the test year was updated using the actual employees[2] on the payroll in the last pay period of March 2023 and their base payroll amounts at that time ("March 2023 Base Payroll"), resulting in a calculated increase in payroll expense of $1,122,756. Next, annual merit increases and promotions effective in April, May, and June 2023, as approved by the Company and provided by AEPSC's Human Resources department, were applied to March 2023 Base Payroll, resulting in a calculated increase in payroll expense of $645,270. Finally, the total payroll expense increase of $1,768,026 was multiplied by the corresponding retail allocation factor, resulting in a retail jurisdictional O&M expense increase of $1,752,114. The calculation to annualize payroll expense does not include overtime, severance payments, incentive payments and other remunerations.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR ADDITIONAL OVERTIME COSTS RELATED TO MERIT INCREASES (SECTION V, EXHIBIT 2 W29).

A. To account for the impact of increased base pay on the Company's overtime expense, overtime costs for the test year ended March 31, 2023 were multiplied by the approved average merit increase percentages for 2023. After applying the corresponding retail

[2] Company employees, and the Company's 50% ownership share of related Mitchell Plant employee costs billed pursuant to the Mitchell Operating Agreement (discussed above).

allocation factor, the retail jurisdictional share of the cost of service increase for overtime expense related to merit increases is $191,400.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR MEDICARE TAX EXPENSE (SECTION V, EXHIBIT 2 W30).

A. The Company incurs Medicare tax expense for labor costs that include base pay, overtime and incentives. This cost of service adjustment for Medicare tax expense is determined by taking the net increase related to changes in incentives, annualization of base payroll, merit increases, and the impact of merit increases on overtime. This net increase of $1,443,701 is then multiplied by the Medicare tax rate of 1.45%, resulting in a $20,934 increase in Medicare tax expenses. After applying the corresponding retail allocation factor, the retail jurisdictional share of the Medicare tax expense increase is $20,745.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR SOCIAL SECURITY TAX EXPENSE (SECTION V, EXHIBIT 2 W31).

A. The Company incurs Social Security tax expense for labor costs that include base pay, overtime and incentives. This cost of service adjustment for Social Security Tax is determined by taking the net increase related to changes in incentives, annualization of base payroll, merit increases, and the impact of merit increases on overtime. This net increase of $1,443,701 is then multiplied by both the percent of 2022 Company salaries subject to 2022 Social Security tax and the Social Security tax rate of 6.20%, resulting in a $86,198 increase in Company test year Social Security taxes. After applying the corresponding retail allocation factor, the retail jurisdictional share of the Social Security tax expense increase is $85,422.

Q. PLEASE DESCRIBE THE COST OF SERVICE ADJUSTMENT FOR SOCIAL SECURITY TAX BASE (SECTION V, EXHIBIT 2 W32).

A. The Company incurs Social Security tax expense of 6.20% on each employee's combined base pay, overtime and incentive compensation up to the annual Social Security tax base. The tax base on which Social Security taxes are imposed increased from $147,000 in 2022 to $160,200 in 2023. Based on this tax base increase, the number of Company employees who earned more than $147,000 in 2022 and the Social Security tax rate of 6.20%, a net increase in Company Social Security tax expense of $39,283 was calculated. After applying corresponding O&M and retail allocation factors, the retail jurisdictional share of the cost of service increase due to the increase in the Social Security tax base is $22,589.

Depreciation and Asset Retirement Obligation Adjustments

Q. HOW DID THE COMPANY CALCULATE THE ANNUALIZATION OF DEPRECIATION EXPENSE USING COMMISSION-APPROVED DEPRECIATION RATES AS OF MARCH 31, 2023 IN SECTION V, EXHIBIT 2 W34?

A. To properly reflect depreciation expense based on property balances at the end of the test year and to reflect assets placed in service or retired during the test year, I calculated a depreciation annualization adjustment by multiplying the Company's March 31, 2023 gross plant balances for each functional class by corresponding depreciation rates used in March 2023. The resulting adjusted Current Annual Depreciation Expense is then compared to the corresponding 12 Month Test Year per Books Depreciation Expense, resulting in a total Company increase in depreciation expense of $2,127,089. After applying corresponding allocation factors to each functional class's depreciation expense increase, the retail jurisdictional amount of the depreciation expense increase is $2,109,351.

Q. WHAT ADJUSTMENTS WERE MADE TO ARRIVE AT TEST YEAR PER BOOKS DEPRECIATION?

A. Adjustments were made to remove property balances and depreciation expense for the test year ended March 31, 2023 related to the Company's (1) Mitchell Plant Flue Gas Desulfurization ("FGD") investment, (2) North American Electric Reliability Corporation ("NERC") Compliance and Cybersecurity Cost Deferral, and (3) AROs.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE ANNUALIZATION OF DEPRECIATION EXPENSE RELATED TO THE MITCHELL PLANT FGD.

A. For the calculation of the annualization of depreciation in Section V, Exhibit 2 W34, March 31, 2023 property balances are reduced by $(329,731,526) related to Mitchell Plant FGD plant in service while test year per books depreciation expense is also reduced by $(9,759,570) for depreciation expense in the test year ended March 31, 2023 related to Mitchell Plant FGD plant in service. These adjustments are sponsored and described by Company Witness Kahn.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE ANNUALIZATION OF DEPRECIATION EXPENSE RELATED TO THE NERC COMPLIANCE AND CYBERSECURITY COST DEFERRAL.

A. For the calculation of the annualization of depreciation expense in Section V, Exhibit 2 W34, March 31, 2023 property balances are reduced by $(3,843,227) related to gross plant in service being recovered through the NERC Compliance and Cybersecurity Cost Deferral. Test year per books depreciation expense was increased by $722,995 to remove deferral of depreciation expense (net of deferral amortization) in the test year ended March 31, 2023 being recovered through the NERC Compliance and Cybersecurity Cost Deferral.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE IN THE ANNUALIZATION OF DEPRECIATION EXPENSE RELATED TO ARO.

A. For the calculation of the annualization of depreciation expense in Section V, Exhibit 2 W34, March 31, 2023 property balances are decreased by $(11,395,238) to remove ARO property balances while depreciation expense for the test year ended March 31, 2023 is reduced by $(62,537) to remove test year ARO depreciation expense on Mitchell Plant.

Q. PLEASE DESCRIBE THE ANNUALIZATION OF ARO DEPRECIATION EXPENSE IN SECTION V, EXHIBIT 2 W35.

A. The ARO depreciation annualization adjustment increases depreciation expense by $471,246. The depreciation annualization adjustment is calculated by comparing annualized March 2023 ARO depreciation expense of $540,960 to per books ARO depreciation expense for the test year ended March 31, 2023 of $62,537 (related to the Company's share of Mitchell Plant AROs), resulting in a total Company ARO depreciation increase of $478,422. The retail jurisdictional amount of the ARO depreciation increase is $471,246.

The increase in ARO depreciation expense from the test year per book amount is due to including asbestos ARO costs related to Big Sandy, Unit 1 and General Plant in the cost of service. Currently, these amounts are being deferred to Account 108.0013. Upon inclusion of a level of ARO depreciation expense for asbestos removal costs in base rates, the Company will cease deferral to Account 108.0013 and reclass the cumulative deferral to Account 108.0001. This will complete the Company's expected accounting related to implementation of FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (as codified in ASC 410, Asset Retirement and Environmental Obligations).

Q. PLEASE DESCRIBE THE ANNUALIZATION OF ARO ACCRETION EXPENSE IN SECTION V, EXHIBIT 2 W36.

A. This adjustment increases other expense by $255,569. This increase was calculated by comparing annualized March 2023 ARO accretion expense of $817,529 to per books ARO accretion expense for the test year ended March 31, 2023 of $558,068 (related to the Company's share of Mitchell Plant AROs), resulting in a total Company increase of $259,461. The retail jurisdictional amount of the ARO accretion expense increase is $255,569.

The increase in ARO accretion expense from the test year per book amount is due to including (1) Big Sandy coal-related ARO costs and (2) asbestos ARO costs related to Big Sandy, Unit 1 and General Plant in the cost of service.

Currently, Big Sandy coal-related ARO costs are being recovered through Tariff D.R.; however, given the Company's proposal to securitize the regulatory assets recoverable through Tariff D.R., the Company is proposing to recover remaining Big Sandy coal-related ARO accretion expense through base rates going forward.

Currently, asbestos removal costs related to Big Sandy, Unit 1 and General Plant are being deferred to Account 108.0013. Upon inclusion of a level of ARO accretion expense for asbestos removal costs in base rates, the Company will cease deferral to Account 108.0013 and reclass the cumulative deferral to Account 108.0001. This will complete the Company's expected accounting related to implementation of FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (as codified in ASC 410, Asset Retirement and Environmental Obligations).

Regulatory Accounting Treatment and Amortization of Jurisdictional Deferrals

Q. HOW DOES THE COMPANY ACCOUNT FOR SIGNIFICANT REGULATORY DEFERRALS?

A. FASB ASC 980 requires deferral accounting when certain conditions are met. FASB ASC 980-340 requires that when incurred costs are probable of future recovery, the unrecovered costs should be capitalized (deferred) as a regulatory asset and amortized to expense when recovered in revenues. Conversely, FASB ASC 980-405 requires the recognition of a regulatory liability/provision for refund when it becomes probable that a utility will be required by a regulator to provide a refund to customers. FASB ASC 980 recognizes that a regulator can provide reasonable assurance of the existence of an asset if the regulator provides for the future recovery through cost-based rates of a currently incurred cost that would otherwise have been charged to expense. When that occurs, the regulator-created asset, or regulatory asset, must be recorded by deferring the incurred cost to be recovered in the future. The deferral as a regulatory asset of unrecovered incurred costs to be recovered in the future allows the Company to properly match such costs with the revenues, allowing recovery of such costs in the same accounting period. The matching of cost and revenue is a long-standing utility accounting concept, which produces meaningful financial statements especially for cost-based regulated operations. The Federal Energy Regulatory Commission ("FERC") amended its Uniform System of Accounts ("USofA"), incorporating FASB ASC 980 in the USofA, in its Order 390 effective January 1, 1984. As such, the Company's proposed deferral accounting is consistent with both Generally Accepted Accounting Principles ("GAAP") codified in FASB ASC 980 and the FERC USofA.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO AMORTIZE THE BIG SANDY UNIT 1 OPERATIONS RIDER DEFERRAL (SECTION V, EXHIBIT 2 W17).

A. The January 18, 2018 Order in Case No. 2017-00179 approved recovery of Big Sandy Unit 1 costs in base rates effective January 19, 2018. At the time new base rates were implemented, the Company stopped recording under-/over-recovery adjustments to the Big Sandy Unit 1 Operations Rider ("BS1OR") regulatory asset/regulatory liability balance. The final BS1OR regulatory asset balance was $2,832,717. In Case No. 2020-00174, the Company requested and was authorized to amortize $1,083,438 over 3 years (a portion of the final BS1OR regulatory asset balance), which represented a $361,146 annual expense in the cost of service. In the current case, the Company is requesting to amortize the remaining BS1OR regulatory asset balance as of December 31, 2023 of $1,749,279 over 3 years, which represents a $583,093 annual expense in the cost of service. The cost of service adjustment at Section V, Exhibit 2 W17 is increasing expense in the test year by $221,947 to adjust the test year per book expense amount of $361,146 to the requested annual expense amount of $583,093. The BS1OR regulatory asset balance and related proposed amortization expense is directly assigned to the Company's retail jurisdiction. The 3-year amortization period proposed in this case is consistent with the amortization period authorized in the prior case.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO AMORTIZE THE NERC COMPLIANCE AND CYBERSECURITY COST DEFERRAL (SECTION V, EXHIBIT 2 W24).

A. The Company is requesting to amortize the NERC Compliance and Cybersecurity cost deferral post March 31, 2020, authorized by the final order in Case No. 2020-00174, of $2,157,525 over 5 years, which represents a $431,505 annual expense in the cost of service. In addition, for the NERC Compliance and Cybersecurity cost deferral related to the period March 1, 2017 through March 31, 2020, the Company is requesting to continue the level of annual amortization expense authorized in Case No. 2020-00174 of $88,868. The cost of service adjustment at Section V, Exhibit 2 W24 is increasing expense in the test year by $444,168 to adjust the test year per book expense amount of $76,205 to the requested annual expense amount of $520,373 (composed of $431,505 related to amortization of the deferral post March 31, 2020 and $88,868 related to the amortization of the deferral for the period March 1, 2017 through March 31, 2020). The NERC Compliance and Cybersecurity cost deferral regulatory asset balance and related amortization expense is directly assigned to the Company's retail jurisdiction. The 5-year amortization period proposed in this case is consistent with the amortization period authorized in the prior cases, and it aligns with the five-year depreciable life of underlying projects.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO AMORTIZE THE FINAL DEFERRED PLANT MAINTENANCE REGULATORY LIABILITY (SECTION V, EXHIBIT 2 W48).

A. The plant maintenance cost deferral was authorized by the order dated January 18, 2018 in Case No. 2017-00179 and ceased as a result of the order dated January 13, 2021 in Case No. 2020-00174.

The cumulative plant maintenance cost deferral through March 31, 2020 was a regulatory asset of $696,194, and was authorized for recovery over a 3-year period by including an annual expense of $232,065 in the cost of service in Case No. 2020-00174. This regulatory asset will be fully collected at the approximate time new base rates are implemented as a result of this proceeding.

The plant maintenance cost deferral related to the period April 1, 2020 through January 13, 2021 is a regulatory liability of $(2,097,760). The Company is requesting to amortize this regulatory liability over 3 years, which represents a $(699,253) annual reduction (credit) in the cost of service.

The cost of service adjustment at Section V, Exhibit 2 W48 is decreasing expense in the test year by $(931,318) to adjust the test year per book expense amount of $232,065 to the requested annual expense reduction (credit) amount of $(699,253). The plant maintenance cost deferral and related proposed amortization expense is directly assigned to the Company's retail jurisdiction. The 3-year amortization period proposed in this case is consistent with the amortization period authorized in the prior case.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CERTAIN REGULATORY ASSET AMORTIZATIONS NOT RECOVERED THROUGH BASE RATES (SECTION V, EXHIBIT 2 W59).

A. This adjustment removes certain regulatory asset amortizations from the cost of service that should not be recovered through base rates going forward, decreasing test year expense by $(2,542,980). These regulatory assets and related amortization expenses are directly assigned to the Company's retail jurisdiction.

<u>Other O&M Adjustments</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR INTEREST EXPENSE ASSOCIATED WITH CUSTOMER DEPOSITS (SECTION V, EXHIBIT 2 W15).

A. During 2022, the interest rate paid by Kentucky Power pursuant to KRS 278.460 on customer deposits was 0.12%. Test year customer deposit interest expense was $452,405. On December 9, 2022, the Commission announced that the 2023 interest rate applicable to customer deposits would be increased to 4.34%. Consistent with the treatment of customer deposit interest expense in prior rate cases, Kentucky Power proposes to increase test year customer deposit interest expense by $1,258,220 to $1,710,625 in order to reflect the increase in the applicable rate from 0.12% to 4.34%.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO NORMALIZE STORM DAMAGE EXPENSE (SECTION V, EXHIBIT 2 W16).

A. This adjustment decreases test year distribution and transmission major and non-major storm project expense by $(6,319,995) to establish a total level of major and non-major storm project expense in base rates of $1,013,489 for distribution (Kentucky retail jurisdictional amount of $1,012,476) and $89,872 for transmission (Kentucky retail jurisdictional amount of $88,524). As discussed by Company Witness West, the Company has determined to request a level of storm expense in base rates similar to what was approved in its last base case (Case No. 2020-00174) in lieu of requesting an updated level of expense reflective of recent storm experience (i.e., current 3-year average).

Q. PLEASE EXPLAIN THE ADJUSTMENT TO ANNUALIZE LEASE EXPENSE (SECTION V, EXHIBIT 2 W20).

A. This adjustment decreases O&M expense to reflect the annualized lease expense for the Company at the test year-end. Specifically, annualized March 2023 lease expenses of $33,897 were compared to test year lease expenses of $443,758, resulting in a calculated decrease of $(409,861). After applying the corresponding retail allocation factors, the retail jurisdictional share of the cost of service decrease for lease expenses is $(406,497). Please refer to the testimony of Company Witness Phillips for discussion of the Company's decisions to buyout certain leases.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO NORMALIZE BAD DEBT EXPENSE (SECTION V, EXHIBIT 2 W26).

A. This adjustment normalizes bad debt expense related to customer accounts receivable (Kentucky retail jurisdiction O&M increase of $630,228) and miscellaneous accounts receivable (Kentucky retail jurisdiction O&M decrease of $(482,437)), resulting in a net Kentucky retail jurisdiction O&M increase of $147,791.

<u>Customer Accounts Receivable</u>

Prior to the first quarter of 2022, the Company sold, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit under an affiliated receivables sales arrangement. Under the arrangement, the Company was charged a fee for each sale based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience from previous purchases of the Company's customer accounts receivable. The Company recorded these expenses in FERC Accounts 426.5009 and 426.5010 and included them in the Kentucky retail jurisdiction revenue requirement. As discussed by Company Witness West, the Company terminated selling accounts receivable to AEP Credit in the first quarter of 2022.

As a result of the termination, KPCo recorded an allowance for uncollectible accounts on its balance sheet and recognized corresponding bad debt expense in FERC Account 904.0000, for those receivables no longer sold to AEP Credit. The Company's bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable.

Therefore, in order to calculate a normalized level of test year bad debt expense to include in the Kentucky retail jurisdiction revenue requirement, I am supporting an adjustment to remove test year activity in FERC Accounts 426.5009 and 426.5010 (Kentucky retail jurisdiction O&M increase of $232,198) and annualize the activity in FERC Account 904.0000 based on the average of actual monthly activity for June 2022 - March 2023 (Kentucky retail jurisdiction O&M increase of $398,030). Together, these two items result in a total Kentucky retail jurisdiction O&M increase of $630,228 to normalize bad debt expense related to customer accounts receivable.

<u>Miscellaneous Accounts Receivable</u>

A non-recurring bad debt expense of $472,081 was removed from the test year. In addition, bad debt expense related to the Company's home warranty program of $10,363 was removed from the test year. Together, these two items result in a total Kentucky retail jurisdiction O&M decrease of $(482,437) to normalize bad debt expense related to miscellaneous accounts receivable.

Q. PLEASE EXPLAIN THE AFUDC OFFSET ADJUSTMENT (SECTION V, EXHIBIT 2 W38).

A. The March 31, 2023 balance of Construction Work In Progress ("CWIP") was used in the determination of rate base. Consistent with prior Commission practice for the Company, an Allowance for Funds Used During Construction ("AFUDC") "offset" adjustment is being made to record AFUDC above the line. The CWIP balance was $144,447,404 on March 31, 2023, of which $18,634,010 is not subject to AFUDC. The remaining balance of $125,813,394 is subject to AFUDC. Using the requested overall return of 6.930%, annualized AFUDC is $8,718,868. The AFUDC booked during the test year was $3,727,299 requiring an adjustment to increase the AFUDC offset by $4,991,569. The retail jurisdictional amount of the AFUDC offset increase is $4,921,688.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE JOINT USE POLE RENTAL REVENUE AND O&M EXPENSE ACTIVITY RELATED TO A PRIOR PERIOD (SECTION V, EXHIBIT 2 W44).

A. An adjustment to joint use pole rental revenue and expense was recorded in the test year that relates to a prior period. This cost of service adjustment increases test year revenue and expense to remove this prior period adjustment from the test year. The retail jurisdictional shares of the revenue (Account 454) and O&M expense (Account 589) increases are $4,266 and $9,065, respectively.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE NON-ONGOING O&M EXPENSE RELATED TO THE COVID-19 PANDEMIC (SECTION V, EXHIBIT 2 W45).

A. The Company established a project in its general ledger system to track expenses related to its response to the COVID-19 pandemic. During the test year, $84,376 was recorded to this project. This cost of service adjustment decreases test year O&M expense by $(84,376), removing this expense from the test year. The retail jurisdictional share of the expense reduction is $(83,222).

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE INSURANCE PROCEEDS RELATED TO A PRIOR PERIOD (SECTION V, EXHIBIT 2 W46).

A. During the test year, the Company recorded insurance proceeds from an insurance claim related to a prior period, resulting in decreased O&M expense. This cost of service adjustment removes the insurance proceeds (net of expense related to the insured loss recorded during the test year) to reflect O&M expense at a going level. The retail jurisdictional share of the resulting expense increase is $50,544 in Account 5130.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE ROCKPORT UNIT POWER AGREEMENT NON-FUEL EXPENSE, NET OF TEST YEAR DEFERRAL (SECTION V, EXHIBIT 2 W47).

A. The Company's Rockport Unit Power Agreement ("UPA"), and corresponding deferral of related non-fuel, non-environmental expenses authorized in Case No. 2017-00179, ended in December 2022. This adjustment removes test year Rockport UPA non-fuel, non-environmental expenses of $(46,035,951), and related test year expense deferral of $10,322,581, as these expenses are not ongoing, resulting in a net $(35,713,370) reduction in the cost of service. This adjustment is directly assigned to the Company's retail jurisdiction.

Once new base rates are established that exclude Rockport UPA non-fuel, non-environmental expense, the Company will cease crediting customers through Tariff P.P.A., in accordance with Case Nos. 2017-00179 and 2022-00283.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO NORMALIZE NON-F.A.C. ELIGIBLE PURCHASED POWER EXPENSE (SECTION V, EXHIBIT 2 W57).

A. The purpose of this adjustment is to reflect a normalized level of Non-F.A.C. eligible purchased power expense in the test year. Within the Company's Tariff Fuel Adjustment Clause ("F.A.C."), the F.A.C. Purchase Power Limitation caps the amount of purchased power expense to be recovered in the Company's monthly F.A.C. surcharge. Total Non-F.A.C. eligible purchased power expense recorded in the test year ended March 31, 2023 was $14,720,086, and is composed of $11,519,695 related to Winter Storm Elliott incurred in December 2022 and $3,200,390 in other test year expenses. Non-F.A.C. eligible purchased power expense recorded in the twelve months ended March 31, 2022 and March 31, 2021 was $1,656,284 and $99,134, respectively.

This adjustment decreases test year expense by $(13,068,150) to establish a normalized level of Non-F.A.C. eligible purchased power expense in the test year of $1,651,936, based on a three-year average of actual Non-F.A.C. eligible purchased power expense, excluding expense related to Winter Storm Elliott. This adjustment is directly assigned to the Company's retail jurisdiction. Company Witness Vaughan supports the prudence of the Company's Non-F.A.C. eligible purchased power expenses.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO RECOVER ACTUAL, INCREMENTAL NON-F.A.C. ELIGIBLE PURCHASED POWER COSTS SINCE THE COMPANY'S LAST BASE CASE, EXCLUDING COSTS RELATED TO WINTER STORM ELLIOTT (SECTION V, EXHIBIT 2 W58).

A. I have been advised that purchased power costs that exceed the amount allowed for recovery through the F.A.C. are recoverable in base rates[3]. Excluding expense related to Winter Storm Elliott , the Company's actual Non-F.A.C. eligible purchased power expenses from the test year end in the Company's last base case (March 31, 2020) to the test year end in this case (March 31, 2023), in excess of the level of Non-F.A.C. eligible purchased power expenses included in base rates, was $4,020,055. This adjustment proposes to recover these costs over a 3-year period (the same period over which these costs were incurred) by including an expense of $1,340,018 in the annual base rate revenue requirement. This adjustment is directly assigned to the Company's retail jurisdiction. Company Witness Vaughan supports the prudence of the Company's Non-F.A.C. eligible purchased power expenses. Company Witness West addresses the Company's request regarding Non-F.A.C. eligible purchased power expense related to Winter Storm Elliott.

[3] Order at 5, *An Examination By The Public Service Commission Of The Fuel Adjustment Clause Of American Electric Power Company From May 1, 2001 To October 31, 2001*, Case No. 2000-00495-B (Ky. P.S.C. May 2, 2002).

VI. RATE BASE ADJUSTMENTS

Q. ARE YOU SPONSORING ANY ADJUSTMENTS TO RATE BASE?

A. Yes. The table below identifies the adjustments to rate base that I am sponsoring. The details supporting the calculations of these adjustments are included on the referenced pages of Exhibit 2 to Section V of the Application.

Adjustment Description	Reference in Section V, Exhibit 2
Mitchell Coal Stock Adjustment (Coal Inventory Adjustment)	W39
Remove NERC Compliance and Cybersecurity Net Plant from Rate Base	W53 Pg. 1 of 2
Cash Working Capital	W61

Q. PLEASE EXPLAIN THE MITCHELL PLANT COAL STOCK ADJUSTMENT TO RATE BASE (SECTION V, EXHIBIT 2 W39).

A. The coal inventory targets at the Mitchell Plant are separately developed for the low and high sulfur coal piles.

At March 31, 2023, the Mitchell Plant had 183,777 tons (Kentucky Power's 50% share) of low sulfur coal on hand at an average cost of $132.52 per ton, and a total value of $24,353,263. The target low sulfur coal inventory is 93,905 tons (Kentucky Power's 50% share). Thus, the difference between the March 31, 2023 low sulfur coal inventory and the target low sulfur coal inventory yields a downward adjustment of (89,872) tons at a March 31, 2023 value of $(11,909,402).

At March 31, 2023, the Mitchell Plant had 257,556 tons (Kentucky Power's 50% share) of high sulfur coal on hand at an average cost of $55.75 per ton and a total value of $14,358,133. The target inventory level for high sulfur coal is 174,825 tons (Kentucky Power's 50% share). Thus, the difference between the March 31, 2023 high sulfur coal inventory and the target high sulfur coal inventory yields a downward adjustment of (82,731) tons at a March 31, 2023 value of $(4,612,059).

The total adjustment (of both low and high sulfur coal), on a jurisdictional basis, is a reduction to rate base of $(16,290,160) based upon the March 31, 2023 value.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE NERC COMPLIANCE AND CYBERSECURITY INVESTMENT FROM RATE BASE (SECTION V, EXHIBIT 2 W53 PG. 1 of 2).

A. Beginning with Case No. 2014-00589, the Commission approved the deferral of certain NERC Compliance and Cybersecurity costs. Because the related intangible plant investment is earning a Weighted Average Cost of Capital ("WACC") return through the approved deferral mechanism, the Company is removing the related net intangible plant balance of $1,868,501 as of March 31, 2023 from rate base[4]. This rate base adjustment is directly assigned to the Company's retail jurisdiction.

Q. PLEASE DESCRIBE THE ALLOWANCE FOR CASH WORKING CAPITAL INCLUDED IN THE COMPANY'S RATE BASE (SECTION V, EXHIBIT 2 W61).

A. This adjustment calculates a Cash Working Capital ("CWC") allowance of $7,686,462 for the test year ended March 31, 2023, which increases the Company's rate base and

[4] The related NERC Compliance and Cybersecurity Regulatory Assets were excluded from per books rate base; therefore, it was not necessary to propose a proforma adjustment to remove these regulatory assets from rate base.

resulting revenue requirement. The expense lead and revenue lag days used in the computation of this adjustment were provided to me by Company Witness Adams, sponsor of Kentucky Power's lead-lag study. The net lead-lag days from the lead-lag study are multiplied by the proforma average daily expenses associated with the Kentucky retail jurisdiction cost-of-service components that require cash payments. The "Working Funds and Other" line item included in the adjustment is composed of the test year average cash-in-bank balance and expense leads related to pass-through taxes, as recommended by Company Witness Adams. The result is the Kentucky retail jurisdiction CWC allowance reflected by the Company in this filing.

VII. CAPITALIZATION ADJUSTMENTS

Q. ARE YOU SPONSORING ANY ADJUSTMENTS TO THE COMPANY'S CAPITALIZATION CALCULATION?

A. Yes. The table below identifies the adjustments to the Company's capitalization calculation that I am sponsoring. The details supporting the calculations of these adjustments are included on the referenced pages of Exhibit 2 to Section V of the Application. I provided these adjustments to Company Witness Walsh to incorporate in Section V, Schedule 3, Kentucky Power Company Capitalization for the test year ended March 31, 2023. As discussed by Company Witness Walsh, capitalization is being presented on Section V, Schedule 3 for informational purposes only, as rate base is being used to compute the Company's revenue requirement pursuant to the Commission's orders in Case No. 2020-00174.

Adjustment Description	Reference in Section V, Exhibit 2
Mitchell Coal Stock Adjustment (Coal Inventory Adjustment)	W39
Remove Big Sandy Unit 2 from Capitalization	W40
Remove NERC Compliance and Cybersecurity Investment from Capitalization	W53 Pg. 2 of 2
Remove Rockport Deferral from Capitalization	W60

Q. PLEASE EXPLAIN THE MITCHELL PLANT COAL STOCK ADJUSTMENT TO CAPITALIZATION (SECTION V, EXHIBIT 2 W39 AND SCHEDULE 3, COLUMN 11).

A. As discussed in the context of adjustments to rate base above, the coal inventory targets at the Mitchell Plant are separately developed for the low and high sulfur coal piles. The total adjustment (of both low and high sulfur coal), on a jurisdictional basis, is a reduction to capitalization of $(16,290,160) based upon the March 31, 2023 value.

I have been advised that the AEP System Money Pool borrows large sums of money through the issuance of short-term commercial paper in order to meet the working capital needs of AEP System Money Pool members, including Kentucky Power. Variation of the Company's actual coal inventory balance from its target coal inventory balance is a component of the Company's working capital and as such is initially financed with short-term debt; therefore, the adjustment to reduce coal inventory reflected in capitalization was applied to the short-term debt balance. I provided this adjustment to Company Witness Walsh.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE BIG SANDY UNIT 2 FROM CAPITALIZATION (SECTION V, EXHIBIT 2 W40 AND SCHEDULE 3, COLUMN 5).

A. Big Sandy Unit 2 coal assets are recovered exclusively through the Company's Tariff D.R. and therefore should be removed from capitalization[5]. In addition, Tariff D.R. rate base reflects the amortization of related unprotected accumulated deferred income taxes, as ordered by the Commission in Case Nos. 2018-00035 and 2020-00174.

As shown in Section V, Exhibit 2 W40, I provided Company Witness Walsh with a capitalization adjustment of $(222,464,455), which removes the total Company Big Sandy Unit 2 regulatory asset balance of $290,356,472, net of related accumulated deferred income taxes and unprotected excess deferred income taxes of $(67,892,018). After applying corresponding retail allocation factors to this adjustment, the retail jurisdictional amount of the capitalization adjustment is $(218,361,636).

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE NERC COMPLIANCE AND CYBERSECURITY INVESTMENT FROM CAPITALIZATION (SECTION V, EXHIBIT 2 W53 Pg. 2 of 2 AND SCHEDULE 3, COLUMN 9).

A. As discussed in the context of adjustments to rate base above, beginning with Case No. 2014-00589, the Commission approved the deferral of certain NERC Compliance and Cybersecurity costs. Because the related intangible plant investment is earning a WACC return through the approved deferral mechanism, the Company is removing the related intangible plant and regulatory asset balances from capitalization. As shown in Section V,

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[5] These regulatory assets were excluded from per books rate base; therefore, it was not necessary to propose a proforma adjustment to rate base.

Exhibit 2 W53 Pg. 2 of 2, I provided Company Witness Walsh with an adjustment to capitalization of $(3,161,736) to reflect the Company's related net intangible plant investment balance of $1,868,501 and regulatory asset balance of $2,133,697 as of March 31, 2023, net of related accumulated deferred income taxes of $(840,462). The NERC Compliance and Cybersecurity capitalization adjustment is directly assigned to the Company's retail jurisdiction.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE THE ROCKPORT DEFERRAL FROM CAPITALIZATION (SECTION V, EXHIBIT 2 W60 AND SCHEDULE 3, COLUMN 10).

A. In Case No. 2017-00179, the Commission authorized the deferral of $50 million of Rockport Plant UPA non-fuel, non-environmental expenses. Because the Rockport deferral is earning a WACC return through the approved deferral mechanism, the Company is removing the total deferral from capitalization.

As shown in Section V, Exhibit 2 W60, I provided Company Witness Walsh with a capitalization adjustment of $(40,020,354), which removes the total Company Rockport deferral regulatory asset balance of $50,658,676[6], net of related accumulated deferred income taxes of $(10,638,322). The Rockport deferral is directly assigned to the Company's retail jurisdiction.

[6] These regulatory assets were excluded from per books rate base; therefore, it was not necessary to propose a proforma adjustment to rate base.

Q. ARE YOU SPONSORING ANY OTHER ADJUSTMENTS TO CAPITALIZATION PRESENTED ON SECTION V, SCHEDULE 3?

A. Yes, consistent with prior practice, the Franklin Realty Company investment, recorded in FERC Account 124.0029, was removed from the Company's capitalization (Section V, Schedule 3, Column 12). In addition, consistent with prior practice, the non-utility property investment recorded in FERC Account 121 was removed from the Company's capitalization (Section V, Schedule 3, Column 13).

VIII. <u>REQUESTS FOR DEFERRAL ACCOUNTING AUTHORITY RELATED TO PROPOSED RIDERS</u>

Q. IF THE PROPOSED DISTRIBUTION RELIABILITY RIDER ("DRR") IS APPROVED, WOULD A REGULATORY ASSET OR REGULATORY LIABILITY BE CREATED TO ACCOUNT FOR TEMPORARY DIFFERENCES BETWEEN DRR REVENUES AND ACTUAL DRR PROJECT COSTS ELIGIBLE FOR RECOVERY THROUGH THE DRR?

A. Yes. The Company would defer the cumulative monthly difference between DRR revenues and actual incurred DRR project costs eligible for recovery through the DRR, as a regulatory asset or regulatory liability on the books and records of the Company. This deferral -- a regulatory liability or regulatory asset which represents "over-under" recoveries -- is a timing difference between eligible costs incurred for DRR projects and DRR revenues and is intended to be zero as of the end of the DRR. The Company requests specific provisions in the final order in this proceeding authorizing the creation of this regulatory asset or regulatory liability for DRR over-under recoveries.

Q. IF THE PROPOSED CHANGES TO THE FEDERAL TAX CHANGE ("FTC") RIDER ARE APPROVED, WOULD A REGULATORY ASSET OR REGULATORY LIABILITY BE CREATED TO ACCOUNT FOR TEMPORARY DIFFERENCES BETWEEN FTC REVENUES/(REFUNDS) AND ACTUAL COSTS/(BENEFITS) ELIGIBLE FOR TRACKING THROUGH THE FTC RIDER?

A. Yes. The Company would defer the cumulative monthly difference between FTC revenues/(refunds) and actual incurred FTC costs/(benefits), as a regulatory asset or regulatory liability on the books and records of the Company. This deferral -- a regulatory liability or regulatory asset which represents "over-under" recoveries -- is a timing difference between eligible tax costs/(benefits) incurred and FTC revenues/(refunds) and is intended to be zero as of the end of the FTC. The Company requests specific provisions in the final order in this proceeding authorizing the creation of this regulatory asset or regulatory liability for FTC over-under recoveries.

Q. ONCE AGAIN, CAN YOU PLEASE DESCRIBE THE BASIS FOR OVER-/UNDER-RECOVERY ACCOUNTING.

A. As discussed in Section V of my testimony, Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") 980-340-25-1 (regulatory assets) requires deferral accounting based on the existence of a regulatory asset when there is probability of recovery from customers in the future for an under-recovery of costs. ASC 980-405-25-1 (regulatory liabilities) requires deferral accounting based on the existence of a regulatory liability when a true-up to actual costs results in an over-recovery and probability of refund to customers in the future.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Heather M. Whitney, being duly sworn, deposes and says she is Director, Regulatory Accounting Services that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Heather M. Whitney

State of Ohio)
) Case No. 2023-00159
County of Franklin)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Heather M. Whitney, on 6/27/23.

Notary Public

NOTARIAL SEAL STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires Never

Notary ID Number None

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

LINDA M. SCHLESSMAN

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
LINDA M. SCHLESSMAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

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EXHIBIT LMS-2	IRS Private Letter Ruling 201438003
EXHIBIT LMS-3	IRS Private Letter Ruling 201519021
EXHIBIT LMS-4	IRS Private Letter Ruling 201534001
EXHIBIT LMS-5	IRS Private Letter Ruling 201548017
EXHIBIT LMS-6	IRS Private Letter Ruling 201709008
EXHIBIT LMS-7	IRS Private Letter Ruling 202010002
EXHIBIT LMS-8	NOLC – Total Company Calculation
EXHIBIT LMS-9	NOLC – Jurisdictional Amounts
EXHIBIT LMS-10	NOLC Deficient Taxes
EXHIBIT LMS-11	NOLC – Total Company Journal Entries

DIRECT TESTIMONY OF
LINDA M. SCHLESSMAN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Linda M. Schlessman. I am a Tax Accounting & Regulatory Support Manager for American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I have a Bachelor of Business Administration Degree in Accounting from Miami University and am a Certified Public Accountant in the State of Ohio. I have over 15 years of tax experience. I joined AEPSC in October of 2018 as a Tax Manager and was promoted to my current role in November of 2021. Prior to that time, I held positions in both public accounting and the private sector. My previous employers include GBQ Partners LLC, HBD Industries Inc., and L Brands Inc.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I filed testimony in rate proceedings before the Oklahoma Corporation Commission in Case No. PUD 2022-000093 and before the Arkansas Public Service Commission in Case No. 23-012-FR.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to calculate the Gross Revenue Conversion Factor ("GRCF"); to present and support certain adjustments to the jurisdictional federal, state, and local income taxes to which Kentucky Power is subject; to support the tax effects of certain fixed, known, and measurable ratemaking adjustments for the test year ended March 31, 2023; and to support certain modifications to the Company's existing Federal Tax Cut Tariff ("Tariff F.T.C.").

Q. WHAT ARE THE IMPACTS OF THE COMPANY'S TAX ADJUSTMENTS IN THIS PROCEEDING?

A. Figure LMS-1 below summarizes the proposed impacts addressed in my testimony.

Figure LMS-1

Adjustment	Expense or Rate Base	Rate Base Gross Amount Increase/ (Decrease)	After Tax Rate of Return	Amount Increase/ (Decrease) in Net Income	Section V Reference
Annualization of Property Taxes	Expense	N/A	N/A	2,587,239	Exhibit 2, #49
Sales and Use Tax	Expense	N/A	N/A	(65,715)	Exhibit 2, #50
State Business and Occupation Tax	Expense	N/A	N/A	4,231	Exhibit 2, #51
Interest Synchronization Adjustment	Expense	N/A	N/A	1,839,129	Exhibit 2, #54
Cost of Removal Regulatory Asset Amortization	Expense	N/A	N/A	1,667,845	Exhibit 2, #55
Net Operating Loss Carryforward - Deferred Tax Asset	Rate Base	41,506,654	6.93%	2,876,411	Exhibit 3, #63
Net Operating Loss Carryforward - Regulatory Liability	Rate Base	10,300,444	6.93%	713,821	Exhibit 3, #63
Excess Unprotected Amortization	Rate Base	19,673,877	6.93%	1,363,400	Exhibit 3, #63

Q. WHAT ARE THE INITIAL AMOUNTS PROPOSED TO BE INCLUDED IN THE REVISED TARIFF F.T.C.?

A. Figure LMS-2 below summarizes the proposals that will be included in the Tariff F.T.C., which I will discuss further below.

Figure LMS-2

Adjustment	Expense or Rate Base	Rate Base Gross Amount Increase/ (Decrease)	After Tax Rate of Return	Amount Increase/ (Decrease) in Net Income
Excess Protected Amortization	Expense	N/A	N/A	(1,678,164)
Corporate Alternative Minimum Tax	Expense	N/A	N/A	-

IV. GROSS REVENUE CONVERSION FACTOR

Q. PLEASE DESCRIBE THE GROSS REVENUE CONVERSION FACTOR.

A. The GRCF is the factor necessary to determine the incremental amount of gross revenue required to generate an additional dollar of operating income after accounting for the effects of uncollectible accounts, commission assessment fees, and state and federal income taxes.

Q. HOW WAS THE GRCF RATE DETERMINED?

A. The methodology used in this case was also utilized in the Company's prior base rate cases. The uncollectible accounts rate and the KRS 278.130 assessment rate were provided to me by Kentucky Power; the state and federal income tax rates and apportionment factors are based on the most recent income tax return information that also is currently being used in the monthly closing accrual process. Please see Section V, Exhibit 3, Workpaper S-2, Page 2.

V. <u>JURISDICTIONAL STATE AND FEDERAL INCOME TAXES</u>

Q. PLEASE DESCRIBE THE COMPUTATION OF JURISDICTIONAL STATE AND CURRENT FEDERAL INCOME TAXES.

A. The computation of jurisdictional Current Federal Income Tax is accomplished by first allocating Pre-Tax Book Income and the various book-to-tax adjustments used in the determination of the Company's total separate federal taxable income to Kentucky Power's retail customers, and applying the statutory federal income tax rate of 21%, as shown in Section V, Exhibit 3. The computation of jurisdictional Deferred Federal income tax is accomplished by applying the appropriate federal income tax rate to the allocated normalized timing differences, as shown in Section V, Exhibit 3, and by amortizing the allocated balances of the embedded Deferred Federal income taxes balances over the appropriate remaining lives. State income tax expense is calculated on the same basis as the federal income tax expense as shown in Section V, Exhibit 3. Company Witness Walsh prepared the jurisdictional allocation factors.

Q. WERE DEFERRED TAXES ALLOCATED TO THE KENTUCKY RETAIL JURISDICTION?

A. Yes. Each component was allocated to the Kentucky retail jurisdiction as shown in Section V, Exhibit 3.

VI. <u>RATEMAKING ADJUSTMENTS</u>

Q. WHICH RATEMAKING ADJUSTMENTS ARE YOU SPONSORING?

A. I am sponsoring the ratemaking adjustments in Section V, Exhibit 2 related to the following:

1. Annualization of Property Taxes
2. Sales and Use Tax
3. State Business and Occupation Tax
4. Interest Synchronization Adjustment
5. Cost of Removal Regulatory Asset Amortization and Normalization
6. Net Operating Loss Carryforward Deferred Tax Asset and Adjustment to Excess Protected Amortization
7. Removing Kentucky Excess Accumulated Deferred Income Tax ("ADFIT") related to Tariff F.T.C.
8. Corporate Alternative Minimum Tax Adjustment

These adjustments are necessary to reflect an adjusted test year level of tax expense representative of ongoing operations. In addition, I have reviewed each of the ratemaking adjustments proposed by other Company witnesses and determined the proper income tax consequences as shown on Section V, Schedule 2.

VII. NON-INCOME TAX AND INTEREST SYNCHRONIZATION ADJUSTMENTS

Q. PLEASE DESCRIBE THE ANNUALIZATION OF PROPERTY TAX ADJUSTMENT.

A. Adjustment 49 of Section V, Exhibit 2 calculates the difference between the property taxes that were estimated and actually paid.

Q. PLEASE DESCRIBE THE SALES AND USE TAX ADJUSTMENT.

A. Adjustment 50 of Section V, Exhibit 2 adjusts the Sales and Use Tax Expense to remove an out-of-period adjustment related to the settlement of a Sales and Use Tax Audit that was recorded during the test period.

Q. PLEASE DESCRIBE THE STATE BUSINESS AND OCCUPATION TAX ADJUSTMENT.

A. Adjustment 51 of Section V, Exhibit 2 adjusts the State Business and Occupation Tax Expense to remove an out-of-period adjustment that was recorded during the test period.

Q. PLEASE DESCRIBE THE INTEREST SYNCHRONIZATION ADJUSTMENT.

A. Adjustment 54 of Section V, Exhibit 2 synchronizes the capital costs and capital structure included by the Company in this filing with the federal and state income taxes included in the test period cost of service and the interest expense tax deduction that will result. The adjustment resulted in an increase to state income tax of $368,966 and an increase to federal income tax of $1,470,163 for a total increase to expenses of $1,839,129.

VIII. COST OF REMOVAL

Q. WHAT ARE REMOVAL COSTS?

A. A removal cost is an amount that a utility expects to incur to remove an asset at the end of its life based on the price levels in effect at the time it is removed.

Q. HOW HAVE REMOVAL COSTS BEEN TREATED FOR RATEMAKING PURPOSES?

A. For ratemaking purposes, cost of removal ("COR") is treated similarly to the overall book depreciation expense in the Company's cost of service. This cost is recalculated periodically, and recovery is reflected in rates over a period that approximates the life of the plant. While there is not exact matching, this approach seeks to recover the cost of the plant through charges to customers benefitting from the use of an asset.

Q. HOW ARE REMOVAL COSTS ACCOUNTED FOR ON THE COMPANY'S FINANCIAL STATEMENTS?

A. As previously discussed, the removal costs are included in the overall book depreciation. On the income statement, the book depreciation for removal costs is recorded to account 403 under FERC's Uniform System of Accounts ("USoA"). On the balance sheet, the accumulated accrual of removal costs is recorded to account 108 and are included in the accumulated book depreciation.

Q. IS THE TIMING OF THE RECOGNITION OF REMOVAL COSTS THE SAME FOR FEDERAL INCOME TAX AND FINANCIAL STATEMENT PURPOSES?

A. No. For financial statement purposes, removal costs are recognized over the life of an asset while for tax purposes they are recognized at the time costs are actually incurred to remove an asset. COR is defined as an allowable deduction under IRC §162 rather than IRC §168. IRC §162 defines general trade or business expenses while IRC §168 defines the method of depreciation for property. Therefore, rather than recognizing removal costs over the life of an asset, the COR is not recognized for tax purposes until the costs are actually incurred at the end of the asset's life.

Q. HOW IS THIS DIFFERENCE IN THE RECOGNITION OF COR EXPENSE ACCOUNTED FOR?

A. Because the financial statements have recognized an expense for COR prior to the allowable recognition for tax purposes, the book depreciation expense is excluded from the calculation of taxable income, and a deferred tax asset ("DTA") is recorded. This DTA represents the future tax benefit that will be received when the asset is retired and COR is incurred.

Q. WHAT IS THE COMPANY PROPOSING REGARDING COR IN THIS PROCEEDING?

A. The Company is proposing to treat the timing difference for COR under the normalized method of tax accounting and recover the regulatory asset for COR. Treating the timing difference under the normalized method would align the origin and reversal of the timing difference and provide an equitable recovery to rate payers going forward.

Adjustment 55 of Section V, Exhibit 2 amortizes the regulatory asset balance of $33,356,902 related to COR over a 20-year period and reduces the adjustment to income tax expense for flow-through of COR going forward to zero in order to align the origination and reversal of the timing difference going forward. The annual amount of included in cost of service would be $1,667,845.

Q. WHAT IS MEANT BY USING A NORMALIZED METHOD OF TAX ACCOUNTING?

A. Normalization is a method of tax accounting in which the taxes reflected within an entity's income statement for a given period are matched with the associated revenues and expenses. This methodology, also known as "deferred income tax" accounting, is required for financial reporting under Generally Accepted Accounting Principles ("GAAP") (Financial Accounting Standards Board Accounting Standards Codification Topic 740 (ASC 740), formerly Statement of Financial Accounting Standards No. 109 (SFAS 109)).

Q. CAN YOU PROVIDE AN EXAMPLE OF NORMALIZED TAX ACCOUNTING?

A. Yes. As an example, in the early years of an asset's life, accelerated tax depreciation often exceeds depreciation expense reported in the financial statements allowing for the deferral of income taxes due to the taxing authority. In such an instance, the taxes deferred are debited to a deferred tax expense account with a corresponding credit to a deferred tax liability.

In later years, when the book-to-tax difference reverses, the increase in tax due is mitigated by also reversing the deferred tax liability through a corresponding credit to deferred income tax expense.

Figure LMS-3

Example of Normalized Accounting

	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Revenues	1,000	1,000	1,000	1,000	1,000	5,000
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(2,500)
Book Depreciation	(100)	(100)	(100)	(100)	(100)	(500)
Pre-tax Book Income (PTBI)	400	400	400	400	400	2,000
Tax Depreciation	(250)	(100)	(75)	(50)	(25)	(500)
Federal Taxable Income	250	400	425	450	475	2,000
Federal Current Tax Expense	53	84	89	95	100	420
Federal Deferred Tax Expense	32	-	(5)	(11)	(16)	-
Total Federal Tax Expense	84	84	84	84	84	420
Book/ Tax Depreciation Difference	(150)	-	25	50	75	-
DTA/ (DTL)	(32)	(32)	(26)	(16)	-	

Q. WHAT IS THE ALTERNATIVE TO NORMALIZED ACCOUNTING?

A. The alternative to a normalized method of tax accounting is referred to as "flow-through" accounting. A flow-through approach bases income tax expense reported within the financial statements on the tax liability as reported on the tax return, as opposed to that determined in accordance with ASC 740. The total amount of income tax expense is the same under both normalized and flow-through approaches – the difference is simply timing.

The term "normalization" evolved with respect to utilities, because income taxes computed on a normalized basis caused net income to appear "normal", in contrast to an approach based on the cash liability reported on the tax return.

Q. HAS NORMALIZED TAX ACCOUNTING ALWAYS BEEN THE METHOD OF ACCOUNTING UTILIZED BY THE COMPANY?

A. No. Prior to the issuance of SFAS 109 by the Financial Accounting Standards Board in February 1992, non-property related deferred tax timing differences could be treated as flow-through. Property timing differences have historically been treated as normalized mainly due to the Tax Reform Act of 1969 permitting utilities the right to make an election to abandon flow-through treatment of post 1969 utility property.[1]

Q. WHAT IS SFAS 109?

A. SFAS 109 required an asset and liability approach for the financial reporting for income taxes, i.e. a normalized method of accounting. One of the objectives of SFAS 109 was to recognize deferred tax liabilities and assets for the future tax consequences of items that have been recognized on a company's financial statements or tax returns.

SFAS 109 also provided guidance to utilities for book tax timing differences that were previously treated as flowthrough. Paragraph 29 addressed accounting for income taxes by regulated utilities and specifically required recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate. Additionally, if the regulated utility is allowed to recover from or return to customers the future increase or decrease in tax increase payable for tax benefits flowed through to customers, a regulatory asset or liability is recognized for that probable future revenue or reduction in future revenues.

Q. HOW DID THE COMPANY TRANSITION TO A NORMALIZED METHOD OF TAX ACCOUNTING AS REQUIRED BY SFAS 109?

A. AEP operating companies, including Kentucky Power Company, adopted SFAS 109[2] effective January 1, 1993. All timing differences treated as flow-through

[1] Tax Reform Act of 1969, §441, 26 U. S. C. §167 (1)

before transitioning to normalized treatment continue to unwind utilizing a flow-through methodology as approved by SFAS 109. This results in an increase to tax expense, reflective of tax expense due that a tax benefit was received for previously. All timing differences originating after the transition were accounted for on a normalized basis except for the COR deduction, which continued to be accounted for on a flowthrough basis.

Q. HAS THE COMMISSION ADDRESSED NORMALIZATION IN THE RATEMAKING PROCESS?

A. Yes. The Commission has addressed normalization in *Re Louisville Gas and Elec. Co*., 2006-00457, 2006 WL 4590816 (Dec. 11, 2006) noting that the Tax Reform Act of 1986 generally requires tax normalization for deferred income taxes, including those resulting from transactions other than accelerated depreciation and in *Re Union Light, Heat and Power Company*, 134 P.U.R.4th 139 at *3 (May 5, 1992) supporting fairness of consistent application of normalization of tax timing differences.

Q. CAN YOU EXPLAIN FLOW-THROUGH TAX ACCOUNTING AND HOW THAT DIFFERS FROM NORMALIZED TAX ACCOUNTING?

A. The flow-through method of tax accounting looks only at the amount of taxes that are payable or refundable for the current tax year and does not recognize the future benefit or detriment of temporary differences in income recorded for book purposes and income determined for tax purposes. This method treats any temporary difference as a permanent increase or decrease in the income taxes for

[2] SFAS 109 replaced with ASC 740 in 2009.

the period depending on the direction of the temporary difference. This method results in benefits and detriments being allocated among customers in different periods depending on when a temporary difference originates and reverses. For example, a timing difference that results in a deduction in Year 1 would be enjoyed by the set of customers of the company in Year 1 as a reduction to the current year taxes payable. However, if this timing difference were to reverse in Year 2, the detriment of the increase to the current year taxes payable would be borne by the set of customers of the company in Year 2, which, of course, is not necessarily the same set of customers as in Year 1. As the flow-through method only recognizes the current tax payable or receivable and ignores the impact of future tax impacts from timing differences, there is no deferred tax expense and as a result no ADIT that would be provided as a reduction to rate base.

Q. DISCUSS THE RATEMEAKING FOR INCOME TAX EXPENSE RELATED TO COR USING A NORMALIZED METHOD OF ACCOUNTING.

A. Please see Figure LMS-4 below, which assumes that $10 of the $100 book depreciation is related to COR and the asset is retired in year six.

Figure LMS-4

COR: Normalized

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total
Revenues	1,000	1,000	1,000	1,000	1,000	900	5,900
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(500)	(3,000)
Book Depreciation	(90)	(90)	(90)	(90)	(90)	-	(450)
Book Depreciation - COR	(10)	(10)	(10)	(10)	(10)	-	(50)
Pre-Tax Book Income	400	400	400	400	400	400	2,400
Tax Depreciation	(250)	(80)	(60)	(40)	(20)	-	(450)
COR Deduction	-	-	-	-	-	(50)	(50)
Federal Taxable Income	250	420	440	460	480	350	2,400
Federal Current Tax Expense	53	88	92	97	101	74	504
Federal Deferred Tax Expense	32	(4)	(8)	(13)	(17)	11	-
Total Federal Tax Expense	84	84	84	84	84	84	504
Book/Tax Timing - COR	10	10	10	10	10	(50)	-
Book/Tax Timing - Depreciation	(160)	10	30	50	70	-	-
DTA - COR	2	4	6	8	11	-	
(DTL) - Depreciation	(34)	(32)	(25)	(15)	-	-	

In the example above, the cost of service includes $84 for both current and deferred tax expense. During the life of the asset, the COR depreciation is not deductible for tax purposes and the future benefit is recorded to deferred tax expense. As such, customers are provided the benefit of the future tax deduction as the removal cost book depreciation is recognized over the life of the asset.

Q. **DISCUSS THE RATEMAKING FOR INCOME TAX EXPENSE RELATED TO COR USING A FLOW-THROUGH METHOD OF ACCOUNTING.**

A. Please see Figure LMS-5 below, which illustrates the previous example with COR being treated as flow-through.

Figure LMS-5

COR: Flow-through

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total
Revenues	1,000	1,000	1,000	1,000	1,000	900	5,900
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(500)	(3,000)
Book Depreciation	(90)	(90)	(90)	(90)	(90)	-	(450)
Book Depreciation - COR	(10)	(10)	(10)	(10)	(10)	-	(50)
Pre-Tax Book Income	400	400	400	400	400	400	2,400
Tax Depreciation	(250)	(80)	(60)	(40)	(20)	-	(450)
COR Deduction	-	-	-	-	-	(50)	(50)
Federal Taxable Income	250	420	440	460	480	350	2,400
Federal Current Tax Expense	53	88	92	97	101	74	504
Federal Deferred Tax Expense	34	(2)	(6)	(11)	(15)	-	-
Total Federal Tax Expense	86	86	86	86	86	74	504
Book/Tax Timing - COR	10	10	10	10	10	(50)	-
Book/Tax Timing - Depreciation	(160)	10	30	50	70	-	-
DTA - COR	2	4	6	8	11	-	
(DTL) - Depreciation	(34)	(32)	(25)	(15)	-	-	
Reg Liability - COR	(2)	(4)	(6)	(8)	(11)	-	

As evidenced by comparing COR: Normalized and COR: Flow-through, total tax expense over time remains $504 and only the timing of the tax expense differs.

In COR: Flow-through the cost of service includes $86 in years 1-5 and $74 for year six – the decrease in year is resulting from the tax deduction for the incurred removal costs. The deferred tax expense only relates to the book to tax timing difference related to depreciation. The cost of service included only impacts the current tax expense. Due to the tax benefit being deferred to a future period not being included in rates it is recorded as a regulatory liability.

Q. IS IT YOUR OPINION THAT THE COR DEDUCTION SHOULD BE ACCOUNTED FOR ON A NORMALIZED BASIS RATHER THAN FLOW-THROUGH PROSPECTIVELY?

A. Yes. First, as discussed above, the Commission has addressed the use of the normalized method of tax accounting. In addition, this methodology maintains inter-generational equity; that is, customers receive the income tax benefits commensurate with the expenses reflected in the cost of service.

Q. HAVE YOU PRESENTED THE COR BOOK/TAX TIMING DIFFERENCE AS NORMALIZED IN THE COST OF SERVICE IN THE PROCEEDING?

A. Yes. As part of Section V, Exhibit 3, the deferred federal income tax expense was adjusted for the COR deduction book/tax timing difference for the adjusted tax year.

Q. WHY IS THE METHOD OF TAX ACCOUNTING FOR COR BEING ADDRESSED IN THIS CASE?

A. The Company is seeking to align its ratemaking such that the taxes are normalized throughout the origination and reversal of the COR timing difference. During 2021 and 2022, the AEP System, including Kentucky Power Company, undertook a project to optimize the PowerTax fixed asset software to provide more visibility into book and tax timing differences and the ratemaking impacts of those timing differences. As such, part of the project entailed the identification of fixed asset related timing differences between book and tax that support the tax regulatory assets and liabilities on the Company’s financial statements.

It was through this analysis that an issue was identified with Kentucky Power Company's ratemaking for COR. The tax impact of a specific timing difference must either be treated as either flow-through or normalized for the origination and reversal. Either approach should yield the same tax expense over the life of the timing difference. However, through the PowerTax project, the Company identified a mismatch in the tax impact included in rates at the origination of certain COR timing differences and the reversal of those COR timing differences. The ratemaking normalized the COR timing difference at its origination, the time at which the book depreciation is recognized, and flowed through the impact at the reversal of the timing difference, the removal costs being incurred, and tax deduction recognized. This mismatch in ratemaking, normalized at origination and flowed through at reversal, results in a double benefit being provided through rates – a reduction to tax expense which follows the book depreciation and a second reduction to tax expense when the removal cost is incurred.

Q. PLEASE DEMONSTRATE THE IMPACT OF THIS DETERMINATION.

A. Please see Figure LMS-6, which illustrates the previous example with the COR deduction being treated as flow-through.

Figure LMS-6

COR: Kentucky Power Company Historical Practice

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 5	Total
Revenues	1,000	1,000	1,000	1,000	1,000	900	5,900
Operating Expenses	(500)	(500)	(500)	(500)	(500)	(500)	(3,000)
Book Depreciation	(90)	(90)	(90)	(90)	(90)	-	(450)
Book Depreciation - COR	(10)	(10)	(10)	(10)	(10)	-	(50)
Pre-Tax Book Income	400	400	400	400	400	400	2,400
Tax Depreciation	(250)	(80)	(60)	(40)	(20)	-	(450)
COR Deduction	-	-	-	-	-	(50)	(50)
Federal Taxable Income	250	420	440	460	480	350	2,400
Federal Current Tax Expense	53	88	92	97	101	74	504
Federal Deferred Tax Expense	32	(4)	(8)	(13)	(17)	-	(10)
Total Federal Tax Expense	84	84	84	84	84	74	494
Book/Tax Timing - COR	10	10	10	10	10	(50)	-
Book/Tax Timing - Depreciation	(160)	10	30	50	70	-	-
DTA - COR	2	4	6	8	10	-	
(DTL) - Depreciation	(34)	(32)	(25)	(15)	-	-	
Reg Asset - COR	-	-	-	-	-	10	

In the example above, the cost of service includes $84 in years 1-5 and, similar to the COR: Normalized figure*,* provides customers the tax benefit of the COR book depreciation. In year six, however, tax expense in the cost of service reflects the flow-through impact of the COR deduction, again providing customers the tax benefit of $10. This results in a $10 regulatory asset.

Q. DOES A TAX REGULATORY ASSET RELATED TO THE ADDITIONAL BENEFIT OF REMOVAL COST EXIST ON THE COMPANY'S FINANCIAL STATEMENTS?

A. Yes. The Company has a tax regulatory asset related to the double benefit provided for COR of $33,356,902 as of the financial statement period ended March 31, 2023. The balance is part of account 1823301. The total balance of this account at March 31, 2023 was $42,331,331. If the Company's proposal to normalize the origination and reversal of the COR timing difference is approved, the tax regulatory asset balance will no longer increase. The Company's proposal ceases the double tax benefit and provides a single benefit to tax expense during the depreciation of an asset.

Q. HOW IS THE REGULATORY ASSET KNOWN?

A. In order to complete the PowerTax software project the tax regulatory asset per the financial statement had to be grouped by timing difference and entered into the system so that the reversal of the timing difference can be tracked. Kentucky Power has three timing differences which have been treated as flow-through which make up the tax regulatory asset 1) AFUDC Equity, 2) Previously flowed through Pre-1981 property, and 3) COR. The first two were known based on the past timing tax return deductions and book depreciation taken on these items. These items will reverse over time based on future book depreciation. The remaining balance is attributable to COR. However, due to the treatment of the normalization of the book depreciation portion of the timing difference will not reverse as it represents the COR incurred or deducted on the tax return.

Q. IS THE REGULATORY ASSET INCLUDED AS A COMPONENT OF ADIT OR AS AN INCREASE TO RATE BASE?

A. No. The regulatory asset and corresponding ADIT is not a part of rate base. As noted above, the Company is proposing to amortize $1,667,845 annually over a 20-year period and cease the double benefit going forward.

IX. NORMALIZATION OF NET OPERATING LOSSES

Q. WHAT IS THE COMPANY PROPOSING REGARDING NET OPERATING LOSSES IN THIS PROCEEDING?

A. The Company is proposing to include a stand-alone net operating loss carryforward ("NOLC"). This adjustment protects customers from the risk of a normalization violation.

Internal Revenue Code ("Code") requires the Company to treat its tax expense and ADIT consistently with its rate base and book depreciation. The Company calculates rate base and book depreciation on a stand-alone basis and, as such, it must also calculate taxes on stand-alone basis to reflect actual costs in rates. Because the Company calculates taxes on a stand-alone basis, the proposed NOLC methodology is consistent with the normalization requirements within the Code.

Adjustment 63 of Section V, Exhibit 2 adds the deferred tax asset of $51,807,098 related to the Company's stand-alone NOLC position and reduces the protected excess amortization, which is currently being refunded to customers through the Tariff F.T.C., by $290,867. The NOLC is also included in the Capitalization as Column 8, Section V, of Schedule 3.

Q. WHAT IS A NET OPERATING LOSS?

A. A net operating loss ("NOL") occurs when, in a given year, a taxpayer has more deductions than taxable revenues. When an NOL occurs, the Code allows the taxpayer to carry the NOL forward to subsequent years and offset otherwise taxable income produced in that future year.

Q. ARE THERE NORMALIZATION REQUIREMENTS INCLUDED WITHIN THE CODE?

A. Yes. The Code and accompanying treasury regulations provide normalization requirements, specifically in three areas: 1) Accelerated depreciation and the associated deferred tax liability that results from its use; 2) NOL Carryforwards ("NOLC") as a result of accelerated depreciation; and 3) Investment Tax Credits ("ITC").

Q. CAN YOU PLEASE DISCUSS THE NORMALIZATION REQUIREMENTS IN THE CODE AS TO ACCELERATED DEPRECIATION?

A. The Code dictates that a regulated public utility must use the normalization method of accounting to calculate tax expense on temporary differences associated with accelerated depreciation when determining rates using a cost of service/rate of return methodology. 26 U.S. Code §168(i)(9)(A) states that, in order for a public utility to be considered to be using a normalized method of accounting:

> (i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the

> same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes, and
> (ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference[3].

Q. CAN YOU PLEASE DISCUSS THE NORMALIZATION REQUIREMENTS AS THEY RELATE TO NOLC?

A. This is specifically addressed in Treasury Regulation § 1.167(*l*)-1(h)(1)(iii), which states:

> If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (l) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover (as determined under section 172) to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (l) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Although neither the Code nor the regulations specifically address the manner in which the NOL should be treated in ratemaking under the normalization rules, the IRS has addressed this issue in several private letter rulings ("PLRs"). PLRs 201436037, 21438003, 201519021, 201534001, 201548017, 201709008, and 202010002, which are attached to my testimony as Exhibits LMS-1 through LMS-7, clarify that a tax calculation with and without accelerated depreciation is

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[3] 26 U.S.C. § 168(i)(9)(A).

used to determine the amount of the NOLC ADFIT required to be normalized. To the extent that accelerated depreciation creates an NOLC, the NOLC ADFIT must be a component of rate base. This can be reflected in rate base through ADFIT using either one of two methods to adhere to the normalization rules. In the first method, the deferred tax liability that is a result of accelerated depreciation would simply be reduced by the amount of the NOLC ADFIT. In the second method, the full, deferred tax liability is included as a rate base reduction and a separate deferred tax asset in the amount of the NOLC ADFIT is included as a rate base increase. The result of both is the same: the impact on rate base includes the net balance of the ADFIT for accelerated depreciation and the ADFIT for the NOLC. The PLRs uniformly conclude that excluding the NOLC ADFIT would constitute a normalization violation.

Q. WHAT IS THE RATIONALE FOR THIS TREATMENT OF THE NOLC ADFIT?

A. When a regulated utility experiences a NOLC, the taxpayer has not yet received the benefit of the depreciation related ADFIT, i.e., there is no interest free loan from the federal government. Accordingly, the rate base reduction is deferred until the NOLC is utilized and the loan is extended.

Q. PLEASE DESCRIBE THE CONCLUSIONS IN THE PLRS MENTIONED ABOVE.

A. The PLRs mentioned above confirm that NOLC ADFIT must be included in rate base to avoid a normalization violation when the NOL is the result of accelerated tax depreciation. They describe the NOLC as a necessary reduction to the rate base impact of the deferred tax liability associated with accelerated depreciation. Further, the PLRs prescribe either one of two approaches for determining the amount of the NOLC ADFIT that must be included in rate base: a "with-and-without" or "last dollar deducted" approach. Both of these approaches look at the hypothetical taxable income of the utility without the deductions for accelerated depreciation. The extent to which an NOLC is then attributable to accelerated depreciation must be included in rate base to avoid a normalization violation. The PLRs all contain language very similar to the following:

> Because the [ADFIT] account [Account 282], the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes [(ADFIT)]…
>
> The "with or without" [or "last dollar deducted"] methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers.

Q. IS THE INCLUSION OF AN NOLC IN RATE BASE ALSO A SOUND ACCOUNTING AND REGULATORY PRACTICE?

A. Yes. The normalization treatment of an NOLC assures that the customers of a utility receive the benefit of the deferred tax payment associated with accelerated depreciation no sooner than they would be able to do so based on the operations of the utility on a stand-alone basis. This lines up the timing of customer benefits with the ability of the utility operations to provide those benefits.

Q. ARE THERE REPERCUSSIONS TO NOT FOLLOWING THE NORMALIZATION REQUIREMENTS FOR ACCELERATED DEPRECIATION?

A. Yes. A depreciation-related normalization violation results in the utility no longer being allowed to use accelerated depreciation on all property used to provide regulated service to the jurisdiction in which the violation occurred.[4] In addition, the taxes that have been deferred as a result of the prior accelerated depreciation must be paid to the federal government more quickly than they would be in the absence of the violation.

Q. WHAT IMPACT WOULD A NORMALIZATION VIOLATION HAVE ON CUSTOMERS?

A. A normalization violation would be harmful to customers as it would result in higher utility rates. As noted above, a normalization violation would prevent the utility from claiming deductions for accelerated depreciation and would result in the Company paying the IRS more rapidly for the previously deferred taxes. This would result in a lower ADIT balance which would cause the rate base for the Company to increase. As customers pay a return on rate base, any increase in rate base would directly result in higher rates. This lower ADIT would represent the reduction to a cost-free source of capital for the Company.

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[4] 26 U.S.C. § 168(f)(2).

Q. WHAT IS MEANT BY A STAND-ALONE METHOD TO CALCULATING INCOME TAXES?

A. The stand-alone methodology calculates income taxes on utility revenues and expenses that are included in the utility's revenue requirement. This approach appropriately allocates income taxes between customers and shareholders using a benefits/burdens criteria. Under this methodology, income tax expense relates to, and results from, the provision of utility service to customers. Additionally, the stand-alone income tax calculation includes an adjustment to synchronize interest. Synchronized interest represents the portion of return that is deductible for tax purposes, and it is calculated by multiplying the weighted cost of debt by rate base. Use of synchronized interest in the tax calculation effectively "synchronizes" the calculation of income tax expense with rate base and rate of return. It calculates income taxes consistent with the assumptions used to calculate rate base and the rate of return. Synchronized interest may be more or less than the actual interest deducted on the tax return.

Q. DO THE TAXES REQUESTED IN THIS CASE REPRESENT A STAND-ALONE APPROACH?

A. Yes, the tax expense and ADIT included in this case represents the tax associated only with the income and expense of the Company in providing utility service to customers. It does not include any benefits or detriments that may arise from being included in a consolidated tax return.

Q. WHY IS THE STAND-ALONE APPROACH THE PROPER METHODOLOGY TO USE IN CALCULATING INCOME TAXES FOR RATEMAKING PURPOSES?

A. The stand-alone approach includes in the cost of service only income taxes that result from the provision of utility service to customer. Income taxes requested by the Company are based on revenues and expenses included in the cost of service calculation. There are no additions to or reductions from tax expense resulting from revenues or expenses not included in the Company's request. It is neither appropriate nor equitable to increase or reduce cost of service by tax costs or benefits that are not related to the rendition of utility service to customers. The use of a stand-alone approach prevents the cross-subsidization of costs or benefits among affiliate companies. Normalization requires consistency among tax expense, book depreciation expense, rate base, and the deferred tax reserve. [5]

Q. ON WHAT BASIS DID THE COMPANY PRESENT TAXES IN ITS MOST RECENT BASE CASE?

A. In Case No. 2020-00174, the Company presented taxes on a stand-alone basis for all tax expense and ADFIT items except for NOL. The NOL presented in that case reflected adjustments to the ADIT balance for the utilization of those tax attributes as a result of the Company being a member of a consolidated group for its federal tax return.

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[5] 26 U.S.C. § 168(i)(9)(B).

Q. WHY HAS THE COMPANY PRESENTED NOL ON A STAND-ALONE BASIS FOR THIS FILING?

A. The Company has presented the NOL on a stand-alone basis because it is the proper method to calculate income taxes for ratemaking purposes for the reasons discussed above.

Prior to the preparation for this filing, the Company identified a risk that it faced if the NOL was not presented on a stand-alone basis.[6] In instances, such as this, in which a member of a consolidated group is in an NOL position as determined on a stand-alone basis and the NOL is the result of accelerated tax depreciation, there is a risk that the Company would not be adhering to the consistency requirement of the normalization rules. Tax expense included in rates is calculated only using the revenue and expenses associated with providing utility service to the Company's customers. Similarly, book depreciation is based only on the assets that are used to provide utility service to customers. If the NOL carryforward were not calculated on a stand-alone basis, then the ADIT included in rate base would reflect a reduction that is directly a result of the taxable situation of affiliate companies. This would result in a rate base that is inconsistent with tax expense and book depreciation and therefore not in compliance with the normalization rules.

[6] Company Witness Llende discussed this issue and AEP operating companies' steps to address it on rebuttal in Case No. 2021-00481.

Q. PLEASE EXPLAIN WHY THE COMPANY'S BOOKS DO NOT REFLECT THE NOL CARRYFORWARD ON A STAND-ALONE BASIS.

A. The balance reflected on the Company's books are a result of Kentucky Power's participation in a consolidated return with its parent company and affiliates (consolidated return group). As part of the consolidated return group, the Company also participates in the group's tax allocation agreement ("Agreement"). The Agreement dictates the allocation of the consolidated tax liability and tax attributes among members of the group. As a result of the Agreement, the books of the Company reflect an NOL carryforward only to the extent that the consolidated return group has a carryforward and only for the Company's allocated share of that carryforward. At the end of the test year, the consolidated return group was not expecting to have an NOL carryforward. As a result, the Company did not have an NOL carryforward on its books despite the fact that it has an NOL carryforward when calculated on a stand-alone basis.

Q. DOES THE PARTICIPATION IN THE TAX SHARING AGREEMENT MEAN THAT THE COMPANY RECEIVED PAYMENTS FOR ITS NOL CARRYFORWARDS?

A. Yes, it has. The tax sharing agreement directs companies with taxable income to remit a payment to the parent company of the consolidated return group in the amount of its tax liability. To the extent that there are companies with taxable losses, the parent company will distribute payments to those companies for the difference between the amount the parent company is required to remit to the IRS and the amount it received from taxable income companies. Through this intercompany payment process, the Company has received payments for use of its NOL carryforwards.

Q. IF THE COMPANY RECEIVED PAYMENTS FOR ITS NOL CARRYFORWARDS THEN WHY SHOULD THE STAND-ALONE NOL CARRYFOWARD BE INCLUDED IN RATE BASE?

A. The stand-alone NOL carryforward is both appropriate and necessary to include in the net ADIT reduction to rate base. First, the IRS guidance and the Code both indicate that a NOL carryforward as a result of accelerated depreciation must be included in the rate base of the utility. As discussed, the IRS has issued numerous PLR's all indicating that in order to comply with the normalization rules of the Code, the NOL carryforward must be a component of rate base. The normalization rules of the Code also specify that the assumptions for tax expense, book depreciation, and rate base must be consistent.

Figure LMS-7 below presents a simple example of a company that has accelerated tax depreciation deductions greater than its pre-tax book income which results in an NOL.

Figure LMS-7

Income Tax Expense - Per Income Statement					
Pre-Tax Net Income	10,000				
Statutory Tax Rate	21%				
Total Tax Expense	2,100				*(Tax Expense collected in customer rates)*
	Taxable Income		Tax Rate	**(DTL) / DTA**	
Pre-Tax Net Income	10,000				
Accelerated Tax Depreciation Reducing Income to Zero	(14,000)	x	21%	(2,940)	
				(2,940)	*ADIT Rate Base Reduction w/o NOL*
Taxable Income (Loss)	(4,000)				
Net Tax Loss Carry Forward	4,000	x	21%	840	
				(2,100)	*ADIT Rate Base Reduction with NOL*

In the above example, $2,100 is included in the cost of service for tax expense. The $14,000 deduction for accelerated depreciation results in a deferred tax liability of ($2,940). The company in this example has generated an NOL of $4,000 which results in a deferred tax asset of $840. As you can see in the example, when the deferred tax liability is netted with the NOL deferred tax asset the result is a rate base reduction of ($2,100). This rate base reduction is equal to the tax expense customers have paid for in the cost of service. If, however, the NOL deferred tax asset is not included as a component of rate base then rate base is reduced by ($2,940), an amount greater than the tax expense included in the cost of service. That difference between tax expense and rate base exemplifies the need for the NOL carryforward to be included as a component of rate base in order to comply with the consistency requirement of the normalization rules.

Q. CAN YOU DISCUSS THE PRO FORMA ADJUSTMENTS MADE TO REFLECT ADIT ON A STAND-ALONE ACCOUNTING BASIS?

A. Yes. A pro forma adjustment of $51,807,098 is being made to reduce the ADIT balance for a federal NOL calculated on a stand-alone basis. This adjustment represents the amount of ADIT associated with accelerated tax depreciation which has not been able to produce cash benefits to the Company on the basis of a stand-alone method as of the end of the historic test year. This adjustment reflects the ADIT associated with the taxable losses the Company has generated in excess of the taxable income it has generated and been able to offset based on the NOLC and carryback provisions of the Code. The adjustment has two components: a component to calculate the NOL deferred tax asset ("DTA") and a component to calculate the reduction to excess protected taxes, or deficient taxes, due to the establishment of the stand-alone NOL DTA.

The first component is the NOLC through the test period end generated by accelerated depreciation of $200,457,133[7] at the current tax rate of 21% and Kentucky jurisdiction allocation factor which is $41,506,654[8]. This balance will reverse as the Company incurs taxable income in the future. The second component of the NOLC is calculated by applying the change in the tax rate from 35% to 21% under TCJA to the NOLC at December 31, 2017 of $17,266,544 to arrive at the protected deficient NOL ADFIT. The amount is adjusted for the subsequent amended return movement, and the deficient amortization from January 2018 to March 2023 to arrive at a total NOLC deficient tax balance of

[7] Exhibit LMS-8.
[8] Exhibit LMS-9.

$14,641,550. The Kentucky jurisdictional amount of the $14,641,550 is $10,300,444. This balance will reverse as it is amortized through tax expense over the life of property, plant, and equipment. The second component represents the reduction to the regulatory liability for excess protected deferred taxes which was established in Case No. 2018-00035. The result of this journal entry will be a one-time credit to income tax expense and a benefit to the Company.[9] Because of the reduction to the regulatory liability for excess protected deferred taxes, the future amortization will decrease. The reduction to the regulatory liability results in a reduction to protected excess amortization of $290,867 annually for the base rates set in this proceeding.[10]

Q. HAS ANY AFFILIATE OF KENTUCKY POWER REQUESTED A PLR REGARDING THE NOLC TREATMENT IN ANY JURISDCITION?

A. Yes. Kentucky Power affiliates filed PLR requests for Texas, Oklahoma, and Indiana with the IRS in March 2022. Each PLR is identical to the tax attributes of Kentucky Power Company and the opinion applicable to the NOLC treatment proposed in this case.

[9] Exhibit LMS-11.
[10] Exhibit LMS-10.

X. EXCESS ACCUMULATED DEFERRED FEDERAL INCOME TAXES

Q. WHAT IS THE COMPANY PROPOSING REGARDING EXCESS ACCUMULATED DEFERRED FEDERAL INCOME TAXES AMORTIZATION IN THIS PROCEEDING?

A. The Company is proposing to continue to include amortization of Protected Excess ADFIT in Federal Tax Cut Tariff ("Tariff F.T.C."). Adjustment 62 of Section V, Exhibit 2 removes Kentucky Protected Excess ADFIT amortization related to the Tariff F.T.C. The test period included all Excess ADFIT for Kentucky Power Company that is included in other jurisdictions and/or in other rates that are not associated with base rates proposed in this case. These balances were removed from the case by applying a Non-Allocated factor of 0%. Finally, Kentucky Unprotected Excess ADFIT was removed from ADIT in Adjustment 63, of Section V because the amount will be fully amortized prior to rates from this case being in effect.

Q. WHAT ARE EXCESS ACCUMULATED DEFERRED FEDERAL INCOME TAXES?

A. Excess ADFIT arise not only by accelerated depreciation and bonus deprecation, but by all differences between book and tax provisions of the federal corporate income tax code that result in corporations, such as the Company, recovering, through rates, their federal corporate income tax expense at a different (initially faster) rate than they pay the associated taxes. Kentucky Power, as a regulated utility following Financial Accounting Standards Board Accounting Standards Codification 980, deferred the difference on the Company's books as a regulatory liability, and if income tax rates had remained the same, the deferral would have been reversed in later years as the Company paid its current federal corporate income tax expense at a rate that was greater than the amount the Company was recovering through rates. When the federal corporate income tax rate is reduced, as happened with the Tax Cut and Jobs Act, ("TCJA"), and all other things being equal, a portion of the deferral will never be paid and thus becomes "excess." There are two types of excess ADFIT: "protected" and "unprotected."

Q. WHAT ARE PROTECTED AND UNPROTECTED ADFIT?

A. Under the TCJA, protected and unprotected excess ADFIT are treated differently. The TCJA requires that protected excess ADFIT be amortized over "the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes." See TCJA Subtitle C, Part I, Sec. 13001(d)(3)(B). For Kentucky Power, this amortization period is based on the Average Rate Assumption Method or "ARAM." By contrast, the TCJA does not require that unprotected excess ADFIT be amortized over any specific period. Beginning July 1, 2018, customer bills included a credit to reflect the amortization of both protected and unprotected excess ADFIT as provided for under Kentucky Power's Tariff F.T.C. The unprotected excess ADFIT balance will be fully refunded to customers by the date rates approved in this case become effective. Therefore, the Tariff F.T.C will include only the protected ADFIT amortization resulting from the TCJA going forward.

XI. CORPORATE ALTERNATIVE MINIMUM TAX

Q. WHAT IS THE INFLATION REDUCTION ACT OF 2022?

A. H.R. 5376, approved by Congress and signed into law on August 16, 2022, is referred to as the Inflation Reduction Act of 2022 or IRA. The stated purpose of the law was to curb inflation by reducing the deficit through the creation of significant changes relating to tax, climate change, energy, and health care.

Q. WHAT TAX CHANGE FROM THE IRA WILL HAVE AN IMPACT ON THE COMPANY?

A. The Corporate Alternative Minimum Tax ("CAMT") was established for applicable corporations with adjusted financial statement income ("AFSI") above $1 billion. The IRA imposes a tax equal to the excess of 15% of the corporation's AFSI (tentative minimum tax) for the taxable year over its regular income tax liability.[11]

Q. WHAT IS THE COMPANY PROPOSING REGARDING CAMT IN THIS PROCEEDING?

A. The Company is proposing to include future CAMT within the Tariff F.T.C. This will ensure that the amount of taxes customers pay reflects the actual tax expense the Company incurs, and to the extent the Company pays less than a base amount, the difference will be credited to customers via Tariff F.T.C.

Q. WHEN IS THE CAMT EFFECTIVE AND HOW IS IT COMPUTED?

A. The CAMT is effective for tax years beginning after 2022. The amount of CAMT paid is the excess of the computed tentative minimum tax for the taxable year

[11] IRC § 55(a)(2).

over the regular income tax liability. For example, if an applicable corporation had a tentative minimum tax of $110 and a regular income tax of $100, the applicable corporation would pay $10 of CAMT and $100 of regular income tax ($10 CAMT + $100 regular income tax = $110 tentative minimum tax).

Q. WHAT IS ADJUSTED FINANCIAL STATEMENT INCOME, OR AFSI, MENTIONED ABOVE?

A. AFSI is the basis on which the CAMT is calculated and is equal to an entity's net income or loss reported on its applicable financial statements with adjustments for various provisions provided in the IRA. AFSI includes an adjustment to disregard any federal income taxes which are taken into account on the taxpayer's applicable financial statement. AFSI also includes adjustments to allow tax depreciation deductions and disregard associated financial statement depreciation taken on such property. To the extent items included in financial statement depreciation relate to amounts that do not result in tax depreciation (i.e. tax repairs), no adjustment is required to disregard that financial statement depreciation.

Q. PLEASE PROVIDE AN EXAMPLE OF THE AFSI CALCULATION.

A. Please see Figure LMS-8 below for an example of the AFSI calculation.

Figure LMS-8

Pre-Tax Book Income	5,000
Federal Income Tax	(1,050)
Financial Statement Income	3,950
Add: Federal Income Tax	1,050
Add: Book Depreciation	500
Deduct: Tax Depreciation	(3,000)
Adjustments	(1,450)
Adjusted Financial Statement Income	2,500

In this example, the financial statement income is $3,950 after federal income tax of $1,050. Adjustments to the financial statement income include an addition for federal income tax of $1,050, an addition for book depreciation of $500, and a deduction for tax depreciation of $3,000 for a total adjustment to the financial statement income of ($1,450). The AFSI is then $2,500 ($3,950 financial statement income - $1,450 of adjustments = $2,500 AFSI).

Q. HOW DOES THE CALCULATION OF AFSI COMPARE TO THE CALCULATION OF TAXABLE INCOME FOR THE REGULAR INCOME TAX?

A. The calculation of AFSI is limited in the adjustments for differences between the recognition of income and expense for book financial statement and tax purposes. The calculation of taxable income for the regular income tax incorporates all of these differences. Please see Figure LMS-9 below for a comparison of the calculation of AFSI and taxable income for the regular income tax.

Figure LMS-9

	AFSI	Taxable Income
Pre-Tax Book Income	5,000	5,000
Federal Income Tax	(1,050)	(1,050)
Financial Statement Income	3,950	3,950
Add: Federal Income Tax	1,050	1,050
Add: Book Depreciation	500	500
Deduct: Tax Depreciation	(3,000)	(3,000)
Add: Other Misc. Book/Tax Differences	0	200
Deduct: Other Misc. Book/Tax Differences	0	(1,200)
Adjustments	(1,450)	(2,450)
AFSI / Taxable Income	2,500	1,500

In this example comparison, the taxable income for the regular income tax includes an addition of $200 and a deduction of $1,200 for two differences in book and tax recognition of revenue and expenses that were not included in the calculation of AFSI. Common examples of these adjustments are the timing difference associated with the book accrual of expenses which are not deductible for tax purposes until paid or the book deferral of expenses that are recognized in the future in conjunction with rate recovery but are deductible for tax purposes the year in which the expenses are incurred.

Q. WHAT TAX RATES ARE APPLIED TO THE AFSI AND TAXABLE INCOME?

A. The calculation of the CAMT applies a 15 percent tax rate to AFSI while the calculation of the regular income tax applies a 21 percent tax rate to taxable income.

Q. WHAT IS THE TENTATIVE MINIMUM TAX MENTIONED ABOVE, AND HOW IS IT CALCULATED?

A. The tentative minimum tax is the CAMT due before considering any amount of tax due for the regular income tax. The tentative minimum tax is equal to 15 percent of AFSI.

Q. HOW IS THE CAMT CALCULATED?

A. CAMT is the excess, if any, of the tentative minimum tax over the regular 21 percent income tax. If the tentative minimum tax does not exceed the regular income tax, no CAMT is due.

Using the same example used earlier in my testimony in which AFSI is $2,500, the tentative minimum tax is $375 ($2,500 AFSI x 15 percent CAMT tax rate = $375 tentative minimum tax) and the regular income tax is $315 ($1,500 taxable income x 21 percent income tax rate = $315 regular income tax). Because the tentative minimum tax exceeds the regular income tax, the taxpayer in this example is liable for a CAMT of $60 in addition to the regular income tax of $315 ($375 tentative minimum tax - $315 regular income tax = $60 CAMT).

Figure LMS-10

Adjusted Financial Statement Income	2,500
CAMT Rate	15%
Tentative Minimum Tax	375
Taxable Income	1,500
Income Tax Rate	21%
Regular Income Tax	315
Corporate Alternative Minimum Tax	60

In this example, the taxpayer would have total taxes payable of $375, an increase of $60 over the taxes that would have been payable absent the CAMT imposed with the enactment of the IRA.

Q. CAN THE CAMT PAID IN A PRIOR TAX YEAR BE USED AS A CREDIT AGAINST A FUTURE INCOME TAX LIABILITY?

A. Yes. A taxpayer is eligible to claim a tax credit against the regular income tax for CAMT paid in a prior tax year to the extent that the regular income tax liability exceeds the tentative minimum tax in that tax year ("Minimum Tax Credit"). The carryforward of the Minimum Tax Credit is indefinite and can be used in any subsequent tax year.

If the taxpayer in my earlier example has AFSI of $2,500 and taxable income of $2,000 in the year subsequent to that example ("Year 2") it would result in a tentative minimum tax of $375 ($2,500 AFSI x 15 percent = $375) and regular income tax of $420 ($2,000 taxable income x 21 percent = $420). Because the tentative minimum tax does not exceed the regular income tax, the taxpayer does not have a CAMT payable in Year 2.

Figure LMS-11

	Year 2
Adjusted Financial Statement Income	2,500
CAMT Rate	15%
Tentative Minimum Tax	375
Taxable Income	2,000
Income Tax Rate	21%
Regular Income Tax	420
Corporate Alternative Minimum Tax	0

In this example, the taxpayer had paid $60 of CAMT in Year 1 and is eligible to claim a Minimum Tax Credit against the regular income tax liability in a future tax year to the extent that the regular income tax liability exceeds the tentative minimum tax in that tax year. In Year 2, the regular income tax exceeds the tentative minimum tax by $45 ($420 regular income tax less $375 tentative minimum tax = $45). In Year 2, the taxpayer would therefore have taxes payable of $375 ($420 regular income tax + $0 CAMT - $45 Minimum Tax Credit = $375 taxes payable).

Figure LMS-12

	Year 1	Year 2
Adjusted Financial Statement Income	2,500	2,500
CAMT Rate	15%	15%
Tentative Minimum Tax	375	375
Taxable Income	1,500	2,000
Income Tax Rate	21%	21%
Regular Income Tax	315	420
Corporate Alternative Minimum Tax	60	0
Total Tax Due before CAMT Credit	375	420
Less: CAMT Credit Utilized	0	45
Total Tax Due	375	375

In this example, the taxpayer would have $15 of Minimum Tax Credit available to claim against the regular income tax in Year 3 and beyond ($60 CAMT paid in Year 1 less $45 Minimum Tax Credit claimed in Year 2 = $15 CAMT Credit remaining).

Q. IS KENTUCKY POWER AN APPLICABLE CORPORATION SUBJECT TO THE CAMT?

A. Yes. Based on the definition of Applicable Corporation in IRC §59[12] and the guidance issued by the Internal Revenue Service in Notice 2023-7[13] it has been determined that Kentucky Power is an applicable corporation subject to the CAMT.

Q. IS AN ESTIMATE OF CAMT LIABILITY FOR 2023 INCLUDED IN THIS CASE?

A. No. The Company has accrued a deferred tax asset of $770,063 for the first quarter of 2023 for the CAMT. This amount was removed from the case as part of Section V, Exhibit 2, Adjustment #63. Although the Company is currently accruing an estimate for CAMT, the final amount will not be known until the filing of the 2023 federal tax return which will be filed by September 15, 2024. The Company will include the 2023 final amount in the October 2024 filing of the Tariff F.T.C. subject to Commission approval. The Tariff F.T.C is covered in the testimony of Company Witnesses Kahn and Spaeth.

XII. SECURITIZATION

Q. WHAT IS THE AMOUNT OF ADFIT THAT IS AN INPUT TO THE NET PRESENT VALUE CALCULATION OF THE SECURITIZATION?

The ADFIT for the Decommissioning Rider Regulatory Asset is $60,730,638 and for the Rockport Deferral Regulatory Asset is $10,973,148.

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[12] §59(k)(1)

[13] Notice 2023-7 2.01(4)(b)(ii)

Q. WHY DO DEFERRED TAX LIABILITIES EXIST ON THE DECOMMISSIONING RIDER REGULATORY ASSET AND THE ROCKPORT DEFERRAL REGULATORY ASSET?

A. ADFIT exists on the Decommissioning Rider Regulatory Asset because, for tax purposes, the Big Sandy Plant coal related assets were retired in 2015 and a tax loss was taken on the federal income tax return for the remaining tax basis of the assets. ADFIT exists on the Rockport Deferral Regulatory Asset because the related purchased power costs were deducted on a previously filed federal income tax return when incurred. The deferred income tax liabilities which exist on the Decommissioning Rider Regulatory Asset and the Rockport Deferral Regulatory Asset represent the difference between the income-tax effected net book value and net tax value, which is zero, and recognize that income taxes payable in future years will be higher as the regulatory assets are recovered because the benefit of the respective tax deductions have already been taken.

Q. DOES THE STAND-ALONE NOLC AFFECT THE ADFIT CALCULATION?

A. No. The stand-alone NOLC calculation is based on tax losses driven by accelerated depreciation. Because the drivers of the ADFIT on the Decommissioning Rider Regulatory Assets and the Rockport Deferral Regulatory Asset are not accelerated depreciation, the calculation is not affected by the stand-alone NOLC.

XIII. CONCLUSION

Q. OVERALL, WHAT ARE THE BENEFITS TO CUSTOMERS ASSOCIATED WITH THE COMPANY'S PROPOSED TAX TREATMENTS DESCRIBED IN YOUR TESTIMONY?

A. The Company's proposed tax treatments ensure that the Company properly collects tax expenses through rates that are equivalent to those incurred on the financial statements and therefore the Company can continue to provide safe and reliable service at an affordable price to customers. The proposals also ensure that the Company complies with the normalization requirements set forth in the Internal Revenue Code.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, Linda M. Schlessman, being duly sworn, deposes and says she is the Tax Accounting and Regulatory Support Manager for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Linda M. Schlessman

Commonwealth of Kentucky	)	
	)	Case No. 2023-00159
County of Boyd	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Linda M. Schlessman, on June 22, 2023.

Scott E. Bishop
Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

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Private Letter Ruling 201436037, 09/05/14, IRC Sec(s). 167

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-computation based on with or without basis-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of regulated electric utility's rate base by full amount of its ADIT account balances offset by portion of its NOLC-related account that is less than amount attributable to accelerated depreciation computed on "with or without" basis would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 167; Code Sec. 168;

Full Text:

Number: **201436037**

Release Date: 9/5/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-148310-13

Date:

May 22, 2014

LEGEND:

Taxpayer =

Parent =

State A =

State B =

State C =

Commission A =

Commission B =

Commission C =

Year A =

Year B =

Date A =

Date B =

Date C =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated November 25, 2013, of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State A and State B. It is wholly owned by Parent. Taxpayer is engaged in the transmission, distribution, and supply of electricity in State A and State C. Taxpayer is subject to the regulatory jurisdiction of Commission A, Commission B, and Commission C with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis. Taxpayer takes accelerated depreciation, including "bonus depreciation" where available and, for each year beginning in Year A and ending in Year B, Taxpayer individually (as well as the consolidated return filed by Parent) has or expects to, produce a net operating loss (NOL). On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an net operating loss carryover (NOLC). Taxpayer, for normalization purposes, calculates the portion of the NOLC attributable to accelerated depreciation using a "with or without" methodology, meaning that an NOLC is attributable to accelerated depreciation to the extent of the lesser of the accelerated depreciation or the NOLC.

Taxpayer filed a general rate case with Commission B on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission B policy and were not flowed thru to ratepayers. The data originally filed in Case included six months of forecast data, which the Taxpayer updated with actual data in the course of proceedings. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission B offset rate base by Taxpayer's ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Testimony by various other participants in Case argued against Taxpayer's proposed calculation of ADIT. One proposal made to Commission B was, if Commission B allowed Taxpayer to reduce the ADIT balance as Taxpayer proposed, then Taxpayer's income tax expense element of service should be reduced by that same amount.

Commission B, in an order issued on Date C, allowed Taxpayer to reduce ADIT by the amount that Taxpayer calculates did not actually defer tax due to the presence of the NOLC and ordered Taxpayer to seek a ruling on the effects of an NOLC on ADIT. Rates went into effect on Date C.

Taxpayer proposed, and Commission B accepted, that it be permitted to annualize, rather than average, its reliability plant additions and to extend the period of anticipated reliability plant additions to be included in rate base for an additional quarter. Taxpayer also proposed, and Commission B accepted, that no additional ADIT be reflected as a result of these adjustments inasmuch as any additional book and tax depreciation produced by considering these assets would simply increase Taxpayer's NOLC and thus there would be no net impact on ADIT.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.
3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In Case, Commission B has reduced rate base by Taxpayer's ADIT account, as modified by the account which Taxpayer has designed to calculate the effects of the NOLC. Section 1.167(1)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Further, while that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission B is in accord with the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the second issue, § 1.167(1)-(h)(6)(i) provides, as noted above, that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Increasing Taxpayer's ADIT account by an amount representing those taxes that would have been deferred absent the NOLC increases the ADIT reserve account (which will then reduce rate base) beyond the permissible amount.

Regarding the third issue, reduction of Taxpayer's tax expense element of cost of service, we believe that such reduction would, in effect, flow through the tax benefits of accelerated depreciation deductions through to rate payers even though the Taxpayer has not yet realized such benefits. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.
3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201438003, 09/19/2014, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated electric utility's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201438003**

Release Date: 9/19/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-104157-14

Date:

June 12, 2014

LEGEND:

Taxpayer =

Parent =

State A =

Commission A =

Commission B =

Year A =

Year B =

Year C =

Year D =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated January 24, 2014, and additional submission dated May 19, 2014, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated, investor-owned public utility incorporated under the laws of State A primarily engaged in the business of supplying electricity in State A. Taxpayer is subject to the regulatory jurisdiction of Commission A and Commission B with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis.

Taxpayer is wholly owned by Parent, and Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer used as its starting point actual data from the historic test period, calendar Year A. It then projected data for Year B through Year C. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. Rates in this proceeding were intended to, and did, go into effect for the period Date B through Date C.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available in all years for which data was provided. Additionally, Taxpayer forecasted that it would incur a net operating loss (NOL) in Year D. Taxpayer anticipated that it had the capacity to carry back a portion of this NOL with the remainder producing a net operating loss carryover (NOLC) as of the end of Year D.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced as of the end of Year D by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules Testimony by another participant in Case argued against Taxpayer's proposed calculation of ADIT.

Commission A, in an order issued on Date D, held that it is inappropriate to include the NOL in rate base for ratemaking purposes. Commission A further stated that it is the intent of the Commission that Taxpayer comply with the normalization method of accounting and tax normalization regulations. Commission noted that if Taxpayer later obtains a ruling from the IRS which affirms Taxpayer's position, Taxpayer may file seeking an adjustment. Commission A also held that to the extent tax normalization rules require recording the NOL to rate base in the specified years, no rate of return is authorized.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission A is not in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would, in effect, flow the tax benefits of accelerated depreciation deductions through to rate payers. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201519021, 05/08/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/investor-owned public utility's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201519021**

Release Date: 5/8/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-136851-14

Date:

February 04, 2015

LEGEND:

Taxpayer =

Parent =

State A =

Commission =

Year A =

Year B =

Year C =

Year D =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated October 1, 2014, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated, investor-owned public utility incorporated under the laws of State A primarily engaged in the business of supplying natural gas service in State A. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and as to the rates it may charge for the provision of service. Taxpayer's rates are established on a cost of service basis.

Taxpayer is wholly owned by Parent, and Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer used as its starting point actual data from the historic test period, calendar Year A. It then projected data for Year B through Year D. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. Rates in this proceeding were intended to, and did, go into effect for the period Date B through Date C.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available in all years for which data was provided. Additionally, Taxpayer forecasted that it would incur a net operating loss (NOL) in each of Year B, Year C, and Year D. Taxpayer anticipated that it had the capacity to carry back a portion of this NOL with the remainder producing a net operating loss carryover (NOLC) as of the end of Year C and Year D, the beginning and end of the test period.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced as of the end of Year D by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules Testimony by another participant in Case argued against Taxpayer's proposed calculation of ADIT.

Commission, in an order issued on Date D, held that it is inappropriate to include the NOL in rate base for ratemaking purposes. Commission further stated that it is the intent of the Commission that Taxpayer comply with the normalization method of accounting and tax normalization regulations. Commission noted that if Taxpayer later obtains a ruling from the IRS which affirms Taxpayer's position, Taxpayer may file seeking an adjustment. Commission also held that to the extent tax normalization rules require including the NOL in rate base in the specified years, no rate of return is authorized.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission is not in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers.

Under these specific facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would, in effect, flow the tax benefits of accelerated depreciation deductions through to rate payers. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of the Associate Chief Counsel

(Passthroughs & Special Industries)

Private Letter Rulings

Private Letter Ruling 201534001, 08/21/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryforward-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/common parent/regulated natural gas distributor's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201534001**

Release Date: 8/21/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-103300-15

Date:

May 13, 2015

LEGEND:

Taxpayer =

State A =

State B =

State C =

Commission =

Year A =

Year B =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated January 9, 2015, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is the common parent of an affiliated group of corporations and is incorporated under the laws of State A and State B. Taxpayer is engaged primarily in the businesses of regulated natural gas distribution, regulated natural gas transmission, and regulated natural gas storage. Taxpayer's regulated natural gas distribution business delivers gas to customers in several states, including State A. Taxpayer is subject to, as relevant for this ruling, the regulatory jurisdiction of Commission with respect to terms and conditions of service and as to the rates it may charge for the provision of its gas distribution service in State A. Taxpayer's rates are established on a "rate of return" basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer's application was based on a fully forecasted test period consisting of the twelve months ending on Date B. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. In a final order dated Date C, rates were approved by Commission for service rendered on or after Date D.

In each year from Year A to Year B, Taxpayer incurred a net operating loss carryforward (NOLC). In each of these years, Taxpayer claimed accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available. On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State C, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules. The attorney general for State C argued against Taxpayer's proposed calculation of ADIT.

Commission, in its final order, agreed with Taxpayer but concluded that the ambiguity in the relevant normalization regulations warranted an assessment of the issue by the IRS and this ruling request followed.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account that is less than the amount attributable to accelerated depreciation computed on a "last dollars deducted" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, to reduce Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "last dollars deducted" methodology employed by Taxpayer ensures that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these specific facts, any method other than the "last dollars deducted" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of the Associate Chief Counsel

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201548017, 11/27/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryforward-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated natural gas distributor's rate base by balance of its ADIT accounts unreduced by its NOLC-related deferred tax account, by full amount of its ADIT account balances offset by portion of NOLC-related account balances, or any reduction in taxpayer's tax expense element of cost of service to reflect tax benefit of its NOLC would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201548017**

Release Date: 11/27/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-116998-15

Date:

August 19, 2015

LEGEND:

Taxpayer =

Parent =

State A =

State B =

Commission =

Year A =

Year B =

Date A =

Date B =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated May 14, 2015, of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is primarily engaged in the regulated distribution of natural gas in State A. It is incorporated in State B and is wholly owned by Parent. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis. Taxpayer takes accelerated depreciation, including "bonus depreciation" where available and, for each year beginning in Year A and ending in Year B, Taxpayer incurred net operating losses (NOL). On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an net operating loss carryover (NOLC). Taxpayer, for normalization purposes, calculates the portion of the NOLC attributable to accelerated depreciation using a "last dollars deducted" methodology, meaning that an NOLC is attributable to accelerated depreciation to the extent of the lesser of the accelerated depreciation or the NOLC.

Taxpayer filed a general rate case with Commission on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed thru to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission offsets rate base by Taxpayer's ADIT balance. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Testimony by various other participants in Case argued against Taxpayer's proposed calculation of ADIT. One proposal made to Commission was, if Commission allowed Taxpayer to reduce the ADIT balance as Taxpayer proposed, then an offsetting reduction should be made to Taxpayer's income tax expense element of service.

A Utility Law Judge upheld Taxpayer's position with respect to the NOLC-related ADIT and ordered Taxpayer to seek a ruling from the Internal Revenue Service on this matter. This request is in response to that order.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the balance of its ADIT accounts unreduced by its NOLC-related deferred tax account would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
2. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "last dollars deducted" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.
3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(1)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Further, while that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the proposed order by the Utility Law Judge upholding Taxpayer's position that the NOLC-related deferred tax account must be included in the calculation of Taxpayer's ADIT is in accord with the normalization requirements. The "last dollars deducted" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "last dollars deducted" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, reduction of Taxpayer's tax expense element of cost of service, we believe that such reduction would, in effect, flow through the tax benefits of accelerated depreciation deductions through to rate payers even though the Taxpayer has not yet realized such benefits. In addition, such adjustment would be made specifically to mitigate the effect of the normalization rules in the calculation of Taxpayer's NOLC-related ADIT. In general, taxpayers may not adopt any accounting treatment that directly or indirectly circumvents the normalization rules. See generally, § 1.46-6(b)(2)(ii) (In determining whether, or to what extent, the investment tax credit has been used to reduce cost of service, reference shall be made to any accounting treatment that affects cost of service); Rev. Proc 88-12, 1988-1 C.B. 637, 638 (It is a violation of the normalization rules for taxpayers to adopt any accounting treatment that, directly or indirectly flows excess tax reserves to ratepayers prior to the time that the amounts in the vintage accounts reverse). This "offsetting reduction" would violate the normalization provisions.

Based on the representations submitted by Taxpayer, we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the balance of its ADIT accounts unreduced by its NOLC-related deferred tax account would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "last dollars deducted" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of Associate Chief Counsel

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201709008, 03/03/17, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated cost recovery system-normalization-accumulated deferred income tax-net operating loss carryforward-limitations on reasonable allowance in case of property of public utilities.

Headnote:

In order to avoid violation of Code Sec. 168(i)(9); 's and Reg § 1.167(l)-1 's normalization requirements, it was necessary to include in regulated integrated electric utility/sub.'s rate base ADIT asset resulting from NOL carryforward, given inclusion in rate base of full amount of ADIT liability resulting from accelerated tax depreciation.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201709008**

Release Date: 3/3/2017

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-119381-16

Date:

December 02, 2016

LEGEND:

Taxpayer =

Parent =

State =

Commission A =

Commission B =

Date 1 =

Date 2 =

Date 3 =

Date 4 =

Date 5 =

Case =

Year 1 =

Year 2 =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated June 15, 2016, submitted by Parent on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is an integrated electric utility headquartered in State. Taxpayer is a wholly owned subsidiary of Parent and is included in Parent's consolidated federal income tax return. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer's business includes retail electric utility operations regulated within State by Commission A and Taxpayer is subject to the regulatory jurisdiction of Commission B with respect to terms and conditions of its wholesale electric transmission service and as to the rates it may charge for the provision of such services. Taxpayer's rates are established on a cost of service basis.

On Date 1, Taxpayer filed a rate case application (Case) with Commission B requesting authorization to change from charging stated rates for wholesale electric transmission service to a formula rate mechanism pursuant to which rates for wholesale transmission service are calculated annually in accordance with an approved formula. The proposed formula consisted of updating cost of service components, including investment in plant and operating expenses, based on information contained in Taxpayer's annual financial report filed with Commission B, as well as including projected transmission capital projects to be placed into service in the following year. The projections included are subject to true-up in the following year's formula rate.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available. Taxpayer incurred a net operating loss (NOL) in each of Year 1 through Year 2 due to Taxpayer's claiming bonus depreciation, producing a net operating loss carryover (NOLC).

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of a NOLC.

In the setting of utility rates by Commission B, a utility's rate base is offset by its ADIT balance. In its rate case filing, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules.

On Date 2, Commission B issued an order accepting Taxpayer's revisions to its rates. On Date 3, new rates went into effect, subject to refund. Several intervenors submitted challenges to the rate case and on Date 4, Taxpayer and those intervenors entered into a Settlement Agreement, which was filed with Commission B. On Date 5, Commission B issued an order accepting the Settlement Agreement, which allows for the inclusion of the ADIT related to the NOLC asset in rate base.

Commission B further stated in the order that it is the intent of Commission B that Taxpayer comply with the normalization method of accounting and tax normalization regulations. The order also requires Taxpayer to seek a private letter ruling (PLR) from the Service regarding Taxpayer's treatment of the ADIT related to the NOLC asset. Commission B also noted that after the Service issues a PLR, Taxpayer shall adjust, to the extent necessary, its ratemaking treatment of the ADIT related to the NOLC asset prospectively from the date of the PLR.

Taxpayer requests that we rule as follows:

1. In order to avoid a violation of the normalization requirements of § 168(i)(9) and Treasury Regulation § 1.167(l)-1, it is necessary to include in rate base the Accumulated Deferred Income Tax (ADIT) asset resulting from the Net Operating Loss Carryforward (NOLC), given the inclusion in rate base of the full amount of the ADIT liability resulting from accelerated tax depreciation.
2. The exclusion from rate base of the entire ADIT asset resulting from the NOLC, or the inclusion in rate base of a portion of that ADIT asset that is less than the amount attributable to accelerated tax depreciation, computed on a "with and without" basis, would violate the normalization requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A)(i) requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that-would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under § 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under § 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under § 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under § 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under § 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under § 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under § 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the reserve account for deferred taxes (ADIT), reduces rate base, it is clear that the portion of the net operating loss carryover (NOLC) that is attributable to accelerated depreciation must be taken into account in calculating the amount of the ADIT account balance. Thus, the order by Commission to include in rate base the ADIT asset resulting from the NOLC, given the inclusion in rate base of the full amount of the ADIT liability resulting from accelerated tax depreciation is in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these specific facts, any method other than the "with or without" method would not provide the same level of certainty and therefore the use of any other methodology in computing the portion of the ADIT asset attributable to accelerated depreciation is inconsistent with the normalization rules.

We rule as follows:

1. In order to avoid a violation of the normalization requirements of § 168(i)(9) and Treasury Regulation § 1.167(l)-1, it is necessary to include in rate base the Accumulated Deferred Income Tax (ADIT) asset resulting from the Net Operating Loss Carryforward (NOLC), given the inclusion in rate base of the full amount of the ADIT liability resulting from accelerated tax depreciation.
2. The exclusion from rate base of the entire ADIT asset resulting from the NOLC, or the inclusion in rate base of a portion of that ADIT asset that is less than the amount attributable to accelerated tax depreciation, computed on a "with and without" basis, would violate the normalization requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Patrick S. Kirwan

Chief, Branch 6

Office of the Associate Chief Counsel

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 202010002, 03/06/2020, IRC Sec(s). 168

UIL No. 168.24-01

Depreciation-accelerated cost recovery system-accumulated deferred income taxes-rate base calculations-normalization rules-net operating loss carryforwards-public utilities.

Headnote:

In order to comply with normalization method of accounting within meaning of Code Sec. 168(i)(9); under described circumstances, amount of depreciation-related ADIT reducing rate base used to determine revenue requirement set in surcharge proceeding must be decreased to reflect portion of NOL for test period for that proceeding which wouldn't have arisen had taxpayer not reported depreciation-related book/tax differences during test period, and such decrease in depreciation-related ADIT must be amount that is no less than amount computed using With-and-Without Method.

Reference(s): Code Sec. 168;

Full Text:

Number: **202010002**

Release Date: 3/6/2020

Index Number: 168.24-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-113227-19

Date: December 3, 2019

In Re: [Redacted Text]

LEGEND:

Taxpayer =

Parent =

State A =

State B =

Commission =

Date 1 =

Date 2 =

Date 3 =

Date 4 =

Date 5 =

Date 6 =

Date 7 =

Date 8 =

Date 9 =

Date 10 =

Date 11 =

Date 12 =

Date 13 =

Date 14 =

Date 15 =

Date 16 =

Month 1 =

Month 2 =

Month 3 =

Month 4 =

Month 5 =

Month 6 =

Year 1 =

Year 2 =

Year 3 =

Year 4 =

Year 5 =

a=

b=

c=

d=

e=

f=

g=

h=

i=

j=

k=

l=

Dear [Redacted Text]:

This letter responds to a request for a private letter ruling dated June 5, 2019, and submitted on behalf of Taxpayer for rulings under § 168(i)(9) of the Internal Revenue Code and § 1.167(l)-1 of the Income Tax Regulations (together, the "Normalization Rules") regarding the scope of the deferred tax normalization requirements and the appropriate methodology for the reduction of the accumulated deferred income tax ("ADIT") balance that decreases rate base computation when a net operating loss carryforward ("NOLC") exists. The relevant facts as represented in your submission are set forth below.

FACTS

Taxpayer files a consolidated federal income tax return on a calendar year basis with its affiliates, including its Parent. Taxpayer uses the accrual method of accounting.

Parent is incorporated in State A, and Taxpayer is incorporated in State B. Parent is a water and wastewater utility company. Taxpayer is the affiliate that operates in State B. Prices charged by Taxpayer are set by Commission. Commission sets rates that Taxpayer may charge for the furnishing or sale of water or sewage disposal services through a combination of periodic general rate case proceedings (resulting in what are commonly referred to as "base rates") and infrastructure surcharge proceedings (resulting in surcharges that are added to base rates.)

The most recent two base rate changes resulting from general rate case authorizations by Commission affecting water and wastewater revenue requirements were effective in Month 1 Year 1 and Month 2 Year 2. The most recent three rate changes resulting from infrastructure surcharge authorizations by Commission were effective in Month 3 Year 3, Month 4 Year 4 and Month 4 Year 2. Taxpayer questions whether the rates set pursuant to the most recent infrastructure surcharge proceeding comply with the deferred tax normalization requirements.

Infrastructure surcharges are regulatory mechanisms to permit recovery of capital investments and results in adjustments to rates charged outside of a general rate case for specified costs and investments. Under State B statute and Commission rulemaking, eligible water corporations may petition Commission and utilize a Infrastructure System Replacement Surcharge ("Surcharge") to recover the costs of eligible water utility main replacements and relocations.

For both general rate case proceedings and Surcharge proceedings, Taxpayer computes a revenue requirement subject to Commission approval based on recovery of a debt- and equity-based return on investment in rate base, including the cost of plant assets less accumulated book depreciation and ADIT, and a recovery of operating expenses, including depreciation expense, property tax expense, and income tax expense. For Surcharge proceedings, rate base is determined based on incremental plant expenditures incurred during a historical measurement period (not necessarily 12 months) ending shortly before rates become effective, less accumulated book depreciation and ADIT computed as of a date subsequent to the date at which gross plant is computed and closer to (but preceding) the date that rates become effective. For Surcharge proceedings, operating expenses include 12 months of annualized depreciation expense on the incremental investment in the Surcharge proceeding and any property taxes that will be paid within 12 months of filing the Surcharge application.

The deferred tax normalization matters in this request arose during the Surcharge proceeding initiated by Taxpayer in Month 5 Year 2 and resulting in a Commission order on Date 1 (the "Surcharge Case"). The Surcharge resulting from the Surcharge Case became effective on Date 2. Some of the normalization matters addressed in this ruling request related to deductions and ADIT resulting from the consent agreement that Parent received from the Service on Date 3, on behalf of itself and various affiliates, including Taxpayer, with respect to changes in tax method of accounting for costs to repair and maintain tangible property and dispositions of certain tangible depreciable property ("Consent Agreement").

State B statutes and Commission B rules provide eligible water corporations with the ability to recover certain infrastructure system replacement costs outside of a formal rate case filing via a Surcharge. A petition must be filed with the Commission for review and approval before an adjustment can be made to a water corporation's rates and charges to provide for the recovery of the costs associated with eligible infrastructure system replacements. A State B statute authorizes Commission to enter an order authorizing the water corporation to impose a Surcharge that is sufficient to recover appropriate pretax revenues. The State B statute defines the revenue requirement set in a Surcharge proceeding and provides that "appropriate pretax revenues" are the revenues necessary to produce net operating income equal to the water corporation's weighted cost of capital multiplied by the net original cost of eligible infrastructure system replacements, including recognition of accumulated deferred income taxes and accumulated depreciation associated with eligible infrastructure system replacements..." among other items. Taxpayer represents that Commission and the State B courts have interpreted this statute in a strict manner thereby limiting the costs eligible for recovery or to earn a return in a Surcharge proceeding and causing costs not eligible for ratemaking consideration in a Surcharge proceeding to only be eligible for recovery or return in the next base rate proceeding.

Taxpayer, per its petition filed with Commission on Date 4, sought to establish a Surcharge rate to provide for the recovery of actual costs for eligible infrastructure system replacements and relocations from Date 5 through Date 6, and estimated investment accounts for Date 7 through Date 8. During the course of the Surcharge case, Taxpayer provided Commission with actual expenditures for Month 5 and Month 6. The proposed Surcharge rate schedule reflected the pre-tax Surcharge revenues necessary to produce net operating income equal to Taxpayer's weighted cost of capital multiplied by the original cost of the requested infrastructure replacements that are eligible for the Surcharge, reduced by net ADIT and accumulated depreciation associated with eligible infrastructure system replacements through Date 9. Taxpayer also sought to recover all state, federal and local income or excise taxes applicable to such Surcharge income and to recover all other Surcharge costs including annualized depreciation expense and property taxes due within 12 months.

The specific test period and service period information pertaining to the Surcharge Case is:

- Rates became effective Date 2
- Actual gross plant was based on additions of certain property placed in service from Date 5 through Date 8
- Accumulated depreciation on such assets was estimated through Date 9
- Estimated ADIT related to depreciation book/tax differences associated with such expenditures to the extent also capitalized for tax purposes was computed through Date 9
- Estimated ADIT related to repair book/tax differences associated with such expenditures to the extent not capitalized for tax purposes was computed through Date 9
- Recoverable operating expenses were estimated for the period beginning Date 10 and ending Date 9

In a Surcharge proceeding, replacement mains and associated valves and hydrants comprise the plant assets included in rate base and result in the accumulated depreciation reducing rate base and the recoverable depreciation expense. The expenditures for replacement mains and associated valves addressed in a Surcharge proceeding are capitalizable for regulatory accounting purposes, but may result in a repair deduction for tax purposes or depreciable plant for tax purposes. The ADIT balance reducing rate base in a Surcharge proceeding is caused by depreciation-related and repair-related book/tax differences.

The key issues in the Surcharge case and, thus, in this ruling request, pertain to whether the tax effect of an NOLC must, pursuant to the normalization requirements, decrease the ADIT reduction to rate base related to the expenditures in the Surcharge case and, if so, the methodology to determine the amount of the NOLC adjustment subject to the normalization requirements. The return on rate base is based on the pre-tax rate of return authorized in the most recent rate order resulting from a general rate proceeding.

In the course of the Surcharge Case, Taxpayer and other participants in the proceeding analyzed the expenditures for which Taxpayer sought recovery via the Surcharge and debated the proper regulatory treatment of Taxpayer's NOLC and tax loss incurred through the rate base determination date of the Surcharge case with respect to the costs incurred that are recoverable in the Surcharge case. The revenue requirement approved in Commission's order issued on Date 1 was lower than the revenue requirement sought by Taxpayer and is entirely attributable to differing ADIT calculations with respect to the NOLC and the resulting effects on rate base and allowed return. The approved revenue requirement in the Surcharge case was based on a rate base computation that reflects the gross ADIT liabilities associated with depreciation-related and repair-related book/tax differences, but did not reflect an ADIT asset for any portion of Taxpayer's NOLC as of the date that rate base was determined (Date 9), including the tax loss resulting from the infrastructure expenditures addressed in the Surcharge Case.

On a consolidated basis, Parent incurred tax losses in various years from Year 5 to Year 1 and, as of Date 11, had an NOLC of approximately $a. On a separate company basis, Taxpayer incurred tax losses in various tax years from Year 5 -Year 1 and, as of Date 11, had a separate company NOLC of approximately $b. For Year 2, Parent (on a consolidated basis) and Taxpayer (on a separate company basis) estimate that taxable income was earned and, thus, NOLC was utilized.

The revenue requirement related to the Surcharge Case is approximately $c (pursuant to the rate order). Taxpayer asserts that the revenue requirement should have been computed to be $d. The difference in the revenue requirement computations relates entirely to the exclusion of Taxpayer's NOLC from rate base. As of the date of the rate base determination, none of the Surcharge revenues had been billed to customers and, thus, as of such date, a taxable loss of approximately $e had been incurred with respect to the plant-related expenditures with rates set by the Surcharge Case.

During the loss years resulting in Taxpayer's NOLC estimated as of the end of the test period for the Surcharge Case, separate company deductible depreciation-related book/tax differences were approximately $f and separate company deductible repair-related book/tax differences were approximately $g (plus the § 481(a) adjustment with respect to the tax accounting method changes subject to the Consent agreement deducted in Year 5 of approximately $h.

The NOLC reflected in ratemaking for the base rate case proceeding with rates effective in Month 2 Year 2 was based on the estimated NOLC as of the end of Year 4 of $i, including an estimated Year 4 tax loss of $j. The actual Year 4 tax loss reported on the Year 4 tax return was $k. The excess of the actual Year 4 tax loss over the estimated Year 4 tax loss of $l has yet to be reflected in ratemaking.

On Date 12, Taxpayer filed an Application for Rehearing and Motion to Defer Ruling, asking the Commission for the time to seek a private letter ruling form of guidance from the Service to address any uncertainties regarding the application of the deferred tax normalization requirements to the rate base treatment of the NOLC-related ADIT asset in computing the Surcharge case revenue requirement. On Date 13, the Commission denied Taxpayer's request for rehearing. Taxpayer filed a notice of appeal by Date 14, that initiated an appeal of the order in the Surcharge case to the State B Court of Appeals.

Taxpayer anticipates receiving a private letter ruling from the Service prior to the State B Court of Appeals issuing a final opinion in Taxpayer's appeal of the Commission denial of Taxpayer's Motion for Rehearing. If the Service rules that the Commission's decision in Taxpayer's Surcharge case ordered a method of regulatory accounting that is inconsistent with the deferred tax normalization requirements, Taxpayer believes that the Commission and Taxpayer would be procedurally able to correct the revenue requirement in a manner that compensates Taxpayer for any foregone revenue requirement relative to ADIT and rate base computations that comply with the normalization requirements.

Because Taxpayer is concerned that the order issued by Commission as part of the Surcharge case on Date 1, and the prices that became effective on Date 2, are inconsistent with the deferred tax normalization requirements, Taxpayer submitted a letter to the Service on Date 14 intended to provide the notification pursuant to § 1.167(l)-1(h)(5) of the Regulations.

As noted, on Date 3, Taxpayer's parent corporation received the Consent Agreement from the Internal Revenue Service granting certain of its subsidiaries, including Taxpayer, permission to change their (1) method of accounting for costs to repair and maintain tangible property from capitalizing and depreciating these costs to deducting these costs under § 162 of the Internal Revenue Code, and (2) unit of property for determining dispositions of depreciable network assets from using a method other than the functional interdependence test to using the functional interdependence test to determine the units of property. These changes in methods of accounting were effective for the taxable year beginning Date 15, and ended Date 16 (the "year of change").

These changes in methods of accounting resulted in an overall net negative § 481(a) adjustment for Taxpayer as stated in the Consent Agreement. This overall net negative § 481(a) adjustment consists of a net negative § 481(a) adjustment for the repair and maintenance change in method of accounting and a net positive § 481(a) adjustment for the disposition change in method of accounting.

The Service's consent to the above changes in methods of accounting is subject to several terms and conditions stated in the Consent Agreement. Condition nine of the Consent Agreement requires that if any item of property subject to the taxpayer's Form 3115 is public utility property within the meaning of § 168(i)(10) or former § 167(I)(3)(A): (A) a normalization method of accounting (within the meaning of § 168(i)(9), former § 168(e)(3)(B), or former § 167(I)(3)(G), as applicable) must be used for the public utility property subject to the Form 3115; (B) as of the beginning of the year of change, the taxpayer must adjust its deferred tax reserve account or similar reserve account in the taxpayer's regulatory books of account by the amount of the deferral of federal income tax liability associated with the § 481(a) adjustment applicable to the public utility property subject to the Form 3115; and (C) within 30 calendar days of filing the federal income tax return for the year of change, the taxpayer must provide a copy of the Form 3115 (and any additional information submitted to the Service in connection with such Form 3115) to any regulatory body having jurisdiction over the public utility property subject to the Form 3115. See page 6 of the Consent Agreement.

Based on Taxpayer's interpretation of this condition in the Consent Agreement, Taxpayer has applied the normalization requirements to its repair-related and disposition-related deferred tax computations in rate proceedings since the year of change.

Prior to the year of change (Year 5), Taxpayer depreciated public utility property that was in service as of the end of the taxable year immediately preceding the year of change using different book and tax methods and lives. As a result, an amount of ADIT subject to the normalization requirements was recorded prior to the above changes in methods of accounting for repairs and dispositions (depreciation-related ADIT).

Differing assertions were made as part of the Surcharge Case. Ultimately the Commission in its final order determined that because there was not an NOL expected to be generated in Year 4, no portion of the NOLC deferred tax asset can be associated with the Surcharge property.

RULINGS REQUESTED

1) The property otherwise depreciable under § 168(a) and for which cost recovery and return on investment initially occur as part of the Surcharge Case, rather than as part of base rates set in less frequent general rate case proceedings, constitutes public utility property within the meaning of § 168(i)(10).

2) The ADIT amounts used in computing the revenue requirement set in the Surcharge Case with respect to public utility property within the meaning of § 168(i)(10) must comply with the normalization method of accounting within the meaning of § 168(i)(9).

3) For any public utility property within the meaning of § 168(i)(10) as of the end of the tax year immediately preceding the year of change for the changes in tax method of accounting subject to Taxpayer's Consent Agreement, the depreciation-related ADIT prior to the change in tax method of accounting for repairs and dispositions remains subject to the normalization method of accounting within the meaning of § 168(i)(9) after implementation of the new tax method of accounting.

4) For any public utility property within the meaning of § 168(i)(10) and subject to Taxpayer's Consent Agreement, the ADIT resulting from the repair-related § 481(a) adjustment is not subject to the normalization method of accounting within the meaning of § 168(i)(9).

5) The ADIT resulting from expenditures (1) related to an item of property includible in rate

base and recoverable as regulatory depreciation expense in the determination of the revenue requirement set in the Surcharge Case and (2) deducted as repairs under § 162 to public utility property within the meaning of § 168(i)(10), or a predecessor provision of the normalization requirements, pursuant to the tax method of accounting for repairs permitted in Taxpayer's Consent Agreement, is not subject to the normalization method of accounting within the meaning of § 168(i)(9) or, as applicable, a predecessor statutory provision.

6) The ADIT resulting from book/tax differences related to depreciable method and life for public utility property that exists at the date of a retirement of the property for regulatory accounting purposes in a transaction involving a replacement or relocation that is not treated as a disposition under Taxpayer's tax method of accounting for dispositions permitted in Taxpayer's Consent Agreement remains subject to the normalization method of accounting within the meaning of § 168(i)(9) after the book-only retirement.

7) For any public utility property within the meaning of § 168(i)(10) for which a disposition had been recognized for tax purposes in a tax year prior to the tax year of change for the changes in tax method of accounting subject to Taxpayer's Consent Agreement and for which the taxable gain or loss upon such disposition was reversed as part of the disposition-related § 481(a) adjustment, the ADIT related to the restored tax basis of such public utility property is subject to the normalization method of accounting within the meaning of § 168(i)(9), despite the book-only retirement.

8) If the Service rules as Taxpayer has requested with respect to issue # 5 and holds that ADIT resulting from repair-related book/tax differences is not subject to the normalization requirements, Taxpayer requests that the Service also rule: In order to comply with the normalization method of accounting within the meaning of § 168(i)(9), the amount of depreciation-related ADIT reducing rate base used to determine the revenue requirement set in the Surcharge Case is limited to the amount of depreciation-related deferred tax expense recovered in rates as of the Surcharge Case rate base determination date.

9) If the Service rules as Taxpayer has requested with respect to issue # 5 and holds that ADIT resulting from repair-related book/tax differences is not subject to the normalization requirements, Taxpayer requests that the Service also rule: Under the circumstances described above, in order to comply with the normalization method of accounting within the meaning of § 168(i)(9), the amount of depreciation-related ADIT reducing rate base used to determine the revenue requirement set in the Surcharge Case must be decreased to reflect a portion of the NOL for the test period for the Surcharge Case which would not have arisen had Taxpayer not reported depreciation-related book/tax differences during the text period for the Surcharge Case and such decrease in depreciation-related ADIT must be an amount that is no less than the amount computed using the With-and-Without Method.

10) If the Service (a) rules as Taxpayer has requested with respect to issue # 5 and holds

that ADIT resulting from repair-related book/tax differences is not subject to the normalization requirements, but (b) does not grant ruling # 9 in accordance with Taxpayer's analysis, Taxpayer requests that the Service instead rule: Under the circumstances described above, in order to comply with the normalization method of accounting within the meaning of § 168(i)(9), the amount of depreciation-related ADIT reducing rate base used to determine the revenue requirement set in the Surcharge Case must be decreased to reflect a portion of the NOLC which would not have arisen (or an increase in such NOLC which would not have arisen) had Taxpayer not reported depreciation-related book/tax differences during the test period for the Surcharge Case and such decrease in depreciation-related ADIT must be an amount that is no less than the amount computed using the With-and-Without Method but only to the extent that the NOLC has not reduced depreciation-related ADIT in rate base computation in another rate proceeding with prices still in effect.

11) If the Service rules as Taxpayer has requested with respect to issue # 5 and holds that ADIT resulting from repair-related book/tax differences is not subject to the normalization requirements, Taxpayer requests that the Service also rule: Under the circumstances described above, in order to comply with the normalization method of accounting within the meaning of § 168(i)(9), it is not necessary to decrease ADIT or otherwise increase rate base for the Surcharge Case by the portion of the NOLC which would not have arisen (or an increase in such NOLC which would not have arisen) had Taxpayer not reported depreciation-related book/tax differences in prior periods or during the test period for the Surcharge Case with respect to public utility property with rates not set by the Surcharge Case.

12) If the Service does not rule as Taxpayer has requested with respect to issue # 5 and holds that ADIT resulting from repair-related book/tax differences is subject to the normalization requirements, Taxpayer requests that the Service also rule: Under the circumstances described above, in order to comply with the normalization method of accounting within the meaning of § 168(i)(9), the amount of ADIT reducing rate base used to determine the revenue requirement set in the Surcharge Case must be decreased to reflect the portion of the Surcharge Case test period NOL which would not have arisen had Taxpayer not reported the depreciation-related book/tax difference or repair-related book/tax difference permitted in Taxpayer's Consent Agreement with respect to expenditures with ratemaking determined pursuant to the Surcharge Case, by an amount that is no less than the amount computed using the With-and-Without Method. If, instead, the Service rules as Taxpayer has requested with respect to issue # 5, ruling request # 12 would be moot.

LAW AND ANALYSIS

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

Section 168(i)(10) defines, in part, public utility property as property used predominantly in the trade or business of the furnishing or sale of electrical energy if the rates for such furnishing or sale, as the case may be, have been established or approved by a State or political subdivision thereof.

Prior to the Revenue Reconciliation Act of 1990, the definition of public utility property was contained in § 167(l)(3)(A) and § 168(i)(10), which defined public utility property by means of a cross reference to § 167(l)(3)(A). The definition of public utility property is unchanged. Section 1.167(l)-1(b) provides that under § 167(l)(3)(A), property is public utility property during any period in which it is used predominantly in a § 167(l) public utility activity. The term " section 167(l) public utility activity" means, in part, the trade or business of the furnishing or sale of electrical energy if the rates for such furnishing or sale, as the case may be, are regulated, i.e., have been established or approved by a regulatory body described in § 167(l)(3)(A). The term "regulatory body described in § 167(l)(3)(A)" means a State (including the District of Columbia) or political subdivision thereof, any agency or instrumentality of the United States or a public service or public utility commission or other body of any State or political subdivision thereof similar to such a commission. The term "established or approved" includes the filing of a schedule of rates with a regulatory body which has the power to approve such rates, though such body has taken no action on the filed schedule or generally leaves undisturbed rates filed by the taxpayer.

The definitions of public utility property contained in § 168(i)(10) and former § 46(f)(5) are essentially identical. Section 1.167(l)-1(b) restates the statutory definition providing that property will be considered public utility property if it is used predominantly in a public utility activity and the rates are regulated. Section 1.167(l)-1(b)(1) provides that rates are regulated for such purposes if they are established or approved by a regulatory body. The terms established or approved are further defined to include the filing of a schedule of rates with the regulatory body that has the power to approve such rates, even if the regulatory body has taken no action on the filed schedule or generally leaves undisturbed rates filed.

The regulations under former § 46, specifically § 1.46-3(g)(2), expand the definition of regulated rates. The expanded definition embodies the notion of rates established or approved on a rate of return basis. This notion is not specifically provided for in the regulations under former § 167. Nevertheless, there is an expressed reference to rate of return in § 1.167(l)-1(h)(6)(i). The operative rules for normalizing timing differences relating to use of different methods and periods of depreciation are only logical in the context of rate of return regulation. The normalization method, which must be used for public utility property to be eligible for the depreciation allowance available under § 168, is defined in terms of the method the taxpayer uses in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account. Thus, for purposes of applying the normalization rules, the definition of public utility property is the same for purposes of the investment tax credit and depreciation.

Section 168(f)(2) of the Code provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A)(i) requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (referred to as the "Consistency Rule").

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under § 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under § 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under § 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under § 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under § 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under § 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under § 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements of former § 167(l) with respect to public utility property defined in former § 167(l)(3)(A) pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account.

Section 481(a) requires those adjustments necessary to prevent amounts from being duplicated or omitted to be taken into account when a taxpayer's taxable income is computed under a method of accounting different from the method used to compute taxable income for the preceding taxable year. *See also* § 2.05(1) of Rev. Proc. 97-27, 97-27, 1997-1 C.B. 680 (the operative method change revenue procedure at the time Taxpayer filed its Form 3115, *Application for Change in Accounting Method*).

An adjustment under § 481(a) can include amounts attributable to taxable years that are closed by the period of limitation on assessment under § 6501(a). *Suzy's Zoo v. Commissioner*, 114 T.C. 1, 13 (2000), *aff'd*, 273 F.3d 875, 884 [88 AFTR 2d 2001-6916] (9th Cir. 2001); *Superior Coach of Florida,* *Inc. v. Commissioner*, 80 T.C. 895, 912 (1983), *Weiss v. Commissioner*, 395 F.2d 500 [22 AFTR 2d 5013] (10th Cir. 1968), *Spang Industries, Inc. v. United States*, 6 Cl. Ct. 38, 46 [54 AFTR 2d 84-5873] (1984), *rev'd on other grounds* 791 F.2d 906 [58 AFTR 2d 86-5052] (Fed. Cir. 1986). *See also Mulholland v. United States*, 28 Fed. Cl. 320, 334 [71 AFTR 2d 93-1916] (1993) (concluding that a court has the authority to review the taxpayer's threshold selection of a method of accounting *de novo*, and must determine, *ab initio*, whether the taxpayer's reported income is clearly reflected).

Sections 481(c) and 1.481-4 provide that the adjustment required by § 481(a) may be taken into accounting in determining taxable income in the manner, and subject to the conditions, agreed to by the Service and a taxpayer. Section 1.446-1(e)(3)(i) authorizes the Service to prescribe administrative procedures setting forth the limitations, terms, and conditions deemed necessary to permit a taxpayer to obtain consent to change a method of accounting in accordance with § 446(e). *See also* § 5.02 of Rev. Proc. 97-27.

When there is a change in method of accounting to which § 481(a) is applied, § 2.05(1) of Rev. Proc. 97-27 provides that income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed, and income for the year of change and the following taxable years must be determined under the new method of accounting as if the new method had always been used.

Regarding ruling requests 1 and 2, the key factors in determining whether property is public utility property are that (1) the property must be used predominantly in the trade or business of the furnishing or sale of, inter alia, water and wastewater; (2) the rates for such furnishing or sale must be established or approved by a State or political subdivision thereof, any agency or instrumentality of the United States, or by a public service or public utility commission or similar body of any State or political subdivision thereof; and (3) the rates so established or approved must be determined on a rate-of-return basis. State B statutes and Commission B rules provide eligible water corporations with the ability to recover certain infrastructure system replacement costs outside of a formal rate case filing via a Surcharge. These infrastructure system replacements will be predominantly used in the trade or business of the furnishing or sale of water and wastewater and therefore, it will possess the first of the three characteristics. Moreover, as a regulated public utility subject to the jurisdiction of federal or state law, including the ratemaking jurisdiction of the State B commission, the second requirement is met. Lastly, as evidenced by the facts, these rates are determined on a rate-of-return basis. After establishing that this involves public utility property, the law makes clear that the depreciation deduction determined under § 168 shall not apply to any public utility property if the taxpayer does not use a normalization method of accounting. The normalization regulations require a taxpayer to credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account.

Taxpayer's ruling request 3 pertains to the depreciation-related ADIT existing prior to the year of change ([Redacted Text]) for public utility property in service as of the end of the taxable year immediately preceding the year of change. Beginning with the year of change, the [Redacted Text] Consent Agreement granted Taxpayer permission to change its (1) method of accounting for costs to repair and maintain tangible property from capitalizing and depreciating these costs to deducting these costs under § 162, and (2) unit of property for determining dispositions of depreciable network assets from using a method other than the functional interdependence test to using the functional interdependence test to determine the units of property.

As stated previously, condition nine of the [Redacted Text] Consent Agreement provides that if any item of property subject to the Form 3115 is public utility property within the meaning of § 168(i)(10), a normalization method of accounting (within the meaning of § 168(i)(9)) must be used for such public utility property. Public utility property (within the meaning of § 168(i)(10)) is a depreciable asset. Consequently, condition nine of the [Redacted Text] Consent Agreement is intended to apply to Taxpayer's public utility property that continues to be depreciated for federal income tax purposes under Taxpayer's new method of accounting for the year of change and subsequent taxable years.

When there is a change in method of accounting to which § 481(a) is applied, income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed by Taxpayer, and income for the year of change and the following taxable years must be determined under Taxpayer's new method of accounting as if the new method had always been used. *See* § 481(a); § 1.481-1(a)(1); and § 2.05(1) of Rev. Proc. 97-27. In other words: (1) Taxpayer's new method of accounting is implemented beginning in the year of change; (2) Taxpayer's old method of accounting used in the taxable years preceding the year of change is not disturbed; and (3) Taxpayer takes into account a § 481(a) adjustment in computing taxable income to offset any consequent omissions or duplications.

Accordingly, for public utility property in service as of the end of the taxable year immediately preceding the year of change ([Redacted Text]), the depreciation-related ADIT existing prior to the year of change for the changes in methods of accounting subject to the [Redacted Text] Consent Agreement does not remain subject to the normalization method of accounting within the meaning of § 168(i)(9) after implementation of the new tax methods of accounting in the year of change and subsequent taxable years.

As stated previously under ruling request 3, condition nine of the [Redacted Text] Consent Agreement is intended to apply to Taxpayer's public utility property that continues to be depreciated for federal income tax purposes under Taxpayer's new method of accounting for the year of change and subsequent taxable years. A repair expense is an item of expense that is deductible under § 162 and for which depreciation is not allowable. Accordingly, the ADIT resulting from the repair-related

§ 481(a) adjustment is not subject to the normalization method of accounting within the meaning of § 168(i)(9).

Similarly, condition nine of the [Redacted Text] Consent Agreement is intended to apply to Taxpayer's public utility property that continues to be depreciated for federal income tax purposes under Taxpayer's new method of accounting for the year of change and subsequent taxable years. A repair expense is an item of expense that is deductible under § 162 and for which depreciation is not allowable. Accordingly, ADIT resulting from expenditures (1) related to an item of property includible in rate base and recoverable as regulatory depreciation expense in the determination of the revenue requirement set in the Surcharge Case and (2) deducted as repairs under § 162 to public utility property within the meaning of § 168(i)(10), or a predecessor provision of the normalization requirements, pursuant to the tax method of accounting for repairs permitted in Taxpayer's Consent Agreement, is not subject to the normalization method of accounting within the meaning of § 168(i)(9) or, as applicable, a predecessor statutory provision.

Regarding ruling request 6, § 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under § 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under § 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under § 167(a). In this case, the transaction involves a replacement or relocation that is not treated as a disposition under Taxpayer's tax method of accounting. The depreciation-related ADIT existing immediately prior to a transaction considered a retirement for regulatory accounting purposes but not treated as a disposition for federal income tax purposes continues to be subject to the normalization requirements because adjusted tax basis is not affected and the § 168(a) depreciation deductions continue.

For ruling request 7, as stated previously under ruling request 3, condition nine of the [Redacted Text] Consent Agreement is intended to apply to Taxpayer's public utility property that continues to be depreciated for federal income tax purposes under Taxpayer's new method of accounting for the year of change and subsequent taxable years. Accordingly, the ADIT resulting from the disposition-related § 481(a) adjustment and related to the restored tax basis of public utility property that was treated as disposed under the old method of accounting but is not treated as disposed under the new method of accounting is subject to the normalization method of accounting within the meaning of § 168(i)(9).

Regarding ruling requests 8, 9, and 11, generally, Taxpayer is arguing that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax during the Surcharge Case test period due to the presence of the NOLC. The normalization requirements pertain only to deferred income taxes for public utility property resulting from the use of accelerated depreciation for tax purposes and the use of straight-line depreciation for establishing cost of service and reflecting the operating results in regulated books of account. Generally, amounts that do not actually defer tax because of the existence of an NOL need to be reflected as offsetting entries to the ADIT account to show the portion of tax losses which did not actually defer tax due to accelerated depreciation.

Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the reserve account for deferred taxes (ADIT), reduces rate base, it is clear that the portion of the net operating loss carryover (NOLC) that is attributable to accelerated depreciation must be taken into account in calculating the amount of the ADIT account balance. Thus, the ADIT asset resulting from the NOLC should be included in rate base, given the inclusion in rate base of the full amount of the ADIT liability resulting from accelerated tax depreciation.

Section 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. The "with or without" methodology suggested by Taxpayer is specifically designed to ensure that the portion of the

NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers.

Taxpayer also raises the issue of the computation of the amount by which depreciation-related Taxpayer's NOLC as of the rate base determination date for the Surcharge Case must be included in rate base. This focuses on whether the NOLC taken into account in the Surcharge Case is limited to depreciation-related book/tax differences related to expenditures reflected in the Surcharge Case or must also reflect the full net increase in depreciation-related NOLC occurring since the rate base determination date of the immediately preceding base rate proceeding. In this case, based on the State B statute, the revenue requirement of a Surcharge Case is limited to the following income tax amounts: ADIT associated with property-related costs for property with rates set by the Surcharge Case and income taxes applicable to the Surcharge Case revenue requirement. The normalization requirements do not require that all incremental NOLC arising since the most recent general rate proceeding must be reflected in an interim (here a Surcharge) proceeding. Instead, the normalization requirements permit an increase in NOLC resulting from non-Surcharge Case public utility property to be disregarded for the Surcharge Case and considered in the next rate proceeding that reflects the depreciation expense and rate base inclusion of the public utility property resulting in the depreciation-related book/tax differences included in the NOLC.

Based on the foregoing, we conclude that:

1) The property otherwise depreciable under § 168(a) and for which cost recovery and return on investment initially occur as part of the Surcharge Case, rather than as part of base rates set in less frequent general rate case proceedings, constitutes public utility property within the meaning of § 168(i)(10).

2) The ADIT amounts used in computing the revenue requirement set in the Surcharge Case with respect to public utility property within the meaning of § 168(i)(10) must comply with the normalization method of accounting within the meaning of § 168(i)(9).

3) For any public utility property within the meaning of § 168(i)(10) of the Code as of the end of the tax year immediately preceding the year of change for the changes in tax method of accounting subject to Taxpayer's Consent Agreement, the depreciation-related ADIT prior to the change in tax method of accounting for repairs and dispositions is not subject to the normalization method of accounting within the meaning of § 168(i)(9) of the Code after implementation of the new tax method of accounting.

4) For any public utility property within the meaning of § 168(i)(10) and subject to Taxpayer's Consent Agreement, the ADIT resulting from the repair-related § 481(a) adjustment is not subject to the normalization method of accounting within the meaning of § 168(i)(9).

5) The ADIT resulting from expenditures (1) related to an item of property includible in rate base and recoverable as regulatory depreciation expense in the determination of the revenue requirement set in the Surcharge Case and (2) deducted as repairs under § 162 to public utility property within the meaning of § 168(i)(10), or a predecessor provision of the normalization requirements, pursuant to the tax method of accounting for repairs permitted in Taxpayer's Consent Agreement, is not subject to the normalization method of accounting within the meaning of § 168(i)(9) or, as applicable, a predecessor statutory provision.

6) The ADIT resulting from book/tax differences related to depreciable method and life for public utility property that exists at the date of a retirement of the property for regulatory accounting purposes in a transaction involving a replacement or relocation that is not treated as a disposition under Taxpayer's tax method of accounting for dispositions permitted in Taxpayer's Consent Agreement remains subject to the normalization method of accounting within the meaning of § 168(i)(9) after the book-only retirement.

7) For any public utility property within the meaning of § 168(i)(10) for which a disposition had been recognized for tax purposes in a tax year prior to the tax year of change for the changes in tax method of accounting subject to Taxpayer's Consent Agreement and for which the taxable gain or loss upon such disposition was reversed as part of the disposition-related § 481(a) adjustment, the ADIT related to the restored tax basis of such public utility property is subject to the normalization method of accounting within the meaning of § 168(i)(9), despite the book-only retirement.

8) In order to comply with the normalization method of accounting within the meaning of § 168(i)(9), the amount of depreciation-related ADIT reducing rate base used to determine the revenue requirement set in the Surcharge Case is limited to the amount of depreciation-related deferred tax expense recovered in rates as of the Surcharge Case rate base determination date.

9) Under the circumstances described, in order to comply with the normalization method of accounting within the meaning of § 168(i)(9), the amount of depreciation-related ADIT reducing rate base used to determine the revenue requirement set in the Surcharge Case must be decreased to reflect a portion of the NOL for the test period for the Surcharge Case which would not have arisen had Taxpayer not reported depreciation-related book/tax differences during the text period for the Surcharge Case and such decrease in depreciation-related ADIT must be an amount that is no less than the amount computed using the With-and-Without Method.

10) Ruling request 10 is moot because we grant ruling 9 in accordance with Taxpayer's analysis.

11) Under the circumstances described above, in order to comply with the normalization method of accounting within the meaning of § 168(i)(9), it is not necessary to decrease

ADIT or otherwise increase rate base for the Surcharge Case by the portion of the NOLC which would not have arisen (or an increase in such NOLC which would not have arisen) had Taxpayer not reported depreciation-related book/tax differences in prior periods or during the test period for the Surcharge Case with respect to public utility property with rates not set by the Surcharge Case.

12) Ruling request 12 is moot because we rule as Taxpayer requests with respect to ruling request 5.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

This ruling is based upon information and representations submitted by Taxpayer and accompanied by penalty of perjury statements executed by an appropriate party. While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representatives.

Sincerely,

Patrick S. Kirwan

Chief, Branch 6

Office of Associate Chief Counsel

(Passthroughs & Special Industries)

Kentucky Power Company NOLC - Total Company Calculation
Net Operating Loss Schedule - Total Company

	Taxable Income/(Loss)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021 Amended Return	12/31/2022	3/31/2023	**NOL Carryforward @ 12-31-17**
2007 As Filed	26,773,624		(26,773,624)																-
2008 As Filed	1,238,699		(1,238,699)																-
2009 As Filed	(79,923,011)		28,012,323	30,366,964	21,543,724														-
2010 As Filed	30,366,964			(30,366,964)															-
2011 As Filed	29,192,737				(21,543,724)	(7,649,013)													-
2011 RAR	56,032					(56,032)													-
2012 As Filed	19,277,355						(19,277,355)												-
2012 RAR	(31,784,955)					7,705,045	24,079,910												-
2013 As Filed	21,088,012						(4,802,555)		(16,285,457)										-
2013 RAR	493,069								(493,069)										-
2014 As Filed	30,249,142								(30,249,142)										-
2014 Amend	51,008								(51,008)										-
2014 RAR	612,080								(612,080)										-
2015 As Filed	(138,371,964)								47,690,756									0	(90,681,208)
2016 As Filed	(11,839,011)																		(11,839,011)
2017 As Filed	(28,876,901)																		(28,876,901)
2018 As Filed	10,685,671																		
2019 As Filed	2,356,998																		
2020 As Filed	(42,427,944)																		
2021 As Filed	(36,697,777)																		
2021 Amended	(7,508,028)																		
12/31/2022 Estimate*	(4,590,652)																		
3/31/2023 Estimate*	9,121,719																		
	(200,457,133)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(131,397,120)

Calculation of NOL Deferred Tax Asset	
NOL Carryforward @ 12-31-17	131,397,120
Tax Rate	21%
NOL DTA @ 12-31-17	**27,593,395**
NOL (Utilization)/Generation: 2018 - 2021	73,591,080
NOL (Utilization)/Generation: 2012 - March 2023	(4,531,067)
Tax Rate	21%
Change in NOL DTA: 2018 - 2022	**14,502,603**
NOL DTA @ 03-31-23	**42,095,998**
Total NOLC Deficient Tax Balance @ 03-31-23	**14,641,550**
Total	**56,737,548**

Calculation of Excess NOL ADFIT		
NOL Carryforward @ 12-31-17	131,397,120	
	21%	
NOL DTA @ 21%	**27,593,395**	
NOL DTA @ 35%	45,988,992	
Protected Deficient NOL ADFIT	**18,395,597**	
Consolidated NOLC Already Recorded:	755,807	DTA 12/31/2017
Amended Return Mvmt:	373,246	
Total Deficient NOL ADFIT to Record as of 12/31/17:	**17,266,544**	
January 2018-March 2022 Deficient Amortization	**(2,238,083)**	
April 2022 - March 2023 Amortization	**(386,911)**	
Total NOLC Deficient Tax Balance as of 3/31/23	**14,641,550**	

*Tax returns not yet finalized.

Kentucky Power Company NOLC - Jurisdictional Amounts
12 Months Ended March 31, 2023

	3/31/2023	Depr Allocator	KY
Consol NOLC	0	0.986000	0
Stand Alone NOLC	42,095,998	0.986000	41,506,654
NOLC 1901001 - DTA	42,095,998		41,506,654

	3/31/2023
NOLC 28201001 Excess KY Adjustment	10,300,444

Kentucky Power Company NOLC Deficient Taxes
Summary of NOLC Adjustment to 2821001

Company	Jurisdiction	Function	Protected / Unprotected	2022 NOL Deficient Taxes Balance	2023 Deficient Tax Amort	2023 NOL Deficient Taxes Balance	3 months of 2023 Deficient Tax Amort	2023 Ended 3/31/2023	9 months April 2022 - March 2023 Deficient Tax Amort	12 months April 2022 - March 2023 Deficient Tax Amort
KYPCO	KY	D	P	4,018,386	(94,504)	3,923,883	(23,626)	3,994,760	(62,124)	(85,750)
KYPCO	KY	G	P	6,338,564	(131,522)	6,207,043	(32,880)	6,305,684	(172,237)	(205,117)
KYPCO	FE	D	P	61,193	(1,439)	59,754	(360)	60,833	(946)	(1,306)
KYPCO	FE	G	P	96,526	(2,003)	94,523	(501)	96,026	(2,623)	(3,124)
KYPCO	FE	T	P	4,206,939	(90,769)	4,116,170	(22,692)	4,184,247	(68,922)	(91,614)
KYPCO	KY	D	U	-	-	-	-	-	-	-
KYPCO	KY	G	U	-	-	-	-	-	-	-
KYPCO	FE	D	U	-	-	-	-	-	-	-
KYPCO	FE	G	U	-	-	-	-	-	-	-
KYPCO	FE	T	U	-	-	-	-	-	-	-
							-	-	-	-
							-	-	-	-
Total				14,721,610	(320,237)	14,401,373	(80,059)	14,641,550	(306,851)	(386,911)
			Sum of KY	10,356,951	(226,026)	10,130,925	(56,506)	**10,300,444**	(234,360)	**(290,867)**

KENTUCKY POWER COMPANY NOLC
TOTAL COMPANY JOURNAL ENTRIES

Calculation of Stand-Alone NOLC - Total Company
Twelve Months Ended March 31, 2023

Description	Account No.	Total Company	
Increase rate base to include the stand-alone Net Operating Loss ("NOL") Deferred Tax Asset ("DTA") and Protected Excess ADIT balance related to the NOL as 12/31/2017, the date of Tax Cuts and Jobs Act ("TCJA"), and decrease Protected Amortization expense due to offsetting protected excess benefit related to the NOL.			
2017 NOLC			
Stand Alone NOLC as of 12.31.2017		(131,397,120)	
AEP Consolidated Group NOLC allocated to the Company as of 12.31.2017		8,064,664	
Stand Alone NOLC Adjustment to Excess ADFIT		(123,332,456)	
2017 - Excess ADFIT adjustment for Stand-Alone NOLC			
Entry to reflect remeasurements of NOL and corresponding deficient deferred taxes			
	2544001	21,856,385	
	2824001	(17,266,544)	
	2821001	17,266,544	
	1904001	(4,589,841)	
	4112001	(17,266,544)	(a)
Amortization of NOLC Deficient Tax - Jan 2018 to March 2022			
Entry to reflect the amortization of the NOLC deficient utilizing ARAM for prior periods	2544001	(2,833,016)	
	4102001	2,238,083	(a)
	2821001	(2,238,083)	
	2824001	2,238,083	
	1904001	594,933	
Amortization of NOLC Deficient Tax - April 2022 - March 2023			
Entry to reflect reduced amortization of Protected Excess for the Six Month Post-Test Period	2544001	(489,760)	
	4102001	386,911	(b)
	2821001	(386,911)	
	2824001	386,911	
	1904001	102,850	
2022 NOLC Adjustment			
Stand Alone NOLC as of 12.31.2017		(131,397,120)	
Taxable Income/(Loss) earned from 2018-2022		(78,181,732)	
Taxable Income/(Loss) earned in January - March 2023		9,121,719	
Stand Alone NOLC as of 12.31.2022		(200,457,133)	
NOLC Deferred Tax Asset at 21%		(42,095,998)	
AEP Consolidated Group NOLC allocated to the Company as of 12.31.2022		-	
NOLC DTA Adjustment		(42,095,998)	
Total Company Stand Alone NOLC DTA as of the Test Period		**(42,095,998)**	
∑(a)+(b) Reduction to Protected Excess ADFIT Liability as of the Test Period		**(14,641,550)**	
Total NOLC DTA Adjustment		**(56,737,548)**	
(b) Increase to deferred tax expense for NOLC deficient amortization as of the Test Period		**386,911**	
Federal and State Gross up Factor (used for illustrative purposes only)		1.2658	

Account Key	
SFAS 109 Excess Deferred FIT Regulatory Liability	2544001
Accumulated Deferred FIT - SFAS 109 Excess - Utility Property	2824001
Accumulated Deferred FIT - Utility Prop	2821001
Accumulated Deferred FIT - FAS 109 Excess	1904001
Provision for Deferred Income Tax Utility Operations - FIT	410.1/411.1
Provision for Deferred Income Tax Other Income & Deductions - FIT	410.2/411.2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2023-00159

DIRECT TESTIMONY OF

LERAH M. KAHN

ON BEHALF OF KENTUCKY POWER COMPANY

DIRECT TESTIMONY OF
LERAH M. KAHN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00XXX

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EXHIBITS

DIRECT TESTIMONY OF
LERAH M. KAHN ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Lerah M. Kahn. My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101. My position is Manager, Regulatory Services, Kentucky Power Company ("Kentucky Power" or the "Company").

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.

A. In 2009, I earned a Bachelor of Arts degree in History from the University of Guelph in Guelph, Ontario, Canada. Additionally, in 2010 I received a Paralegal diploma from Algonquin Careers Academy in Mississauga, Ontario, Canada.

From 2013 through 2018 I worked at Sogefi Group Inc., a global supplier for the automotive industry, as a material planner and accounting specialist. I accepted the position of Regulatory Consultant with Kentucky Power Company in July 2018 and I was promoted to my current position as Manager, Regulatory Services in February 2023.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH KENTUCKY POWER?

A. As Manager, Regulatory Services I am responsible for the supervision and direction of Kentucky Power's Regulatory Services Department, which has responsibility for all rate and regulatory matters involving the Company.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before this Commission in Case No. 2019-00389 (application for approval of the Company's 2019 Environmental Compliance Plan ("ECP")), Case No. 2020-00133 (Commission's examination of the Company's Environmental Surcharge mechanism for the two-year billing period ending June 30, 2019), Case No. 2020-00174 (the Company's most recent base rate case), Case No. 2021-00004 (the Company's current ECP), and 2022-00387 (application for a special contract).

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support an update to the Company's base revenue requirement for its environmental surcharge. In addition, I support the following adjustments to test year revenues and operating expenses:

- An adjustment to remove the capital cost of the Mitchell flue gas desulfurization ("FGD"), FGD-associated consumable inventories, and CCR CWIP from rate base and capitalization;
- An adjustment to remove Mitchell FGD expenses from test year expenses;

- An adjustment to remove Rockport and Mitchell FGD revenues and to synchronize other environmental surcharge revenues and expenses during the test year;

- An adjustment to recover rate case expenses;

- An adjustment to recover replacement capacity due to the expiration of the Rockport Unit Power Agreement; and

- Treatment of remaining unprotected excess accumulated deferred federal income taxes ("ADFIT");

I provided the adjustments to revenues and operating expenses and rate base to Company Witness Walsh to include in the computation of the Company's jurisdictional revenue requirement. I provided the adjustments to capitalization to Company Witness Walsh to present in Section V, Schedule 3.

Finally, I describe certain proposed changes to Kentucky Power's tariffs.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I have prepared the following exhibits:

EXHIBIT	DESCRIPTION
Exhibit LMK-1	Adjusted Environmental Base
Exhibit LMK-2	Proposed Environmental Surcharge Tariff ("Tariff E.S.")
Exhibit LMK-3	Revised Monthly "ES" (Environmental Surcharge) Calculation Forms
Exhibit LMK-4	Illustration of ES Forms' Reorganization
Exhibit LMK-5	Updated Environmental Compliance Plan ("ECP")
Exhibit LMK-6	Replacement Capacity Costs
Exhibit LMK-7	Tariff Book Focused Redlines

IV. BASE ENVIRONMENTAL REVENUE REQUIREMENT

Q. PLEASE EXPLAIN GENERALLY HOW KENTUCKY POWER RECOVERS ITS ENVIRONMENTAL COSTS.

A. Kentucky Power recovers the costs of the authorized environmental projects included in its ECP through a combination of base rates and the environmental surcharge. The authorized projects included in the Company's ECP, which was most recently updated in Case No. 2021-00004, are those projects necessary for the Company to comply with the Federal Clean Air Act and federal, state, and local requirements applicable to coal combustion wastes and by-products from coal-fired generation facilities ("Environmental Requirements"). Tariff E.S. identifies, for each month, the amount of environmental costs included in base rates. Each month, the Company calculates the total costs associated with the approved environmental projects in its ECP. The monthly total cost includes expenses and credits related to the operation of approved projects, a return on the environmental rate base including construction work in progress ("CWIP")[1], a return on the Company's emission allowance inventory, emission allowance expenses, expense to amortize the regulatory asset authorized by the Commission in Case No. 2021-00004[2] for prudently incurred Effluent Limitation Guidelines ("ELG") costs[3], costs associated with the consumption of consumables,

[1] See Order, Application Of Kentucky Power Company For Approval Of A Certificate Of Public Convenience and Necssity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets, Case No. 2021-00004, at 24-25 (Ky. P.S.C. July 15, 2021).

[2] See Order, Application Of Kentucky Power Company For Approval Of A Certificate Of Public Convenience and Necssity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets, Case No. 2021-00004, at 12 (Ky. P.S.C. May 3, 2022).

[3] Over a two-year period beginning with July 2022 billing and concluding with June 2024 billing.

depreciation, and property taxes for the Mitchell Plant. The Company then compares the total monthly environmental costs to the amount of environmental costs included in its base rates. If the total monthly environmental costs exceed the monthly base rate amount, customers are charged the difference through the environmental surcharge. If the total monthly environmental costs are less than the monthly base rate amount, customers are credited the difference through the environmental surcharge.

Q. WERE THERE ANY MAJOR CHANGES DURING THE TEST YEAR TO ITEMS INCLUDED WITHIN THE MONTHLY TOTAL ENVIRONMENTAL COSTS?

A. Yes. Kentucky Power was previously a party to a FERC-approved unit power agreement ("Rockport UPA"). The Rockport UPA provided Kentucky Power with the contractual right to receive 30 percent of AEP Generating's 50 percent share of the generation output from Rockport Unit 1 and Rockport Unit 2 and obligated it to 30 percent of AEP Generating's Rockport Unit 1 and Rockport Unit 2 costs. The Rockport UPA expired on December 8, 2022. Accordingly, the Company's environmental surcharge filed January 23, 2023, for the month of December 2022, was the last month to include Rockport costs within the total environmental costs.[4]

Q. PLEASE EXPLAIN HOW THE MONTHLY ENVIRONMENTAL BASE REVENUE REQUIREMENT WAS CALCULATED.

A. The test year monthly environmental base revenue requirement was calculated by identifying Kentucky Power's share of the costs associated with Mitchell Non-FGD

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[4] Rockport costs for the month of December 2022 were prorated.

environmental projects in each month of the test year and then included gains on allowances in each month. Exhibit LMK-1 provides the monthly environmental base rate amounts.

The current monthly environmental base rate amount includes costs for the Rockport Plant. The proposed base environmental revenue requirement provided in Exhibit LMK-1 does not include costs for the Rockport Plant due to the expiration of the Rockport UPA on December 8, 2022 discussed above.

Q. WERE THE COSTS FOR ALL OF THE COMPANY'S ECP PROJECTS INCLUDED IN THE CALCULATION OF THE MONTHLY ENVIRONMENTAL BASE REVENUE REQUIREMENT CALCULATION?

A. No. To properly identify the base level of environmental project costs, only costs associated with projects that were in-service during the test year were included in the base revenue requirement calculation. The work required to comply with the CCR rule ("Project 22"), wastewater ponds and associated work in connection with the wastewater ponds, was not in service during the test year ended March 31, 2023. The Commission approved Project 22 in the Company's 2021 ECP, in Case No. 2021-00004 Order dated July 15, 2021. Project 22 was originally estimated to go into service November 2023. The current estimated in-service date is October 2024. On January 23, 2023 the Company filed into post-case correspondence of Case No. 2021-00004 an update on the delay and then on June 9, 2023 filed additional information around cost estimate changes resulting from the delay. Accordingly, the costs associated with

Project 22 will be, and currently are for a return on CWIP, recovered exclusively through Tariff E.S.[5]

Also excluded from the environmental base revenue requirement are:

- Monthly installments of the ELG regulatory asset amortization;
- Costs associated with Rockport (discussed above); and
- Costs associated with the Mitchell FGD (discussed below).

V. COSTS ASSOCIATED WITH THE MITCHELL FGD

Q. WHAT IS THE COMPANY PROPOSING WITH REGARDS TO MITCHELL FGD COSTS?

A. The Company is proposing to continue excluding Mitchell FGD costs from the base environmental costs consistent with paragraph 6 of the Commission-approved Stipulation and Settlement Agreement in Case No. 2012-00578.

Q. DID YOU PREPARE ANY RATE CASE ADJUSTMENTS TO REMOVE KENTUCKY POWER'S SHARE OF THE COSTS ASSOCIATED WITH THE MITCHELL FGD FROM THE TEST YEAR DATA AND THE PROPOSED ENVIRONMENTAL RATE BASE AMOUNTS?

A. Yes, adjustments W03 and W04 within Section V, Exhibit 2. Adjustment W03 removes Mitchell FGD operating and maintenance expenses from the test year. The Mitchell FGD operating expense adjustment includes costs associated with gypsum disposal, limestone, lime hydrate, and polymer in addition to the depreciation, maintenance, and property tax expenses. After allocating the FGD expenses to retail

[5] A return on CWIP ceases once the new assets are placed in service.

customers as described in the Commission's March 31, 2003 Order in Case No. 2002-00169, this adjustment reduces test year operating expenses by a total of $12,222,750.

Adjustment W04 removes the rate base amount of the Mitchell FGD from the test year. The rate base deduction was calculated by removing the accumulated depreciation and accumulated deferred income tax amounts from the FGD electric plant in service amount. This adjustment also removes the consumable inventory that is used in conjunction with the FGD. The production demand allocation factor was then applied to the rate base amount and the production demand energy allocation factor was applied to the consumable inventory. This results in a reduction of test-year base rate amount of $136,650,071.

Q. DOES ADJUSTMENT W04 REMOVE ANY NON-FGD COMPONENTS?

A. Yes. CWIP associated with Project 22 is also removed through adjustment W04. The production demand energy allocation factor was applied to the CWIP amount. This results in a reduction of test-year base rate amount of $11,100,396.

Q. WHAT DEPRECIATION RATE WAS USED TO CALCULATE THE DEPRECIATION EXPENSE FOR THE MITCHELL FGD?

A. The Company uses a 2.96% depreciation rate for projects within account 312 – Boiler Plant Equipment. This is the depreciation rate utilized in developing the depreciation expense for the Mitchell FGD and is the same depreciation rate approved by the Commission in Case No. 2017-00179.

VI. WEIGHTED AVERAGE COST OF CAPITAL

Q. WHAT WEIGHTED AVERAGE COST OF CAPITAL ("WACC") DID KENTUCKY POWER USE IN CALCULATING THE REVENUE REQUIREMENT FOR ENVIRONMENTAL PROJECTS, INCLUDING THE MITCHELL FGD?

A. Kentucky Power used a 6.93% WACC. The WACC is calculated in Section V, Schedule 2, Page 1, of the Application and described in the testimony of Company Witness Messner. In calculating the WACC for environmental projects, Kentucky Power used the 9.90% rate of return on equity proposed by the Company in this case. The basis for using a 9.90% rate of equity is included in the testimony of Company Witness Wiseman. Additionally, Company Witness McKenzie discusses that the ROE should not be further reduced for single-issue recovery mechanisms such as the environmental surcharge.

VII. GROSS REVENUE CONVERSION FACTOR

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS GROSS REVENUE CONVERSION FACTOR ("GRCF")?

A. Yes. The revised factor can be found in Section V, Schedule 2, Page 2, of the Application and shown on Form 3.20 of Exhibit LMK-3.

VIII. CHANGES TO TARIFF E.S. AND THE ECP

Q. HAS THE COMPANY REVISED TARIFF E.S. TO REFLECT THE CHANGES PROPOSED ABOVE?

A. Yes. A copy of the Company's proposed Tariff E.S., with markups indicating changes from the current Tariff E.S., is included as Exhibit LMK-2.

Q. HAS THE COMPANY ALSO REVISED THE ENVIRONMENTAL SURCHARGE FORMS USED FOR ITS MONTHLY FILING?

A. Yes. A copy of the Company's revised environmental surcharge forms is included as Exhibit LMK-3. The proposed changes are threefold:

- Removal of Rockport related forms in their entirety (3.20 and 3.21) and references to Rockport throughout the other forms where applicable;

- Reformatting and reorganization of the Forms to provide easier processing and understanding of the correlation between Forms. Exhibit LMK-4 provides an illustration of the new organization; and,

- Updates for the following proposals:
    - Form 3.10 – updated WACC (line 18 and line 19) and gross-up factor (line 47);
    - Form 3.20 – revised to align with Section V, Schedule 2, Page 1 of the Application;
    - Form 3.50 – revised cash working capital calculation consistent with the Section V (tab "CWC", line 5); and,
    - Form 6.00 – remove "PPA Revenues" and "ATR Revenues" columns. As the PPA rate changed to a per-kWh rate (from percent of revenues) and the ATR rate has ceased in accordance with the January 18, 2018 Order in Case No. 2017-00179. Any amounts being captured in this form for these two items relate to rebillings which, due to the time passed from the above, is nominal.

Q. WAS THE COMPANY'S ECP ALSO UPDATED?

A. Yes. A copy of the Company's updated ECP is attached as Exhibit LMK-5. This is an administrative update to either completely remove projects related to Rockport or references to Rockport where applicable. There are no new projects being added.

IX. RATE CASE ADJUSTMENTS

Q. DID YOU PREPARE ANY ADJUSTMENTS BESIDES THE ENVIRONMENTAL ADJUSTMENTS W03 AND W04 DESCRIBED ABOVE?

A. Yes. I prepared adjustments to test year revenue amounts to remove Rockport and FGD-related revenues and deferrals (W05), an adjustment to recover rate case expense (W18), and an adjustment to update test-year levels of replacement capacity costs due to the expiration of the Rockport UPA (W56). I have provided the adjustments to revenues and operating expenses and rate base to Company Witness Walsh to include in the computation of the Company's jurisdictional revenue requirement. I have provided the adjustments to capitalization to Company Witness Walsh to present in Section V, Schedule 3.

Environmental Surcharge Revenue (Section V, Exhibit 2, W05)

Q. PLEASE EXPLAIN THE ENVIRONMENTAL SURCHARGE REVENUE ADJUSTMENT.

A. Because costs associated with Rockport and the Mitchell FGD have been removed from cost of service[6], any associated revenues must also be removed. This adjustment is

[6] See adjustments W03 and W04 supported by Company Witness Kahn and adjustment W47 supported by Company Witness Whitney.

calculated by first determining the total test year revenues associated with the Company's ECP. This calculation is made by adding the total amount of environmental surcharge revenue for the test year to the test year annual environmental base revenue amount. The Company next deducted the going-forward annual environmental base revenue amount as set forth in Exhibit LMK-1. This calculation results in a $46,964,573 reduction to base rates that simultaneously removes Rockport and Mitchell FGD revenues and synchronizes the environmental compliance costs and revenues.

In addition to the removal of Rockport and Mitchell FGD revenues, adjustment W05 adds $3,573,270 of deferred environmental surcharge amounts. The net result of this adjustment is a $43,391,303 reduction to base rates. Removing revenue or expense related to over-/under-recovery ensures that rider-related amounts are not in the determination of the Company's base rates. Company Witness Whitney discusses the basis for over-/under-recovery accounting.

Rate Case Expense
(Section V, Exhibit 2, W18)

Q. WHAT IS THE RATE CASE EXPENSE ADJUSTMENT?

A. The Company is permitted to recover its reasonable expenses for the preparation and litigation of this rate case proceeding, including reasonable consulting and legal expenses. The Company estimates a total rate case expense of $1,006,000. This amount includes the estimated cost for an abbreviated notice which is expected to result in a savings of $401,000 for customers.[7] The estimated expenses should be amortized over three years, with rate case expenses incurred during the test year ($55,923) removed, at a rate of $279,410.

Replacement Capacity
(Section V, Exhibit 2, W56)

Q. PLEASE DESCRIBE THE ADJUSTMENT TO INCREASE THE AMOUNT OF REPLACEMENT CAPACITY COSTS WITHIN THE TEST-YEAR.

A. Due to the expiration of the Rockport UPA, Kentucky Power:

- Estimates it will require 70.2 MW of capacity through the PJM 2023/2024 planning year ending May 31, 2024 at the Base Residual Action Clearing Price of $34.13 per MW-day. These capacity purchases will be made through the AEP East Power Coordination Agreement ("PCA") between Appalachian Power Company, Indiana Michigan Power Company, Wheeling Power Company, and Kentucky Power Company.

- Has entered into a bilateral market capacity purchase agreement for 80 MW at $54 per MW-day for year ending May 31, 2025 (PJM 2024/2025 planning year).

The above translates to an estimated cost of $1,288,661 for replacement capacity due to the Rockport UPA expiration in calendar year 2024. Exhibit LMK-6 provides the monthly actual (December 9, 2022 through March 2023) and estimated (through May 2025) replacement capacity costs. The Company anticipates the approved rates in this proceeding to go into effect January 1, 2024. Accordingly, adjustment W56 seeks to bring the amount of replacement capacity costs within the test year to the estimated calendar year 2024 level. Utilizing the production demand allocation factor, this adjustment results in an addition to the test-year of $413,681.

[7] The Commission approved the Company's request to utilize an abbreviated notice in its June 22, 2023 Order in Case No. 2023-00159.

Because capacity purchases are recoverable through Tariff Purchase Power Adjustment (P.P.A.), this adjustment will also represent a portion of the base amount for element "N" in the PPA formula.[8]

X. CHANGES TO TARIFF SHEETS

Q. PLEASE PROVIDE AN OVERVIEW OF THE CHANGES BEING PROPOSED FOR THE COMPANY'S TARIFFS.

A. Kentucky Power is proposing several new tariffs and modifications to existing tariffs in this case. Figure LMK-1 provides an overview of these proposals.

[8] N = The annual cost of power purchased by the Company through new Purchase Power Agreements and purchased power expense from avoided cost payments to net metering customers under tariff N.M.S.II. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.

Figure LMK-1

Tariff	Status	Proposal	Supported By Company Witness(es)
Distribution Reliability Rider (DRR)	New	New capital rider to address major reliability drivers	West; Phillips; Spaeth
Securitization Financing Rider (SFR)	New	New rider to recover securitization financing costs	West; Spaeth
Seasonal Rate Provision	New	Optional provision for residential customers to provide winter bill relief	Spaeth
Purchased Power Adjustment (PPA)	Existing	Remove PJM LSE OATT tracking; Solar garden	West; Vaughan
Fuel Adjustment Clause (FAC)	Existing	Incorporate financial power hedging program	Vaughan
Residential Energy Assistance (REA)	Existing	Increase surcharge from \$0.30 to \$0.40	Cobern
Terms and Conditions (T&C's)	Existing	Change due date from 15 to 21 days.	Cobern
Federal Tax Cut (FTC)	Existing	Change name to Federal Tax Change; Remove excess unprotected ADFIT; Over/under related to unprotected excess ADFIT; Add CAMT; Annual filing	Schlessman; Spaeth; Kahn
Environmental Surcharge (ES)	Existing	Environmental base revenue requirement; Remove references to Rockport; Update ROE	Kahn
Non-Utility Generator (NUG)	Existing	Close to new customers; Eliminate Commissioning and Startup Power provisions	Kahn
Outdoor Lighting (OL) and Street Lighting (SL)	Existing	Language that lighting location must be reasonably accessible	Kahn
Franchise Tariff (FT)	Existing	Rename to City's Franchise Fee	Kahn
Reformat and Reorganization	N/A	N/A	Kahn

As noted in the summary above, Company Witness Schlessman and I sponsor the proposed amendments to Tariff F.T.C.

Q. PLEASE DISCUSS THE CURRENT AMORTIZATION PERIOD USED FOR UNPROTECTED EXCESS ADFIT IN TARIFF F.T.C.

A. In Case No. 2020-00174, Order dated January 13, 2021, the Commission agreed with the Company's proposal to accelerate the return of unprotected excess ADFIT to mitigate the rate impact of that case; however, found a three-year amortization period through Tariff F.T.C. to be appropriate. In accordance with that directive, all unprotected excess ADFIT will be fully amortized and returned to customers prior to the rates proposed in this case going into effect.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO TREAT UNPROTECTED EXCESS ADFIT.

A. As noted above, unprotected excess ADFIT will be fully returned to customers and thus no longer be a component of Tariff F.T.C. The Company proposes to recover or credit any remaining protected excess ADFIT through its annual Tariff F.T.C. update discussed further below.

Generation and distribution related protected excess ADFIT will continue to be returned through Tariff F.T.C. at a fixed level.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO TARIFF F.T.C.?

A. Yes, the Company also proposes to recover the Corporate Alternative Minimum Tax ("CAMT") discussed in detail by Company Witness Schlessman through Tariff F.T.C.

Additionally, the Company believes a name change from "Federal Tax Cut" to "Federal Tax Change" will better align with and help customers better understand the various elements included in the tariff. A copy of the repurposed and revised Tariff along with the workpapers for the calculated rates are provided supported by Company Witness Spaeth.

Q. WHAT IS THE COMPANY PROPOSING WITH REGARD TO ITS ANNUAL RATE UPDATE FOR TARIFF F.T.C.?

A. The Company proposes to file its annual rate update and corresponding Tariff by October 15th each year to go into effect with December billing. Because Federal tax returns are due annually by September 15th this will allow the Company time to include the actual CAMT amount in its annual update. For illustration, the first annual update (to be filed October 2024) will utilize the actual 2023 CAMT amount.

Q. WHY IS THE COMPANY PROPOSING TO CONTINUE USE OF TARIFF F.T.C.?

A. As discussed by Company Witness Schlessman, protected excess ADFIT is a fixed amount. Accordingly, a tracking mechanism ensures that the Company does not run afoul and risk a normalization violation.

In regards to CAMT, it is currently difficult to predict the amount that will need to be recovered as it is a new tax. This is discussed further by Company Witness Schlessman as well. Nonetheless, a tracking mechanism ensures that customers pay no more or less for CAMT.

Q. IS THE COMPANY PROPOSING ANY MINOR MODIFICATIONS TO ITS EXISTING TARIFFS IN THIS PROCEEDING?

A. Yes. In addition to the rate changes sought in this proceeding, the Company is proposing a number of textual changes, formatting changes and reorganization to its current tariffs. My testimony does not address minor text changes that clarify existing language or that are intended to conform the tariff to other approved tariffs.

Q. WHAT OTHER SUBSTANTIVE CHANGES TO THE TARIFF BOOK ARE YOU SUPPORTING?

A. I am sponsoring changes to the Company's Non-Utility Generator Tariff, Outdoor Lighting and Street Lighting Tariffs, and Franchise Fee Tariff. Additionally, I support a general reformat and reorganization to the Company's tariff book.

i. Non-Utility Generator Tariff Changes

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE NON-UTILITY GENERATOR ("NUG") TARIFF.

A. The Company's request in this proceeding is the same as that in 2020-00174: to close NUG tariff to new customers as of January 1, 2024 and eliminate the commissioning and startup power provisions of the tariff as they are un-used by the single customer taking service under tariff NUG. Any new non-utility generator's load requirements would be served under the Company's standard industrial tariff.

Q. WHY WAS THIS PROPOSAL DENIED IN THE 2020-00174 PROCEEDING?

A. The Company's request was denied due to pending litigation at the Kentucky Court of Appeals regarding this tariff. Since 2020, that litigation has concluded in Kentucky Power's favor.

Q. IS THERE ANY PENDING LITIGATION AROUND THIS TARIFF CURRENTLY?

A. No.

Q. WHY IS THE COMPANY PROPOSING THIS CHANGE?

A. The special tariff was first introduced in 2001 at a time when Non-Utility Generators were a relatively new concept. Further, at that time the Company was not a member of a regional transmission organization. Only one customer has taken service under the tariff in the last two decades. Much has changed since 2001 and the Company's experience is that a special tariff is no longer needed.

The commissioning power provision is duplicative of the Company's Tariff T.S. and terms and conditions of service. The startup power provision was designed to meet anticipated needs not adequately served by the Company's other tariffs has proven to be unneeded.

ii. Lighting Location Must be Reasonably Accessible

Q. PLEASE DESCRIBE THE PROPOSED LANGUAGE ADDITION TO TARIFFS OL AND SL AROUND TRUCK ACCESSIBILITY.

A. The additional language states that the requested lighting location must be reasonably accessible by the Company's trucks. Addition of this language ensures that the Company's personnel is operating safely and without harm to its or its customers property.

iii. Franchise Tariff Rename

Q. PLEASE EXPLAIN WHY THE COMPANY IS PROPOSING TO CHANGE THE NAME OF TARIFF

A. The name change is aimed at providing clarity to customers.

iv. Reformat and Reorganizaiton

Q. WHY IS THE COMPANY PROPOSING TO REFORMAT AND REORGANIZE ITS TARIFF SHEETS?

A. The reformatting and reorganization of the tariff book is focused at making it easier to to read and understand. Further this approach is more consistent with other Kentucky investor-owned utilities. For illustration, currently the optional offerings to standard rate schedules and adjustment clauses are intermingled. This back-and-forth is confusing and unnecessary to a reader. Accordingly, the proposed tariff reorganization groups by: Standard Offerings (Section 2 through Section 13), Optional Services to Standard Rate Schedules (Section 14 through Section 25, and Adjustment Clauses (Section 26 through Section 39).

Q. HAS THE COMPANY PROVIDED NEW TARIFF SHEETS AND REVISED TARIFF SHEETS IN THE MANNER REQUIRED BY 807 KAR 5:001, SECTION 16(1)(b)(3) AND 807 KAR 5:001, SECTION 16(1)(b)(4)?

A. Yes. Please see Section II – Exhibit D for the clean tariff book and Exhibit E for the tariff book in comparative form, side-by-side. Additionally, Exhibit LMK-7 provides a redlined version of the tariff book only for those text edits which are substantive, excluding formatting changes. For instance, due to the elimination of dead space there is a significant shift in text. Thus, text denoting what was being continued from a prior page changed accordingly. Such edits, along with formatting, were not considered substantive for the purposes of this Exhibit.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?

A. Yes, it does.

VERIFICATION

The undersigned, Lerah M. Kahn, being duly sworn, deposes and says she is the Regulatory Case Manager for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of her information, knowledge, and belief after reasonable inquiry.

Lerah Kahn

Lerah M. Kahn

Commonwealth of Kentucky)
) Case No. 2023-00159
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lerah M. Kahn, on June 26, 2023.

Scott E. Bishop

Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110

Kentucky Power Company
Environmental Base Revenue Requirement (BRR)

Month / Year	Mitchell Non-FGD		Gain or Loss on Sale of Allowances		Adjusted Environmental Base	
(1)	(2)		(3)		(4) =(2)-(3)	
Apr-22	$	2,519,828	$	-	$	2,519,828
May-22	$	2,654,468	$	140,184	$	2,514,284
Jun-22	$	2,644,974	$	-	$	2,644,974
Jul-22	$	2,594,563	$	-	$	2,594,563
Aug-22	$	2,741,097	$	-	$	2,741,097
Sep-22	$	2,508,995	$	-	$	2,508,995
Oct-22	$	2,376,639	$	-	$	2,376,639
Nov-22	$	2,423,992	$	-	$	2,423,992
Dec-22	$	2,597,739	$	-	$	2,597,739
Jan-23	$	3,022,418	$	-	$	3,022,418
Feb-23	$	2,558,332	$	-	$	2,558,332
Mar-23	$	2,621,611	$	-	$	2,621,611
Total	$	31,264,656	$	140,184	$	31,124,472

Tariff E.S.
(Environmental Surcharge)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L. D

Rate
The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 2 below and in the current period as provided in Paragraph 3 below.

The retail share of the revenue requirement will be allocated between residential and non-residential retail customers based upon their respective total revenues during the previous calendar year. The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

The revenues to which the residential Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Residential Energy Assistance, Purchase Power Adjustment, and Distribution Reliability Rider. TDN

The revenues to which the all other customer Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Kentucky Economic Development Surcharge, Purchase Power TD
Adjustment, and Distribution Reliability Rider. N

1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

Where:	E(m)	=	CRR-BRR
	CRR	=	Current Period Revenue Requirement for the Expense Month.
	BRR	=	Base Period Revenue Requirement.

2. Base Period Revenue Requirement, BRR T

BRR = The Following Monthly Amounts:

Billing Month		Base Net Environmental Costs
January	$	3,022,418
February		2,558,332
March		2,621,611
April		2,519,828
May		2,514,284
June		2,644,974
July		2,594,563
August		2,741,097
September		2,508,995
October		2,376,639
November		2,423,992
December	$	2,597,739
	$	31,124,472

R

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020.

Continued on Sheet 32-2

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff E.S. Continued T
(Environmental Surcharge)

3. Current Period Revenue Requirement, CRR T
$CRR=[((RB_{KP(c)})(ROR_{KP(c)})/12) + OE_{KP(c)} - AS]$ D

Where:

$RB_{KP(c)}$	=	Environmental Compliance Rate Base for Mitchell.
$ROR_{KP(c)}$	=	Annual Rate of Return on Mitchell Environmental Compliance Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
$OE_{KP(c)}$	=	Monthly Pollution Control Operating Expenses for Mitchell. D
AS	=	Net proceeds from the sale of Title IV and CSAPR SO 2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt.

"KP(C)" identifies components from Mitchell Units – Current Period. D

The Environmental Compliance Rate Base for Kentucky Power reflects the current cost associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. The Environmental Compliance Rate Base for Kentucky Power should also include construction work in progress until assets are placed in service. The Operating Expenses for Kentucky Power reflects the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. D D

The Rate of Return for Kentucky Power is 9.90% rate of return on equity as authorized by the Commission in its Order Dated XXXX XX, 20XX, Case No. 2023-00159. I D

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

Continued on Sheet 32-3

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff E.S. Continued
(Environmental Surcharge)

T

4. Revenue Allocation T

$$\text{Residential Allocation RA(m)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(m) = the expense month.
(b) = the most recent calendar year revenues

5. Environmental Surcharge Factor

$$\text{Residential Monthly Environmental Surcharge Factor} \quad \frac{\text{Net KY Retail E(m)} \; * \; \text{RA(m)}}{\text{KY RR(m)}}$$

$$\text{All Other Monthly Environmental Surcharge Factor} \quad \frac{\text{Net KY Retail E(m)} \; * \; \text{AO(m)}}{\text{KY OR(m)- KY OF(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

RR(m) = Average Kentucky Residential Retail Revenues for the Preceding Twelve Month Period

OR(m) = Average Kentucky All Other Classes Retail Revenues for the Preceding Twelve Month Period

OF(m) = Average Kentucky All Other Classes Fuel Revenues for the Preceding Twelve Month Period.

Continued on Sheet 32-4

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff E.S. Continued (Environmental Surcharge) T

6. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows: T

   Total Company:
   - return on Title IV and CSAPR SO_2 allowance inventory
   - over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge
   - costs associated with any Commission's consultant approved by the Commission
   - costs associated with the consumption of Title IV and CSAPR SO_2 allowances
   - costs associated with the consumption of NO_x allowances
   - return on NO_x allowance inventory
   - costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)
   - costs associated with consumables used in conjunction with approved environmental projects.
   - return on inventories of consumables used in conjunction with approved environmental projects.
   - return on environmental compliance rate base including construction work in progress.
   - Monthly expense to amortize the $1,446,998.35 regulatory asset for prudently incurred ELG (Effluent Limitation Guidelines) project costs over a two-year period to begin with July 2022 billing and conclude with June 2024 billing. D

   The Company's share of costs associated with the following environmental equipment at the Mitchell Plant:
   - Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
   - Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
   - Air Emission Fees
   - Precipitator Modifications and Upgrades
   - Coal Combustion Waste Landfill
   - Bottom Ash and Fly Ash Handling
   - Mercury Monitoring (MATS)
   - Dry Fly Ash Handling Conversion
   - Wastewater Ponds (for the Mitchell CCR compliance project) with depreciation expense calculated using a 20 percent depreciation rate approved by the Commission's July 15, 2021 and May 3, 2022 Orders in Case No. 2021-00004.

7. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 1.00 - Summary

Month Ended: **X**

Residential Environmental Surcharge Factor	=	X / X	=	X
All Other Classes Environmental Surcharge	=	X / X	=	X

Effective Date for Billing: X

Submitted by: ____________________
(Signature)

Title: X

Date Submitted: X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 1.10 - Calculation of E(m) and Surcharge Factors

1	CRR from ES FORM 1.20	X	
2	BRR from ES FORM 1.10	X	
3	Mitchell FGD Expenses (E.S. Form 3.13)	X	
4	E(m) (Line 1 - Line 2 + Line 3)	X	
5	Kentucky Retail Jurisdictional Allocation Factor, from ES FORM 3.30, Schedule of Revenues	X	
6	KY Retail E(m) (Line 4 * Line 5)	X	
7	Under/ (Over) Collection, ES Form 3.30	X	
8	Net KY Retail E(m) (Line 6 + Line 7)	X	
	SURCHARGE FACTORS	**Residential**	**All Other Classifications**
9	Allocation Factors, % of revenue during previous Calendar Year	X	X
10	Current Month's Allocation E(m) (Line 8* Line 9)	X	X
10A	Levelized CCR CWIP	X	X
10B	Current Month's Total	X	X
11	Kentucky Residential Revenues/All Other Non-Fuel Revenues	X	X
12	Surcharge Factors (Line 10/Line 11)	X	X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 2.00 - Monthly Base Environmental Revenue Requirement

Billing Month	**Base Environmental Costs**
January	X
February	X
March	X
April	X
May	X
June	X
July	X
August	X
September	X
October	X
November	X
December	X
TOTAL	**X**

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.00 - Calculation of Current Environmental Revenue Requirement

Line No.	COMPONENTS		
1	**First Component:** Mitchell Non-FGD expenses (Form 3.10)		X
2	**Second Component:** Net Proceeds from Emission Allowances Sales		
	a) CAIR SO2 - EPA Auction Proceeds received during Expense Month	X	
	b) CSAPR SO2 - Net Gain or (Loss) from Allowance Sales, received during Expense Month	X	
	Total Net Proceeds from SO2 Allowances	X	
	c) NOx - EPA Auction Proceeds, received during Expense Month	X	
	d) NOx - Net Gain or (Loss) from NOx Allowances Sales, received during Expense Month	X	
	Total Net Proceeds from NOx Allowances	X	
	Total Net Gain or (Loss) from Emission Allowance Sales	------------------	X ------------------
3	Total Current Period Revenue Requirement, CRR Recorded on ES FORM 1.10. (Line 1 - Line 2)		X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.10 - Mitchell Environmental Costs

Ln. No.	Cost Component		Non-FGD Costs	FGD Costs	Total Costs
1	Utility Plant at Original Cost		X	X	X
2	Less Accumulated Depreciation		X	X	X
3	Less Accumulated Deferred Income Tax		X	X	X
4	Net Utility Plant		**X**	**X**	**X**
5	*SO2 Emission Allowance Inventory		X	X	X
6	*CSAPR S02 Emission Allowance Inventory		X	X	X
7	*CSAPR NOx Emission Allowance Inventory (Seasonal)		X	X	X
8	*CSAPR AN Emission Allowance Inventory (Annual)		X	X	X
9	Limestone Inventory (1540006)		X	X	X
10	Urea Inventory (1540012)		X	X	X
11	Limestone In-Transit Inventory (1540022)		X	X	X
12	Urea In-Transit Inventory (1540023)		X	X	X
13	Construction Work in Progress (CWIP)		X	X	X
14	Cash Working Capital Allowance		X	X	X
15	Non-FGD Rate Base as of 3/31/2023		X	X	X
16	Additional Non-FGD Rate Base Post 3/31/2023		X	X	X
17	**Total Rate Base**		**X**	**X**	**X**
18	***WACC for Non-FGD Rate Base as of 3/31/2023	8.35%	X		X
19	***WACC for FGD and Non-FGD Additions to 3/31/2023 Rate Base	8.35%	X	X	X
20	Monthly Return for Non-FGD Rate Base as of 3/31/2023		X		
21	Monthly Return for FGD and Non-FGD Additions to 3/31/2023 Rate Base		X	X	X
22	Monthly Disposal (5010000)		X	X	X
23	Monthly Fly Ash Sales (5010012)		X	X	X
24	Monthly Urea Expense (5020002)		X	X	X
25	Monthly Trona Expense (5020003)		X	X	X
26	Monthly Lime Stone Expense (5020004)		X	X	X
27	Monthly Polymer Expense (5020005)		X	X	X
28	Monthly Lime Hydrate Expense (5020007)		X	X	X
29	Monthly WV Air Emission Fee		X	X	X
30	SO2 Consumption **		X	X	X
31	CSAPR S02 Consumption **		X	X	X
32	CSAPR Annual NOx Consumption		X	X	X
33	CSAPR Seasonal NOx consumption		X	X	X
34	**Total Monthly Operation Costs**		**X**	**X**	**X**
35	Monthly FGD Maintenance Expense		X	X	X
36	Monthly Non-FGD Maintenance Expense		X	X	X
37	**Total Monthly Maintenance Expense**		**X**	**X**	**X**
38	Monthly Depreciation Expense		X	X	X
39	Monthly Catalyst Amortization Expense		X	X	X
40	Monthly CCR Depreciation Expense****		X	X	X
41	Monthly Installment of ELG Regulatory Asset Amortization****		X	X	X
42	Monthly Property Tax		X	X	X
43	**Total Monthly Other Expenses**		**X**	**X**	**X**
44	Total Monthly Operation, Maintenance, and Other Expenses		**X**	**X**	**X**
45	O&M for corresponding month of test year		X	X	X
46	Difference in Test Year Month O&M & Current Month O&M		X	X	X
47	**Gross-up for Uncollectible Expense & KPSC Maint Fee**	**1.339896**	**X**	**X**	**X**
48	**Total Revenue Requirement**		**X**	**X**	**X**

* Inventory Includes Total Kentucky Power allowances inventory.
** Includes Consumption for Mitchell only.
*** In accordance with the Commission's February 22, 2021 Order in Case No. 2020-00174 Mitchell Non-FGD rate base as of 3/31/2020 is to utilize an ROE of 9.3 percent and the return on additional Mitchell Non-FGD plant an ROE of 9.1 percent.
**** In accordance with the Commission's July 15, 2021 and May 3, 2022 Orders in Case No. 2021-00004.

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.20 - Mitchell Plant Cost of Capital

LINE NO.	Component	Balances	Cap. Structure	Cost Rates		WACC (Net of Tax)	GRCF		WACC (PRE-TAX)
		As of 3/31/2023*							
1	L/T DEBT	$962,401,699	53.10%	4.91%		2.61%	1.005523		2.62%
2	S/T DEBT	$95,743,648	5.28%	3.73%		0.20%	1.005523		0.20%
3	ACCTS REC FINANCING	$0	0.00%	0.00%		0.00%	1.005523		0.00%
4	C EQUITY	$754,394,228	41.62%	**9.90%**	**	4.12%	**1.339896**		5.52%
5	TOTAL	**$1,812,539,575**	**100.00%**			**6.93%**			**8.35%**

		Debt	Equity
6	Operating Revenues	100.0000	100.0000
7	Less Uncollectible Accounts Expense	0.4000	0.4000
8	KPSC Maintenance Assessment Fee	0.1493	0.1493
9	Income Before Income Taxes	99.4507	99.4507
10	Less State Income Taxes (Ln 4 x 5.0065)	5.0065%	4.9790
11	Taxable Income for Federal Income Taxes		94.4717
12	Less Federal Income Taxes (Ln 11*21%)		19.8391
13	Operating Income Percentage		74.6326
14	Gross Up Factor (100.00/Ln 9)	1.005523	1.339896

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.30 - Mitchell Plant Original Plant and Accumulated Depreciation

Plant	Description	Total In Service Cost	Accumulated Depreciation
Mitchell	**FGD**	X	X
Mitchell	Mitchell Units 1 and 2 Water Injection	X	X
Mitchell	Low NOX Burners	X	X
Mitchell	Low NOX Burner Modification,	X	X
Mitchell	SCR	X	X
Mitchell	Landfill	X	X
Mitchell	Coal Blending Facilities	X	X
Mitchell	SO3 Mitigation	X	X
Mitchell	Mitchell Plant Common CEMS	X	X
Mitchell	Replace Burner Barrier Valves	X	X
Mitchell	Gypsum Material Handling Facilities	X	X
Mitchell	Precipitator Modifications - Mitchell Plant Units 1 and 2	X	X
Mitchell	Bottom Ash and Fly Ash Handling - Mitchell Plant Units 1 and 2	X	X
Mitchell	Mercury Monitoring (MATS) - Mitchell Plant Units 1 and 2	X	X
Mitchell	Dry Fly Ash Handling Conversion - Mitchell Plant Units 1 and 2	X	X
Mitchell	Coal Combustion Waste Landfill - Mitchell Plant Units 1 and 2	X	X
Mitchell	Electrostatic Precipitator Upgrade - Mitchell Plant Unit 2	X	X
Mitchell	**Non-FGD Total**	X	X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.40 A - SO2 Emissions Allowance Inventory

	(1) Total Allowance Inventory (Quantity)	(2) Total Allowance Inventory (Dollar Value)	(3) Current Allowance Inventory (Quantity)	(4) Current Allowance Inventory (Dollar Value)	(5) Average Cost per Allowance (Current Allowances)
BEGINNING BALANCE	X	X	X	X	X
Additions					
Original Issuance	X	X	X	X	X
Internal Purchases	X	X	X	X	X
External Purchases	X	X	X	X	X
Power Sale/Coal Contracts	X	X	X	X	X
Consumption Adjustments for Prior Year	X	X	X	X	X
Other Acquisitions	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Withdrawals					
Internal Sales	X	X	X	X	X
External Sales	X	X	X	X	X
Power/Coal Contracts	X	X	X	X	X
Surrenders (Regular)	X	X	X	X	X
Surrenders (Consent Decree)	X	X	X	X	X
Other Issuances	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Consumption Adjustment for Mitchell	X	X	X	X	X
Consumption Adjustment for Big Sandy	X	X	X	X	X
Emissions Allowances Consumed By Kentucky Power - 1:1 (Year 2009 & Prior)	X	X	X	X	X
Emissions Allowances Consumed By Mitchell	X	X	X	X	X
Emissions Allowances Consumed By Big Sandy	X	X	X	X	X
ENDING BALANCE - Recorded on Form 2.2(	X	X	X	X	X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.40 B - CSAPR SO2 Emissions Allowance Inventory

	(1) Total Allowance Inventory (Quantity)	(2) Total Allowance Inventory (Dollar Value)	(3) Current Allowance Inventory (Quantity)	(4) Current Allowance Inventory (Dollar Value)	(5) Average Cost per Allowance (Current Allowances)
BEGINNING BALANCE	X	X	X	X	X
Additions					
Original Issuance	X	X	X	X	X
Internal Purchases	X	X	X	X	X
External Purchases	X	X	X	X	X
Power Sale/Coal Contracts	X	X	X	X	X
Consumption Adjustments for Prior Year	X	X	X	X	X
Other Acquisitions	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Withdrawals					
Internal Sales	X	X	X	X	X
External Sales	X	X	X	X	X
Power/Coal Contracts	X	X	X	X	X
Surrenders (Regular)	X	X	X	X	X
Surrenders (Consent Decree)	X	X	X	X	X
Other Issuances	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Consumption Adjustment for Mitchell	X	X	X	X	X
Consumption Adjustment for Big Sandy	X	X	X	X	X
Emissions Allowances Consumed By Kentucky Power - 1:1 (Year 2009 & Prior)	X	X	X	X	X
Emissions Allowances Consumed By Mitchell	X	X	X	X	X
Emissions Allowances Consumed By Big Sandy	X	X	X	X	X
ENDING BALANCE - Recorded on Form 2.20	X	X	X	X	X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.40 C - CSAPR Annual NOx Emissions Allowance Inventory

	(1) Total Allowance Inventory (Quantity)	(2) Total Allowance Inventory (Dollar Value)	(3) Current Allowance Inventory (Quantity)	(4) Current Allowance Inventory (Dollar Value)	(5) Average Cost per Allowance (Current Allowances)
BEGINNING BALANCE	X	X	X	X	X
Additions					
Original Issuance	X	X	X	X	X
Internal Purchases	X	X	X	X	X
External Purchases	X	X	X	X	X
Power Sale/Coal Contracts	X	X	X	X	X
Consumption Adjustments for Prior Year	X	X	X	X	X
Other Acquisitions	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Withdrawals					
Internal Sales	X	X	X	X	X
External Sales	X	X	X	X	X
Power/Coal Contracts	X	X	X	X	X
Surrenders (Regular)	X	X	X	X	X
Surrenders (Consent Decree)	X	X	X	X	X
Other Issuances	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Consumption Adjustment for Mitchell	X	X	X	X	X
Consumption Adjustment for Big Sandy	X	X	X	X	X
Emissions Allowances Consumed By Kentucky Power - 1:1 (Year 2009 & Prior)	X	X	X	X	X
Emissions Allowances Consumed By Mitchell	X	X	X	X	X
Emissions Allowances Consumed By Big Sandy	X	X	X	X	X
ENDING BALANCE - Recorded on Form 2.20	X	X	X	X	X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.40 D - CSAPR Seasonal NOx Emissions Allowance Inventory

	(1) Total Allowance Inventory (Quantity)	(2) Total Allowance Inventory (Dollar Value)	(3) Current Allowance Inventory (Quantity)	(4) Current Allowance Inventory (Dollar Value)	(5) Average Cost per Allowance (Current Allowances)
BEGINNING BALANCE	X	X	X	X	X
Additions					
Original Issuance	X	X	X	X	X
Internal Purchases	X	X	X	X	X
External Purchases	X	X	X	X	X
Power Sale/Coal Contracts	X	X	X	X	X
Consumption Adjustments for Prior Year	X	X	X	X	X
Other Acquisitions	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Withdrawals					
Internal Sales	X	X	X	X	X
External Sales	X	X	X	X	X
Power/Coal Contracts	X	X	X	X	X
Surrenders (Regular)	X	X	X	X	X
Surrenders (Consent Decree)	X	X	X	X	X
Other Issuances	X	X	X	X	X
Swaps & Loans	X	X	X	X	X
Consumption Adjustment for Mitchell	X	X	X	X	X
Consumption Adjustment for Big Sandy	X	X	X	X	X
Emissions Allowances Consumed By Kentucky Power - 1:1 (Year 2009 & Prior)	X	X	X	X	X
Emissions Allowances Consumed By Mitchell	X	X	X	X	X
Emissions Allowances Consumed By Big Sandy	X	X	X	X	X
ENDING BALANCE - Recorded on Form 2.20	X	X	X	X	X

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 3.50 - Cash Working Capital Calculation

Line	Month/Year	Mitchell Non-FGD	Mitchell FGD
1	MM YYYY	X	X
2	MM YYYY	X	X
3	MM YYYY	X	X
4	MM YYYY	X	X
5	MM YYYY	X	X
6	MM YYYY	X	X
7	MM YYYY	X	X
8	MM YYYY	X	X
9	MM YYYY	X	X
10	MM YYYY	X	X
11	MM YYYY	X	X
12	MM YYYY	X	X
13	*12 Month Expense*	X	X
14	*Line 13 Divided by 365 Equals Avg Daily Expense*	X	X
15	*Net (Lead/Lag) Days*	-6.95	-6.95
16	***Line 14 multiplied by Line 15 Equals Working Capital Requirement for Form 3.20***	**X**	**X**

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 4.00 - Monthly Revenues, Jurisdictional Allocation Factor, and (Over)/Under

Schedule of Monthly Revenues

Line No.	Description	Monthly Revenues	Percentage of Total Revenues	
1	Kentucky Retail Revenues*	X	X	*
2	FERC Wholesale Revenues	X	X	
3	Associated Utilities Revenues	X	X	
4	Non-Assoc. Utilities Revenues	X	X	
		-------------------	-------------------	
5	Total Revenues for Surcharges Purposes	X	X	
6	Non-Physical Revenues for Month	X		
7	Total Revenues for Month	X		

* Recorded on Form 1.10 for the Kentucky Retail Jurisdictional Allocation Factor.

Over/(Under) Recovery Adjustment

Line No.	Description		
1	Surcharge Amount To Be Collected	X	
2	Actual Billed Environmental Surcharge Revenues	X	
3	(Over) / Under Recovery (1) - (2) = (3)	X	*

* Recorded on Form 1.10.

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 5.00 - Allocation Factors for Residential and All Other
Based on Calendar Year XXXX

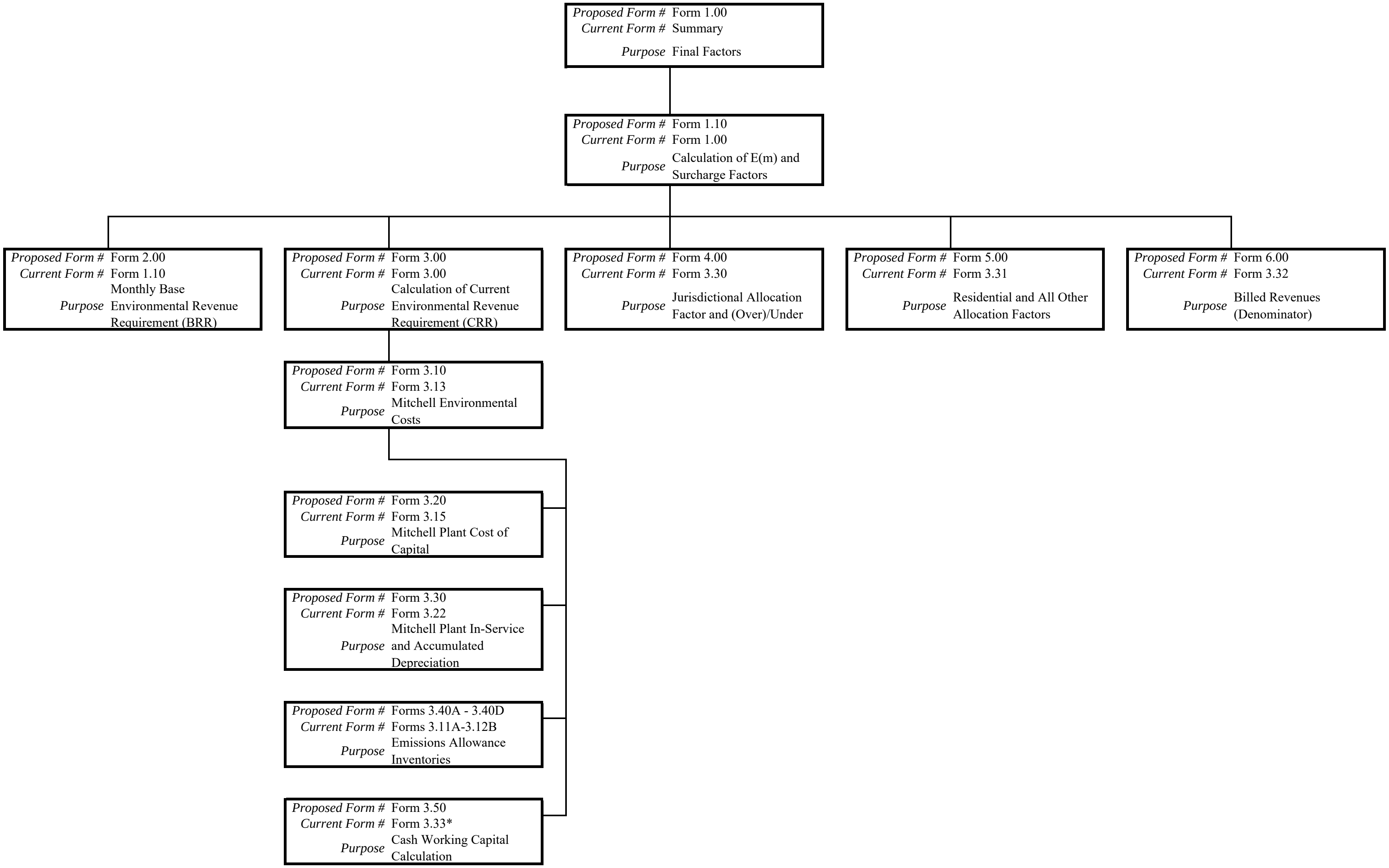
Line No.	Revenue Category	Total	Percentage of Total	Allocation
1	Residential	$X	X%	**X%**
2	All Other Classes	$X	X%	**X%**
3	Total Retail Revenues	$X	X%	**X%**
4	FERC Wholesale Revenues	$X	X%	
5	Associated Utilities Revenues	$X	X%	
6	Non Associated Utilities Revenues	$X	X%	
7	Non-Physical Sales	$X	X%	
8	Total Revenues	$X		

SAMPLE ONLY

KENTUCKY POWER COMPANY
Environmental Surcharge
Form 5.00 - Billed Revenues for Residential and All Other

Residential				
Month	Total Revenues	Decommissioning Rider Revenues	Environmental Surcharge Revenues	Non-Percentage of Revenue Rider Revenues
(1)	(2)	(3)	(4)	(5) (2)-(3)-(4)
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
Average monthly residential revenues for 12-Month Period ended with most recent expense month				X

Non-Residential, Non-Fuel Revenues						
Month	Total Revenues	Base Rate Fuel Revenue	Fuel Adjustment Clause Revenue	Decommissioning Rider Revenues	Environmental Surcharge Revenues	Non-Percentage of Revenue Rider Total Revenues
(1)	(2)	(3)	(4)	(5)	(6)	(7) (2)-(3)-(4)-(5)-(6)
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
MM YYYY	X	X	X	X	X	X
Average monthly non-residential revenues for 12-month period ended with most recent expense month						X



Note:
Forms 3.20 (Rockport Environmental Costs) and 3.21 (Rockport UPA Cost of Capital) have been removed in their entirety
Current Form 3.33 while filed monthly is not utilized within the calculation for the environmental surcharge factors per the Commission's January 13, 2021 Order in Case No. 2020-00174

Kentucky Power Company's Approved Environmental Compliance Plan

Project	Plant	Pollutant	Description	In-Service Year
1	Mitchell	NO_X, SO_2, and SO_3	Mitchell Units 1 and 2 Water Injection, Low NO_X Burners, Low NO_X Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation	1993-1994-2002-2007
2	Mitchell	SO_2 , NO_X, and Gypsum	Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities	1993-2004-2007
3-Obsolete				
4-Obsolete				
5	Mitchell	SO_2/NO_X/Particulates/VOC and etc.	Title V Air Emission Fees at the Mitchell Plant	Annual
6	Big Sandy and Mitchell	NO_X	Costs Associated with Nox Allowances	As-Needed
7	Big Sandy and Mitchell	SO_2	Costs Associated with SO_2 Allowances	As-Needed
8	Big Sandy and Mitchell	SO_2 / NO_X	Costs associated with the CSAPR Allowances	As-Needed
9	Mitchell	Particulates	Precipitator Modifications - Mitchell Plant Units 1 and 2	2007-2013
10	Mitchell	Particulates	Bottom Ash and Fly Ash Handling - Mitchell Plant Units 1 and 2	2008 & 2010
11	Mitchell	Mercury	Mercury Monitoring (MATS) - Mitchell Plant Units 1 and 2	2014
12	Mitchell	Selenium	Dry Fly Ash Handling Conversion - Mitchell Plant Units 1 and 2	2015
13	Mitchell	Fly Ash, Bottom Ash, Gypsum, and WWTP Solids	Coal Combustion Waste Landfill - Mitchell Plant Units 1 and 2	2014 & 2015
14	Mitchell	Particulates	Electrostatic Precipitator Upgrade - Mitchell Plant Unit 2	2015
15-Obsolete				
16-Obsolete				
17-Obsolete				
18-Obsolete				
19-Obsolete				
20	Mitchell	Consumables	Costs associated with the use of consumables used in conjunction with approved ECP projects. These costs include the return on inventory of consumables as well as consumption of consumables. These consumables include but are not limited to sodium bicarbonate, activated carbon, anhydrous ammonia, trona, lime hydrate, limestone, polymer, and urea.	As-Needed
21-Obsolete				
22	Mitchell	Bottom Ash and Gypsum	Costs associated with CCR compliance at the Mitchell Plant.	2023

Replacement Capacity Costs Due to the Expiration of the Rockport UPA

Year	Month	Days of the Month	MW Purchased	$/MW-Day	Cost	
2022	December 8-31	24	152.4	50	$ 182,880	
2023	January	31	152.4	50	$ 236,220	
2023	February	28	152.4	50	$ 213,360	
2023	March	31	152.4	50	$ 236,220	**$ 868,680**
2023	April	30	152.4	50	$ 228,600	**Within Test Year**
2023	May	31	152.4	50	$ 236,220	
2023	June	30	70.2	34.13	$ 71,878	
2023	July	31	70.2	34.13	$ 74,274	
2023	August	31	70.2	34.13	$ 74,274	
2023	September	30	70.2	34.13	$ 71,878	
2023	October	31	70.2	34.13	$ 74,274	
2023	November	30	70.2	34.13	$ 71,878	
2023	December	31	70.2	34.13	$ 74,274	
2024	January	31	70.2	34.13	$ 74,274	
2024	February	29	70.2	34.13	$ 69,482	
2024	March	31	70.2	34.13	$ 74,274	
2024	April	30	70.2	34.13	$ 71,878	
2024	May	31	70.2	34.13	$ 74,274	
2024	June	30	80	54	$ 129,600	
2024	July	31	80	54	$ 133,920	
2024	August	31	80	54	$ 133,920	
2024	September	30	80	54	$ 129,600	
2024	October	31	80	54	$ 133,920	
2024	November	30	80	54	$ 129,600	
2024	December	31	80	54	$ 133,920	**$ 1,288,661**
2025	January	31	80	54	$ 133,920	**Calendar year 2024**
2025	February	28	80	54	$ 120,960	
2025	March	31	80	54	$ 133,920	
2025	April	30	80	54	$ 129,600	
2025	May	31	80	54	$ 133,920	

P.S.C. KY. NO. 13
CANCELLING P.S.C. KY. NO. 12

Kentucky Power Company
1645 Winchester Avenue
Ashland, KY 41101
www.kentuckypower.com

Rates, Terms, and Conditions for Furnishing
Electric Service

*Applicable to the Entire Territory Served by Kentucky Power Company In:
Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan Counties.*

Filed with the Kentucky Public Service Commission

~~**P.S.C KY. NO. 12**~~
~~**CANCELLING P.S.C. KY. NO. 11**~~

~~KENTUCKY POWER COMPANY~~
~~1645 WINCHESTER AVENUE~~
~~ASHLAND, KY 41101~~

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

~~RATES-CHARGES-RULES-REGULATIONS FOR FURNISHING ELECTRIC SERVICE~~

~~IN THE KENTUCKY TERRITORY SERVED~~
~~BY KENTUCKY POWER COMPANY~~
~~AS STATED ON SHEET NO. 1~~

~~FILED WITH THE PUBLIC SERVICE COMMISSION OF KENTUCKY~~

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

~~Index~~

~~(Cont'd on Sheet No. 1-2)~~

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
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~~INDEX~~

~~(Cont'd on Sheet No. 1 – 3)~~

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TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

~~INDEX~~

~~THE ABOVE TARIFFS ARE APPLICABLE TO THE ENTIRE TERRITORY SERVED BY KENTUCKY POWER COMPANY IN BOYD, BREATHITT, CARTER, CLAY, ELLIOTT, FLOYD, GREENUP, JOHNSON, KNOTT, LAWRENCE, LESLIE, LETCHER, LEWIS, MAGOFFIN, MARTIN, MORGAN, OWSLEY, PERRY, PIKE AND ROWAN COUNTIES.~~

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
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In Case No.: 2023-00159 Dated XXXX XX, XXXX

Index

Terms and Conditions of Service

1. Application

Applications may be made in writing, on-line, or via telephone for customers who wish to have the Company provide electric service. Requests for service are to be made in the Customer's legal name by telephone or online at: www.kentuckypower.com. The Company has the right to reject any request for service based on 807 KAR 5:006 Section 15 and associated tariffs.

The Company may require verification of ownership of property, lease, applicant's identity, or other requested information.

A copy of the tariffs and standard terms and conditions under which service is to be rendered to the Customer will be furnished upon request and the Customer shall elect upon which tariff applicable to his service his application shall be based. A copy of the tariff is also available online at www.kentuckypower.com.

If the Company requires a written agreement from a Customer before service will be commenced, a copy of the agreement will be furnished to the Customer upon request.

When the Customer desires delivery of energy at more than one point, a separate agreement may be required for each separate point of delivery. Service delivered at each point of delivery will be billed separately under the applicable tariff.

2. Inspection

The Customer is responsible for the proper installation and maintenance of the customer's wiring and electrical equipment and the customer shall at all times be responsible for the character and condition thereof. The Company has no obligation to undertake inspection thereof and in no event shall be responsible therefore. However, the Company may disconnect or refuse to connect service if the customer's wiring is deemed unsafe by the Company.

Company may also require a new state electrical inspection should tampering, illegal use or theft of service be the basis for disconnection service.

Where a Customer's premises are located in a municipality or other governmental subdivision where inspection laws or ordinances are in effect, the Company may withhold furnishing service to new installations until the Company has received evidence that the inspection laws or ordinances have been complied with.

Where a Customer's premises are located outside of an area where inspection service is in effect, the Company may require the delivery by the Customer to the Company of an agreement duly signed by the owner and/or tenant of the premises authorizing the connection to the wiring system of the Customer and assuming responsibility therefore. No responsibility shall attach to the Company because of any waiver of this requirement.

3. Service Connections

Service connections will be provided in accordance with 807 KAR-5:041, Section 10.

The Customer should in all cases consult the Company before the Customer's premises are wired to determine the location of Company's point of service connection.

The Company will, when requested to furnish service, designate the location of its service connection. The Customer's wiring must, except for those cases listed below, be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto. When service is from an overhead system, the Customer's wiring must extend at least 18 inches beyond the building. Where Customers install service entrance facilities which have capacity and layout specified by the Company and/or install and use certain equipment specified by the Company, the Company may supply or offer to own certain facilities on the Customer's side of the point where the service wires attach to the building.

Continued on Sheet 2-2

Terms and Conditions of Service Continued

Service Connections Continued

All inside wiring must be grounded in accordance with the requirements of the National Electrical Code or the requirements of any local inspection service authorized by a state or local authority.

When a Customer desires that energy be delivered at a point or in a manner other than that designated by the Company, the Customer shall pay the additional cost of same.

4. Deposits

Prior to providing service or at any time thereafter, the Company may require a cash deposit or other guaranty acceptable to the Company to secure payment of bills except for customers qualifying for service reconnection pursuant to 807 KAR 5:006, Section 16, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Upon request from a residential customer the deposit will be returned after 18 months if the customer has established a satisfactory payment record; but commercial deposits will be retained by the Company during the entire time that the account remains active.

A. Interest

Interest will be paid on all sums held on deposit at the rate indicated in KRS 278.460. The interest will be applied by the Company as a credit to the Customer's bill or will be paid to the Customer on an annual basis. If the deposit is refunded or credited to the Customer's bill prior to the deposit anniversary date, interest will be paid or credited to the Customer's bill on a pro-rated basis.

The Company will not pay interest on deposits after discontinuance of service to the Customer. Retention of any deposit or guaranty by the Company prior to final settlement is not a payment or partial payment of any bill for service. The Company shall have a reasonable time in which to obtain a final reading and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposits.

B. Criteria for Waiver of Deposit Requirement

The Company may waive any deposit requirement based upon the following criteria, which may be considered by the Company cumulatively:

i. Satisfactory payment history with the Company, which may be established by paying all bills by due date, having no disconnections for nonpayment, having no late notices, having no defaulted credit arrangements, having no returned payments and having no energy diversion or theft of service;
ii. Satisfactory payment history with another utility acceptable to the Company;
iii. Another customer with satisfactory payment history is willing to sign as a guarantor for an amount equal to the required deposit; or
iv. Providing evidence of other collateral acceptable to Company.

C. Method of Determination – Calculated Deposits

~~1. Calculated Deposits~~

a. Deposit amounts paid by residential customers shall not exceed a calculated amount based upon actual usage data of the Customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the average bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the Customer's actual or estimated annual bill.
b. Deposit amounts paid by commercial and industrial customers shall not exceed a calculated amount based upon actual usage data of the customer at the same or similar premises for the most recent 12-month period, if such information is available. If the actual usage data is not available, the deposit amount shall be based on the typical bills of similar customers and premises in the customer class. The deposit shall not exceed 2/12 of the customer's actual or estimated annual bill.

Continued on Sheet 2-3

Terms and Conditions of Service Continued

D. Additional or Supplemental Deposit Requirement
An additional or supplemental deposit may be required if the Customer does not maintain a satisfactory credit criteria or payment history. If a change in usage or classification of service has occurred, the customer may be required to pay an additional deposit up to 2/12 of the annual usage. The Customer will receive a message on the bill informing the Customer that if the account is not current by the specified date listed an additional or supplement deposit will be charged to the account the next time the account is billed.

i. Satisfactory payment history is defined as paying all bills by due date, having no disconnections for nonpayment, having no defaulted credit arrangements, having no returned payments and having no meter diversion or theft of service.
ii. A nonresidential customer does not maintain satisfactory credit criteria when its credit score at any national independent credit rating service falls to a level that is deemed to present a risk of nonpayment, including but not limited to: below a “BB+” level at Standard and Poor’s or below “Ba1” at Moody’s. If a nonresidential customer is not rated by a national independent credit rating service, its credit may be evaluated by using credit scoring services, public record financial information, or financial scoring and modeling services, and if it is deemed that the customer presents a risk of nonpayment, a deposit may be required.

E. Recalculation of Customer Deposit
When a deposit is held longer than 18 months, the Customer may request that the deposit be recalculated based on the Customer’s actual usage. If the amount of deposit on the account differs from the recalculated amount by more than $10.00 for a residential Customer or 10 percent for a non-residential Customer, the Company may collect any underpayment and shall refund any overpayment. No refund will be made if the Customer’s bill is delinquent at the time of the recalculation.

5. Payments
Bills will be rendered by the Company to the Customer monthly or in accordance with the tariff selected applicable to the Customer’s service.

A. Equal Payment Plan (Budget)
Nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above and all residential customers have the option of paying a fixed amount each month under the Company’s Equal Payment Plan. The monthly payment amount will be based on one-twelfth of the Customer’s estimated annual usage. The payment amount is subject to periodic review and adjustment during the budget year to more accurately reflect actual usage. The normal plan period is 12 months, which may commence April through December.

In the last month of the plan (the “settle-up month”) if the actual usage during the plan period exceeds the amount billed, the Customer will be billed for the balance due. If an overpayment exists, the amount of overpayment will either be refunded to the Customer or credited to the last bill of the period. If a Customer discontinues service with the Company under the Equal Payment Plan, any amounts not yet paid shall become payable immediately.

If a Customer fails to pay bills as rendered under the Equal Payment Plan, the Company reserves the right to revoke the plan, restore the Customer to regular billing, require immediate payment of any deficiency, and require a cash deposit or other guaranty to secure payment of bills.

Customers currently enrolled in the Equal Payment Plan whose settle-up month falls within the period December through February may elect to change their settle-up month to November or March if their Equal Payment Plan account is current.

If a customer who is currently enrolled in the Equal Payment Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the Equal Payment Plan and restored to regular billing.

Continued on Sheet 2-4

Terms and Conditions of Service Continued

B. Average Monthly Payment Plan

The Average Monthly Payment Plan (AMP Plan) is available to all residential customers and nonresidential customers with accounts that are current and that maintain satisfactory credit criteria per paragraph 4(D) above.

The AMP Plan is designed to allow the Customer to pay an average amount each month based upon the actual billed amounts during the past twelve (12) months. The average payment amount is based upon the current month's total bill plus the eleven (11) preceding months. That result is divided by the total billing days associated with the billings to determine a per day average. The daily average amount is multiplied by thirty (30) to determine the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is removed, the current month's billing is added and the total is again divided by the total billing days associated with the billings to determine a per day average. Again the daily average amount is multiplied by thirty (30) to find the new average payment amount. The average monthly payment amount is calculated each and every month in this manner.

If a customer who is currently enrolled in the AMP Plan elects to take service under Tariff N.M.S. II, such customer will be removed from the AMP Plan and restored to regular billing.

The difference between the actual billings and the AMP Plan billings will be carried in a deferred balance. Both the debit and credit differences will accumulate in the deferred balance for the duration of the AMP Plan year, which is twelve (12) consecutive billing months. At the end of the AMP Plan year (anniversary month), the current month's billing plus the eleven (11) preceding month's billing is summed and divided by the total billing days associated with the billings to determine a per day average. That result is multiplied by thirty (30) to calculate the AMP Plan's monthly payment amount. In addition, the net accumulated deferred balance is divided by 12. This result is added or subtracted to the calculated average payment amount starting with the next billing of the new AMP plan year and will be used in the average payment amount calculation for the remaining AMP plan year. Settlement occurs only when participation in the AMP Plan is terminated. This happens if any account is final billed, if the customer requests termination, or at the Company's discretion when the customer fails to make two or more consecutive monthly payments on an account by the due date. The deferred balance (debit or credit) is then applied to the billing now due.

In such instances where sufficient billing history is not available, an AMP Plan may be established by using the actual billing history available throughout the first AMP Plan year.

C. All Payments

All bills are due and payable within twenty-one (21) days after their mailing date. ~~the time limits specified in the tariff.~~ Failure to receive a bill will not entitle a Customer to any discount or to the remission of any charges for non-payment within the time specified. The word "month" as used herein and in the tariffs is hereby defined to be the elapsed time between 2 successive meter readings approximately 30 days apart.

In the event of the stoppage of or the failure of any meter to register the full amount of energy consumed, the Customer will be billed for the period based on an estimated consumption of energy in a similar period of like use.

Delayed Payment Charge

The tariffs of the Company are met if the account of the Customer is paid within the time limit specified in the tariff applicable to the Customer's service. On all non-residential accounts not so paid, an additional charge of 5% of the unpaid balance will be applied. ~~To discourage delinquency and encourage prompt payment within the specified time limit, certain tariffs contain a delayed payment charge, which may be added in accordance with the tariff under which service is provided.~~ Any one delayed payment charge billed against the Customer for non-payment of bill or any one forfeited discount applied against the Customer for non-payment of bill may be remitted, provided the Customer's previous accounts are paid in full and provided no delayed payment charge or forfeited discount has been remitted under this clause during the preceding six months.

Continued on Sheet 2-5

Terms and Conditions of Service Continued

6. Payment Arrangements

In accordance with 807 KAR 5:006 Section 14(2), Kentucky Power shall negotiate and accept reasonable payment arrangements at the request of a residential customer who has received a termination notice for failure to pay. Payment arrangements will include the following reasonable provisions:

a. Partial Payment Plans are available up to the day prior to the termination date printed on a customer's termination notice.
b. Partial Payment Plans are available only for current balances and balances up to 30 days in arrears.
c. Any balance more than 30 days in arrears must be paid in full at least one business day prior to the date the Partial Payment Plan is established.
d. Customers with delinquent or otherwise unsatisfied Partial Payment Plans may not be eligible for a Partial Payment Plan.
e. Unpaid deposit amounts are not eligible for inclusion in a Partial Payment Plan.
f. Company reserves the right to refuse unverifiable third-party pledges toward a customer's obligations under a Partial Payment Plan.
g. Customer shall be advised, in writing or by telephone, the date and the amount of payment(s) due. Service may be terminated without additional notice if the Customer fails to meet the obligations of the agreed plan.
h. It is the responsibility of the customer presenting the Medical Certificate to contact the Company to negotiate a payment arrangement based upon the customer's ability to pay. The payment arrangement shall require that the account become current no later than October 15.
i. Customers presenting Certification from the Cabinet for Health and Family Services must do so during the initial 10 day termination notice period. As a condition of the 30-day extension, the customer shall exhibit good faith by entering into a payment arrangement.

7. Underground Service

When a real estate developer desires an underground distribution system within the property which he is developing or when a Customer desires an underground service, the real estate developer or the Customer as the case may be, shall pay the Company the difference between the anticipated cost of the underground facilities so requested and the cost of the overhead facilities which would ordinarily be installed in accordance with 807 KAR 5:041, Section 21, and the Company's underground service plan as filed with the Public Service Commission. Upon receipt of payment, the Company will install the underground facilities and will own, operate and maintain the same.

Please see Tariff Sheet No. 14~~40~~-1 for the underground differential cost schedule.

8. Company's Liability

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but does not guarantee uninterrupted service. The Company shall not be liable for damages in case such supply should be interrupted or fail by reason of an event of Force Majeure. Force Majeure consists of an event or circumstance which prevents Company from providing service, which event or circumstance was not anticipated, which is not in the reasonable control of, or the result of negligence of, the Company, and which, by the exercise of due diligence, Company is unable to overcome or avoid or cause to be avoided. Force Majeure events includes acts of God, the public enemy, accidents, labor disputes, orders or acts of civil or military authority, breakdowns or injury to the machinery, transmission lines, distribution lines or other facilities of the Company, or extraordinary repairs.

Unless otherwise provided in a contract between the Company and Customer, the point at which service is delivered by Company to Customer, to be known as "delivery point," shall be the point at which the Customer's facilities are connected to the Company's facilities. The metering device is the property of the Company. The meter base, connection, grounds and all associated internal parts inside the meter base are customer owned and are the responsibility of the customer to install and maintain. The Company shall not be liable for any loss, injury, or damage resulting from the Customer's use of their equipment or occasioned by the energy furnished by the Company beyond the delivery point.

Continued on Sheet 2-6

Terms and Conditions of Service Continued

Company's Liability Continued

Any new installation, upgrade or other modification of an existing meter installation shall be made using only Company-supplied or Company-approved meter bases. A list of Company-approved meter bases and specifications can be found on the Company's website at: www.kentuckypower.com.

The Customer shall provide and maintain suitable protective devices on their equipment to prevent any loss, injury or damage that might result from single phasing conditions or any other fluctuation or irregularity in the supply of energy. The Company shall not be liable for any loss, injury or damage resulting from a single phasing condition or any other fluctuation or irregularity in the supply of energy which could have been prevented by the use of such protective devices. The Company shall not be liable for any damages, whether direct, incidental or consequential, including, without limitation, loss of profits, loss of revenue, or loss of production capacity occasioned by interruptions, fluctuations, or irregularity in the supply of energy.

The Company is not responsible for loss or damage caused by the disconnection or reconnection of its facilities. The Company is not responsible for loss or damages caused by the theft or destruction of Company facilities by a third party.

The Company will provide and maintain the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus, which may be required for the proper measurement of and protection to its service. All such apparatus shall be and remain the property of the Company.

9. Customer's Liability

In the event of loss or injury to the property of the Company through misuse by, or the negligence of, the Customer or the employees of the same, the cost of the necessary repairs or replacement thereof shall be paid to the Company by the Customer.

Customers will be responsible for tampering with, interfering with, or breaking the seals of meters, or other equipment of the Company installed on the Customer's premises. The Customer hereby agrees that no one except the employees of the Company shall be allowed to make internal or external adjustments to any meter or any other piece of apparatus, which shall be the property of the Company.

The Company shall have the right at all reasonable hours to enter the premises of the Customer for the purpose of installing, reading, removing, testing, replacing or otherwise disposing of its apparatus and property, and the right of entire removal of the Company's property in the event of the termination of the contract for any cause. The Company may assess charges based on electric usage and damages to all Company equipment.

10. Extension of Service

The electric facilities of the Company shall be extended or expanded to supply electric service to all residential Customers and small commercial Customers which require single phase line where the installed transformer capacity does not exceed 25 KVA in accordance with 807 KAR 5:041, Section 11.

The electric facilities of the Company shall be extended or expanded to supply electric service to Customers other than those named in the above paragraph when the estimated revenue is sufficient to justify the estimated cost of making such extensions or expansions as set forth below.

Continued on Sheet 2-7

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

Extension of Service Continued

For services to be delivered to Commercial, Industrial, Mining and multiple housing project Customers up to and including estimated demands of 500 KW requiring new facilities, the Company will: (a) where the estimated revenue for one year exceeds the estimated installed cost of new local facilities required, provide such new facilities at no cost to the Customer; (b) where the estimated revenue for one year is less than the installed cost of new local facilities required, the Customer will be required to pay a contribution in aid of construction equal to the difference between the installed cost of the new facilities required to service the load and the estimated revenue for one year; (c) if the Company has reason to question the financial stability of the Customer and/or the life of the operation is uncertain
or temporary in nature, such as construction projects, oil and gas well drilling, sawmills and mining operations, the Customer shall pay a contribution in aid of construction, consisting of the estimated labor cost to install and remove the facilities required plus the cost of unsalvageable material, before the facilities are installed.

For service to be delivered to Customers with demand levels higher than those specified above, the annual cost to serve the Customer’s requirements shall be compared with the estimated revenue for one year to determine if a contribution in aid of construction, and/or a special minimum and/or other arrangement may be necessary. The annual cost to serve shall be the sum of the following components:

i. The annual fixed costs of the generation, transmission and distribution facilities related to the Customer’s requirements. These fixed costs will be calculated at 21.95% of the value to be based on the year-end embedded investment depreciated in all similar facilities of the Company.
ii. The annual energy cost based on the latest available production costs related to the Customer’s estimated annual energy use requirements.
iii. The annual fixed costs of the new local facilities necessary to provide the service requested calculated at 21.95% of the installed cost of such facilities.

If the estimated revenue for one year is greater than the cost to serve as describe herein, the Company may provide any new local facilities required at no cost to the Customer. If the estimated revenue for one year is less than the cost to serve as described herein, the Company will require the Customer to pay a contribution in aid of construction equal to the difference between the annual cost to serve as calculated and the estimated revenue for one year divided by 21.95%, but in no case to exceed the installed cost of the new facilities required. If, however, the annual cost to serve excluding the cost of new facilities paid for by the Customer exceeds the estimated revenue for one year, the Company, will, in addition to a contribution in aid of construction, require a special minimum or other arrangement to compensate the Company for such deficiency in venue.

Except where service is rendered in accordance with 807 KAR 5:041, Section 11, as described herein, the Company may require the Customer to execute an Advance and Refund Agreement where the Company reasonably questions the longevity of the service or the estimated energy use and demand requirements provided by the Customer. Under the Advance and Refund Agreement, the Customer shall pay the company the estimated total installed cost of the required new facilities which advance could be refunded over a five year period under certain circumstances. Over the five year period the Customer’ electric bill would be credited each month up to the amount of 1/60th of the total amount advanced.

11. Extension of Service to Mobile Home
The electrical facilities of the Company will be extended or expanded to supply electric service to mobile homes in accordance with 807 KAR 5:041, Section 12.

12. Location and Maintenance of Company Equipment
The Company shall have the right to construct its poles, lines and circuits on the property, and to place its transformers and other apparatus on the property or within the building of the Customer, at a point or points convenient for such purposes, as required to serve such Customer, and the Customer shall provide suitable space for the installation of necessary measuring instruments so that the latter may be protected from injury by the elements or through the negligence or deliberate acts of the Customer or of any employee of the same.

Continued on Sheet 2-8

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

13. Billing Form

Pursuant to 807 KAR 5:006, Section 7, copies of the billing forms used by the Company are shown on Sheet Nos. 2-14~~7~~ thru 2-23~~4~~.

14. Rate Schedule Selection

The Company will explain to the Customer, at the beginning of service or upon request, the Company's rates available to the Customer. Company will assist Customer in the selection of the rate schedule best adapted to Customer's service requirements, provided, however, that Company does not assume responsibility for the selection or that Customer will at all times be served under the most favorable rate schedule.

Customer may change their initial rate schedule selection to another applicable rate schedule at any time by either written notice to Company and/or by executing a new contract for the rate schedule selected, provided that the application of such subsequent selection shall continue for 12 months before any other selection may be made. In no case will the Company refund any monetary difference between the rate schedule under which service was billed in prior periods and the newly selected rate schedules.

15. Monitoring Usage

At least once quarterly the Company will monitor the usage of each customer according to the following procedure:

a. The Customer's monthly usage will be compared with the usage of the corresponding period of the previous year.
b. If the monthly usage for the two periods is substantially the same or if any difference is known to be attributed to unique circumstances, such as unusual weather conditions, common to all customers, no further review will be made.
c. If the monthly usage is not substantially the same and cannot be attributed to a readily identified common cause, the Company will compare the Customer's monthly usage records for the 12-month period with the monthly usage for the same months of the preceding year.
d. If the cause for the usage deviation cannot be determined from analysis of the Customer's meter reading and billing records, the company will contact the Customer to determine whether there have been changes that explain the increased or decreased usage.
e. Where the deviation is not otherwise explained, the Company will test the Customer's meter to determine whether it shows an average error greater than 2 percent fast or slow.
f. The Company will notify the Customer of the investigation, its findings, and any refunds or back billing in accordance with 807 KAR 5:006, Section 11(4) and (5).

In addition to the quarterly monitoring, the Company will immediately investigate usage deviations brought to its attention as a result of its on-going meter reading, billing processes, or customer inquiry.

16. Use of Energy by Customer

The tariffs for electric energy given herein are classified by the character of use of such energy and are not available for service except as provided herein.

Upon the expiration of an electric service contract, if required by the terms of the tariff, the Customer may elect to renew the contract upon the same or another tariff published by the Company available to the Customer and applicable to the Customer's requirements, except that in no case shall the Company be required to maintain transmission, switching or transformation equipment different from or in addition to that generally furnished to other Customers receiving electrical supply under the terms of the tariff elected by the Customer.

The service connections, transformers, meters and appliances supplied by the Company for each Customer have a definite capacity and no additions to the equipment, or load connected thereto, will be allowed except by consent of the Company.

Continued on Sheet 2-9

Terms and Conditions of Service Continued

Use of Energy by Customer Continued

The Customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to same, and the electric energy must not be used in such a manner as to cause unprovided-for voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances, and also as to whether the operation of such apparatus or appliances is or will be detrimental to its general service.

No attachment of any kind whatsoever may be made to the Company's lines, poles, cross arms, structures or other facilities without the express written consent of the Company.

All apparatus used by the Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and the proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be of a type to give maximum starting torque with minimum current flow, and must be of a type, and equipped with controlling devices, approved by the Company. The Customer agrees to notify the Company of any increase or decrease in his connected load

The Company will not supply service to Customers who have other sources of electrical energy supply except under tariffs that specifically provide for same.

The Customer shall not be permitted to operate generating equipment in parallel with the Company's service except with express written consent of the Company.

Resale of energy will be permitted only with express written consent by the Company.

17. Residential Service

Except as otherwise provided in these tariffs, individual residences shall be served individually with single-phase secondary service under the applicable residential service tariff. Customer may not take service for 2 or more separate residences through a single point of delivery under any tariff. Exclusions may be allowed pursuant to 807 KAR 5:046 (Prohibition of master metering).

The residential service tariff shall cease to apply to that portion of a residence which becomes regularly used for business, professional, institutional or gainful purposes, which requires three phase service or primary service or which requires service to motors in excess of 10 HP each. Under these circumstances, Customer shall have the choice of: (1) separating the wiring so that the residential portion of the premises is served through a separate meter under the residential service tariff, and the other uses as enumerated above are served through a separate meter or meters under the applicable general service tariff; or (2) taking the entire service under the applicable general service tariff.

Detached building or buildings, actually appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the Customer's residence wiring through the residence meter and under the applicable residential service tariff.

18. Denial or Discontinuance of Service

The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company for any service theretofore rendered at any location. Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent or person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made.

Continued on Sheet 2-10

Terms and Conditions of Service Continued

Denial or Discontinuance of Service Continued

Unpaid balances of previously rendered Final Bills may be transferred to any account for which Customer has responsibility and may be included on initial or subsequent bills for the account to which the transfer was made. Such transferred Final Bills, if unpaid, will be a part of the past due balance of the account to which they are transferred. When there is no lapse in service, such transferred Final Bills will be subject to Company's collections and disconnect procedures in accordance with 807 KAR 5:006, Section 15(1)(f). Final Bills transferred following a lapse in service will not be subject to disconnection unless: (1) such service was provided pursuant to a fraudulent application submitted by Customer; (2) Customer and Company have entered into a contractual agreement which allows for such a disconnection; or (3) the current account is subsequently disconnected for service supplied at that point of delivery, at which time, all unpaid and past due balances must be paid prior to reconnect.

19. Special Charges

a. Reconnection and Disconnect Charges
In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3)(b), payable in advance, in accordance with the following schedule. However, those Customers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

Reconnect for nonpayment during regular hours	$4.70
Reconnect at the end of the day (no "Call Out" required)	$30.00
Reconnect for nonpayment when a "Call Out" is required prior to 8:00PM (A "Call Out" is when an employee must be called in to work on overtime basis to make the reconnect trip. Reconnection for nonpayment will not be made when a "Call Out" after 8:00 p.m. is required)	$95.00
Reconnect for nonpayment when double time is required (Sunday and Holiday)	$124.00
Termination or field trip	$4.70

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

b. Meter Read Check
Pursuant to 807 KAR 5:006, Section 9(3)(d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of $21.00 to cover the handling cost.

c. Returned Check Charge
In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of $14.65 to cover the handling costs.

d. Meter Test Charge
Where test of a meter is made upon written request by the Customer pursuant to 807 KAR 5:006, Section 19, the Customer will be charged $48.00 if such test shows that the meter was not more than two percent (2%) fast.

Continued on Sheet 2-11

Terms and Conditions of Service Continued

Special Charges Continued

e. Work Performed on Company's Facilities at Customer's Request
Whenever, at the request and for the benefit of the Customer, work is performed on the Company's facilities, including the relocation, or replacement of the Company's facilities, the Customer shall pay to the Company in advance of the Company undertaking the work the estimated total cost of such work. This cost shall be itemized by major categories and shall include the Company's overheads and shall be credited with the net value of any salvageable material. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the Customer.

Reasonable notice of not less than three working days shall be given to the Company for all requested work except for the covering of the Company's lines. Notice of any request for the Company to cover its lines shall be given at least two days in advance. The Company will endeavor to comply with all timely requests, but work may be delayed because of demands on the Company's personnel and equipment.

If the cost, as calculated above, is $500 or less for covering the Company's distribution facilities no charge will be imposed. All costs in excess of $500 for covering the Company's distribution facilities shall be paid by the Customer, in advance of the Company undertaking the work. The actual cost for the work performed shall be calculated at the completion of the work and the appropriate charge or refund will be made to the customer.

20. Refunds to Residential Customers
The Company may make a refund to residential customers by one of the following means: a credit to the Customer's bill, a prepaid card, or a check or electronic funds transfer (EFT).

The Company acting through its customer service representative shall fully address and resolve any customer complaints or disputes related to: (a) the accuracy of the names and last known addresses of the customer to receive prepaid cards; (b) the effective delivery and receipt of the prepaid cards; and (c) the amount of any refunds.

21. Alerts and Subscriptions
Kentucky Power offers an optional Mobile Alert Service for customers through which participating customers can elect to receive notifications from the Company via e-mail or text message. The Company provides billing and payment alerts and alerts relating to outages. These alerts are supplemental to standard communications from the Company and to the extent any discrepancies exist between the information contained in the mobile alerts and the information contained in standard communications from the Company, the information in the standard communications from the Company shall prevail.

Customers interested in receiving mobile alerts from Kentucky Power may sign up for the service through the Company's website at www.kentuckypower.com. The full terms and conditions of participating in the Kentucky Power Mobile Alert Service are included on the Company's website. Customers wishing to participate in Kentucky Power's Mobile Alert Service and to receive alerts via e-mail should add communications@kentuckypower-mail.com to the customer's email address book or spam filter to avoid alert communications from Kentucky Power being directed to spam. Customers are advised to contact their e-mail service provider for instructions on how to add addresses to an address book or spam filter if needed.

E-mail addresses from which alerts are sent through the Mobile Alert Service are used for sending e-mails only. Any e-mails sent to those addresses will not be received by the Company and the Company will not respond. Any electronic communication to the Company should be sent to Communications@kentuckypower-mail.com.

There is no charge from the Company for the Mobile Alert Service; however, message and data rates may apply. Customers are advised to verify message and data rates with their cellular and internet service providers.

Information regarding the types of alerts and the Mobile Alert Service in general are provided below.

Continued on Sheet 2-12

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued

Billing and Payment Alerts
Billing and payment alerts provided through Kentucky Power's Mobile Alert Service are in addition to regular billing statements, payment notifications, disconnect notices, or other standard communications sent by Kentucky Power or its third party partners as required by law, regulation, or tariff filed by Kentucky Power or its subsidiaries. These alerts are not a replacement for any regular billing statement, payment notifications, disconnect notices, or other standard communications. In the event of a discrepancy between the information provided in a billing or payment alert provided through the Mobile Alert Service and the information provided in the Company's standard communication, the information in the standard communication shall prevail.

Kentucky Power shall not have any liability for any delay or failure to deliver a billing or payment alert or for any mistakes or errors in any billing or payment alert provided through the Mobile Alerts Service.

Outage Alerts
Kentucky Power provides alerts relating to system outages through its Mobile Alert Service. Outage alerts will be sent when the Company has evidence of an outage at a subscribed address. Due to variations in equipment from one area to another, it is possible that the accuracy of outage alerts will vary from one area to another. Recipients shall consider any outage related information as guidance and not as an absolute guarantee. Kentucky Power will send outage related notifications based upon available information and does not guarantee that the notifications will be without error.

Planned outages and short-duration outages will normally not generate an outage-related notification. During large-scale outage events, the frequency and timeliness of outage updates may be impacted.

Kentucky Power shall not have any liability for any delay or failure to deliver an outage-related notification.

General
Kentucky Power does not warrant or guarantee that alerts will be sent or received, and Kentucky Power shall not be responsible for any lost or misdirected messages.

Customers electing to participate in Kentucky Power's Mobile Alert Service authorize the Company to contact them via their elected communication method with transactional messages pertaining to the service. Participation in the Mobile Alert Service shall be considered as affirmative consent to receive the related messages should these messages ever be classified as commercial in nature.

Kentucky Power shall not have any liability under any theory of recovery, whether in contract or tort, for any loss or damages due to delay or failure to deliver an alert through the Mobile Alert Service. Without limiting the previous sentence, Kentucky Power disclaims any liability, expressed or implied, for indirect or consequential damages arising from a customer's subscription to Kentucky Power's Mobile Alert Service.

Customer agrees not to publish, copy, communicate to the public, edit, retransmit, or amend any data received as part of Kentucky Power's Mobile Alert Service. The data communicated via the Mobile Alert Service is provided for the participating customer's personal non-commercial use only and may not be used for any other purpose.

Personal information and data ("Personal Data") provided by customers when using Kentucky Power's Mobile Alert Service will only be used by Kentucky Power and its suppliers and contractors for Mobile Alert Service-related purposes. Data other than Personal Data may be aggregated and used by the Company for the purpose of undertaking market research or in facilitating reviews, developments and improvements to Kentucky Power's Mobile Alert Service.

Continued on Sheet 2-13

Terms and Conditions of Service Continued

Alerts and Subscriptions Continued

Customers participating in the Mobile Alert Service may discontinue a portion of or all alerts at any time by modifying their alert subscription or by unsubscribing entirely. Customers wishing to modify or unsubscribe from the Mobile Alert Service may do so at the Company's website: www.kentuckypower.com or by contacting Kentucky Power's Customer Operations Centers at 1-800-572-1113. Kentucky Power will process a request to unsubscribe from the Mobile Alert Service within ten days of receiving the request. Kentucky Power is authorized to send a communication to a customer requesting to unsubscribe from the Mobile Alert Service to confirm the request.

The terms and conditions the Company's Mobile Alert Service shall be governed by applicable state law.

Customers electing to participate in the Company's Mobile Alert Service agree to the terms and conditions of the service and further agree that the terms and conditions may be updated from time to time. The Company will provide customers participating in the Mobile Alert Service with updated terms and conditions as they become effective. Customers participating in the Mobile Alert Service must take affirmative action to withdraw from the service if the customer does not agree with any new or updated term or condition of service. Failure to withdraw after an updated term and condition is provided by the Company means that the customer accepts the new or updated terms and conditions.

<u>Additional Terms and Conditions for E-mail Alerts</u>
If a customer sends an email to Kentucky Power with questions or comments, Kentucky Power may use the customer's e-mail address and other personal information included in the correspondence in order to respond. If a customer provides the Company with an e-mail address in order to receive alerts, Kentucky Power may use that e-mail address to send the customer other types of information.

A customer may unsubscribe from receiving e-mail alerts by clicking the "Unsubscribe" link near the bottom of an e-mail alert.

<u>Additional Terms and Conditions for Text Message Alerts</u>
Customers may elect to receive text alerts through Kentucky Power's Mobile Alert Service. For text alerts, message and data rates may apply consistent with the customer's mobile phone service agreement. Kentucky Power assumes no responsibility for any service charges received from customer's mobile phone service providers for text alerts received through the Mobile Alert Service. Kentucky Power is not responsible for and will not be liable for any breach of the terms of an agreement between a customer electing to receive text alerts through the Mobile Alert System and that customer's mobile phone service provider or for any mistake that may arise in the billing process.

To receive text alerts from the Company through the Mobile Alert Service, the customer must be the owner or legitimate user of the mobile phone registered or have the express consent of the owner or legitimate user. Customers electing to receive text alerts from the Company through the Mobile Alert Service are responsible for providing and maintaining a mobile phone and ensuring connection to a mobile network capable of receiving the text alerts.

Customers electing to receive text alerts through the Mobile Alert Service acknowledge that the text alerts may, at any time, be adversely affected by problems with the mobile phone network including, without limitation, interference to the network coverage. Kentucky Power shall not be responsible or liable for any loss, damage, or expense incurred directly or indirectly by customers electing to receive text alerts through the Mobile Alert Service as a result of any difficulties experienced by any cellular phone service provider.

In the event a customer electing to receive text alerts through the Mobile Alert Service changes mobile phone service providers or telephone number, that customer is required to subscribe again to receive text alerts. If no alerts are sent or received for eighteen months, a customer's opt-in to that offering will expire. A customer must opt-in again to the program in order to receive alerts.

Kentucky Power may discontinue text alerts at any time. Customers electing to receive text alerts through the Mobile Alert Service will receive text alerts from 23711. Customers may unsubscribe from text alerts by texting STOP to 23711 and may obtain assistance via text by texting HELP to 23711.

Continued on Sheet 2-14

Terms and Conditions of Service Continued

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before Month DD, YYYY **$XXX.XX**
Bill mailing date is Month DD, YYYY
Account #XXX-XXX-XXX-X-X

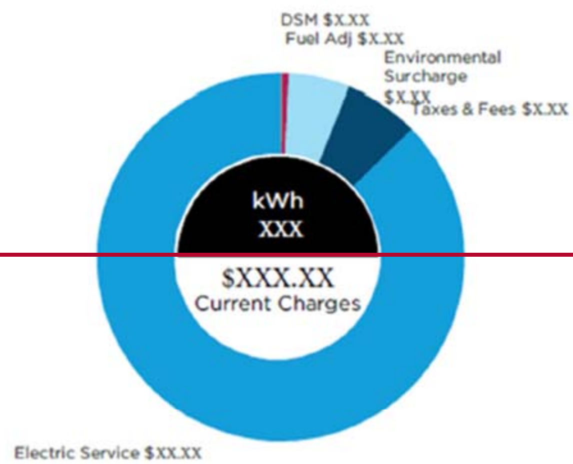
SERVICE ADDRESS: KENTUCKY RESIDENTIAL ACCOUNT,
2-1 19
030000002 01 SP 0.53
KENTUCKY RESIDENTIAL ACCOUNT

CY 15

Notes from KPCO:

Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at AEPPaperless.com!

Current bill summary:
Billing from MM/DD/YY - MM/DD/YY (XX days)



Usage History (kWh):

Methods of Payment

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Need to get in touch?
Customer Operations Center: 1-800-572-1113
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.   Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY RESIDENTIAL ACCOUNT

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

10196
Account #XXX-XXX-XXX-X-X
KENTUCKY RESIDENTIAL ACCOUNT
Amount due on or before Month DD, YYYY **$XXX.XX**

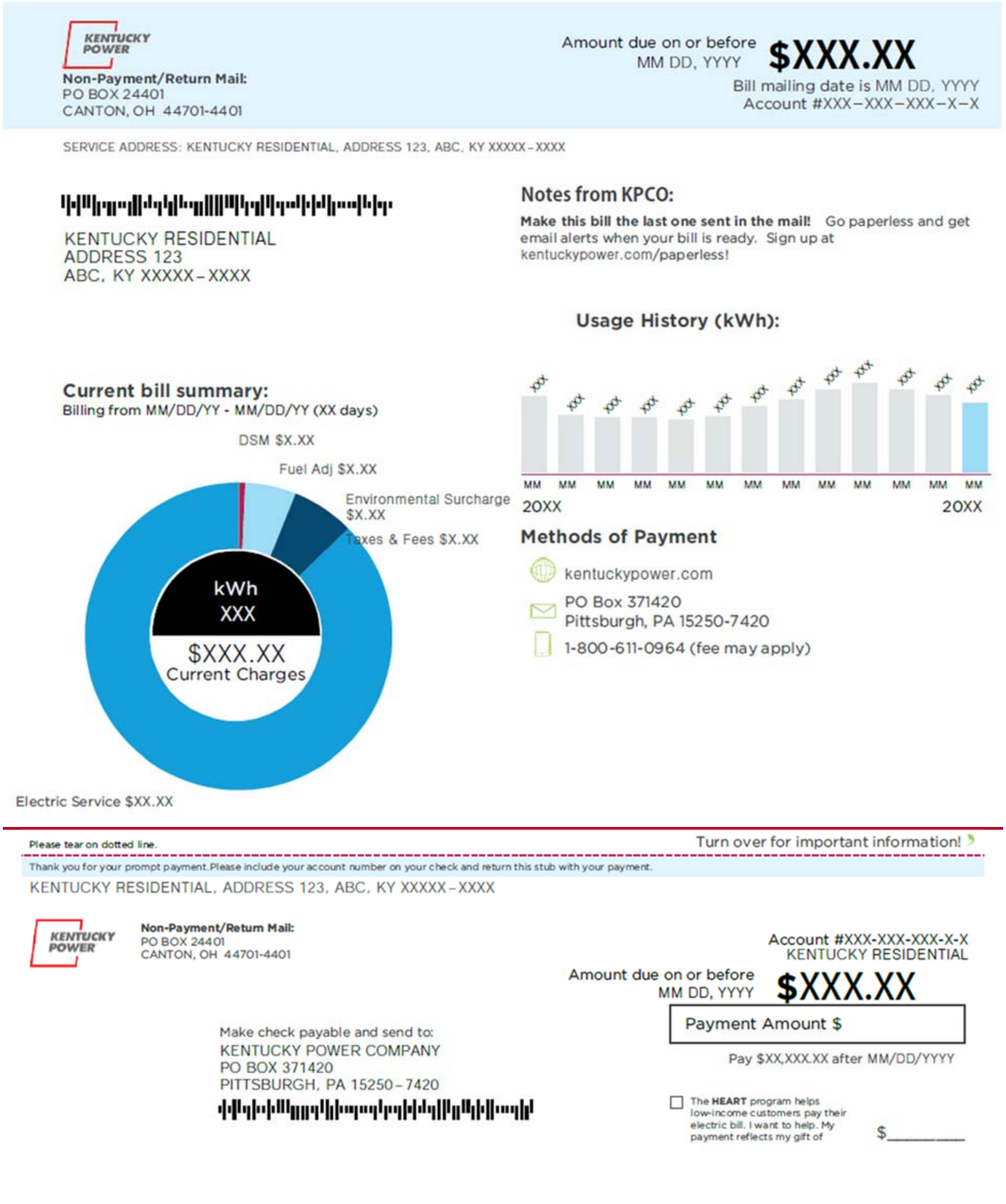
Payment Amount $

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420
PITTSBURGH, PA 15250-7420

The HEART program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

000010196000010196010000000000003000004444180208030159000003

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX



KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX–XXX–XXX–X–X

SERVICE ADDRESS: KENTUCKY RESIDENTIAL, ADDRESS 123, ABC, KY XXXXX–XXXX

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX–XXXX

Notes from KPCO:
Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

Usage History (kWh):

Current bill summary:
Billing from MM/DD/YY - MM/DD/YY (XX days)

Methods of Payment
kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Please tear on dotted line.
Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY RESIDENTIAL, ADDRESS 123, ABC, KY XXXXX–XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY RESIDENTIAL

Amount due on or before MM DD, YYYY **$XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420
PITTSBURGH, PA 15250–7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

Continued on Sheet 2-15

KENTUCKY POWER

Service Address:

XXXX-XX

KPCO RESIDENTIAL CUSTOMER
123 ANYWHERE CT
ANYWHERE, KY 12345-1234

Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount due at last billing	$	XXX.XX
Payment MM/DD/YY - Thank you		-XXX.XX
Previous Balance Due	$	X.XX
Current KPCO Charges		
Tariff 015 - Residential Service MM/DD/YY		
Rate Billing	$	XXX.XX
Federal Tax Cut Credit @ x.xxxxxxx		-X.XX
Fuel Adj @ X.XXXXXX Per kWh		XX.XX
DSM Adj @ X.XXXXXX Per kWh		XX.XX
Residential Energy Assistance @ $X.XX		XX.XX
Capacity Charge @ X.XXXXXX Per kWh		XX.XX
Environmental Adj X.XXXXXX%		X.XX
Decommissioning Rider X.XXXXXX%		X.XX
Purchase Power Adj @X.XXXXXXX Per kWh		XX.XX
Renewable Power Option Rider		XX.XX
School Tax		XX.XX
Franchise Tax		XX.XX
State Sales Tax		XX.XX
Current Balance Due	$	XXX.XX
Homeserve Warranty Service (855-769-6267)	$	XX.XX
Total Balance Due	$	XXX.XX

Usage Details:

Values reflect changes between current month and previous month.

Total usage for the past 12 months: X,XXX kWh
Your average monthly usage: X,XXX kWh

Meter Read Details:

Meter Details:

Meter #XXXXXXXXX					
Prev.	Type	Current	Type	Metered	Usage
XX,XXX	Actual	XX,XXX	Actual	X,XXX	X,XXX kWh
Service Period MM/DD - MM/DD				Multiplier X.XXXXXX	
Next scheduled read date should be between Month DD and Month DD.					

Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO

www.kyelectricalprotectionplan.com

KENTUCKY POWER

Service Address:

KENTUCKY RESIDENTIAL
ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment 02/07/22 - Thank You		-XXX.XX
Previous Balance Due	**$**	**X.XX**
Current KPCO Charges		
Tariff XXX - Residential Service XX/XX/XX		
Rate Billing	$	XXX.XX
Federal Tax Change @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Residential Energy Assistance @ $X.XX		XX.XX
Distribution Reliability Rider @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitization Financing Rider X.XXXXX%		XX.XX
Decommissioning Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	**XXX.XX**
Homeserve Warranty Service	$	XX.XX

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXXXX	Actual	XXXXX	Actual	XXX	XXX kWh
Service Period XX/XX – XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD.					

Notes from KPCO:

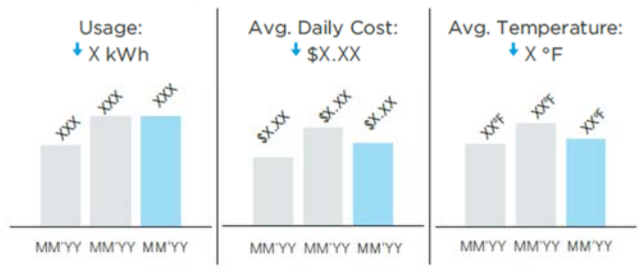
Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Homeserve USA is optional. Homeserve USA is not the same as KPCO and is not regulated by the KY Public Service Commission. A customer does not have to buy the Warranty Service in order to continue to receive quality regulated services from KPCO.

www.kyelectricalprotectionplan.com

Usage Details:

↑↓Values reflect changes between current month and previous month.



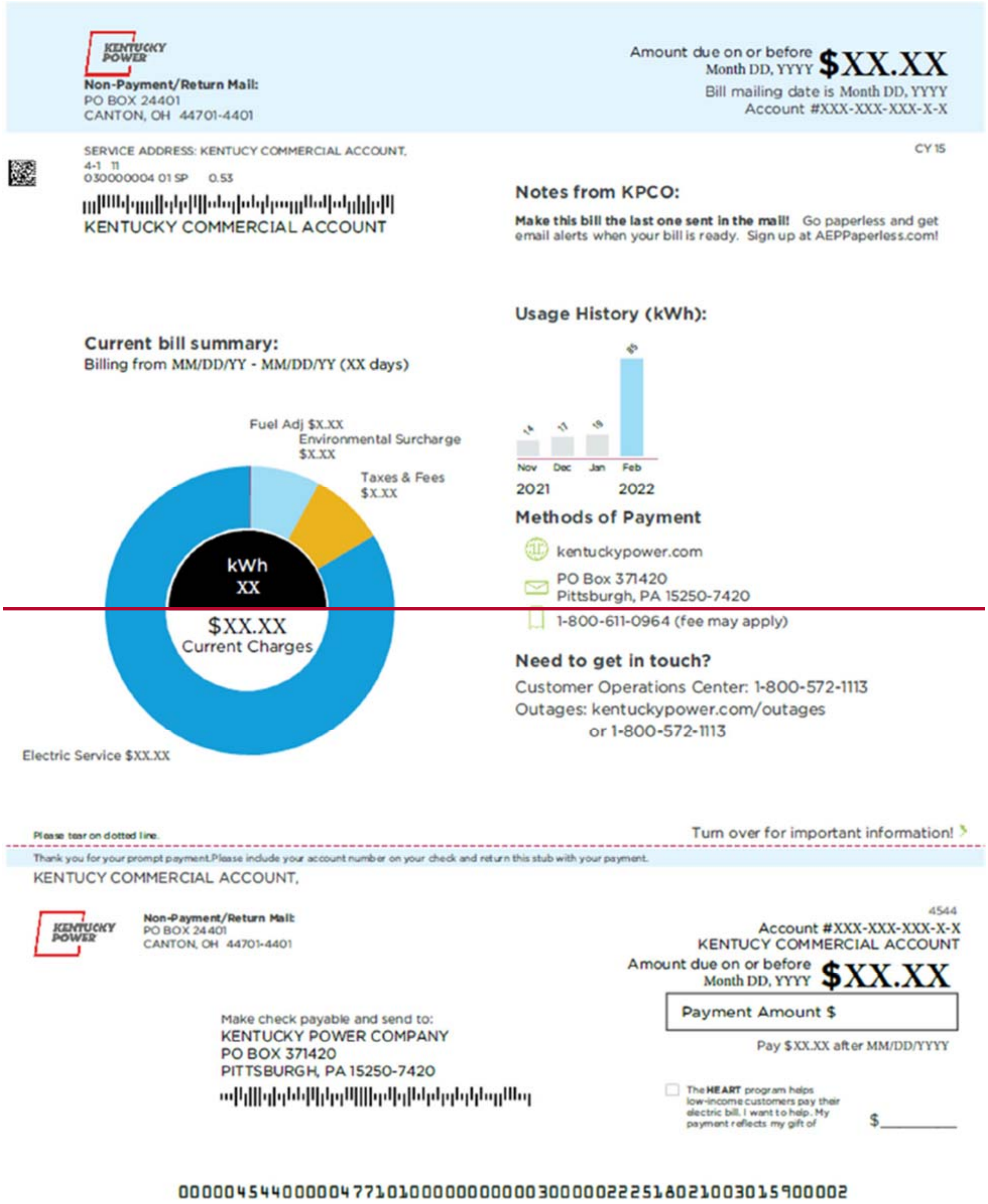
Total usage for the past 12 months: X,XXX kWh

Average (Avg.) monthly usage: XXX kWh

Continued on Sheet 2-16

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued


KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before Month DD, YYYY $XX.XX
Bill mailing date is Month DD, YYYY
Account #XXX-XXX-XXX-X-X

SERVICE ADDRESS: KENTUCY COMMERCIAL ACCOUNT,
4-1 11
030000004 01 SP 0.53
KENTUCKY COMMERCIAL ACCOUNT

CY 15

Notes from KPCO:

Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at AEPPaperless.com!

Usage History (kWh):

Nov Dec Jan Feb
2021 2022

Current bill summary:
Billing from MM/DD/YY - MM/DD/YY (XX days)

Fuel Adj $X.XX
Environmental Surcharge $X.XX
Taxes & Fees $X.XX
kWh XX
$XX.XX Current Charges
Electric Service $XX.XX

Methods of Payment

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Need to get in touch?

Customer Operations Center: 1-800-572-1113
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.
Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCY COMMERCIAL ACCOUNT,

KENTUCKY POWER
Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

4544
Account #XXX-XXX-XXX-X-X
KENTUCY COMMERCIAL ACCOUNT
Amount due on or before Month DD, YYYY $XX.XX

Payment Amount $

Pay $XX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420
PITTSBURGH, PA 15250-7420

The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

00000454400000477101000000000003000002225180210030159000002

DATE OF ISSUE: June 29, 2023
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TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XXX.XX**

Bill mailing date is MM DD, YYYY
Account #XXX–XXX–XXX–X–X

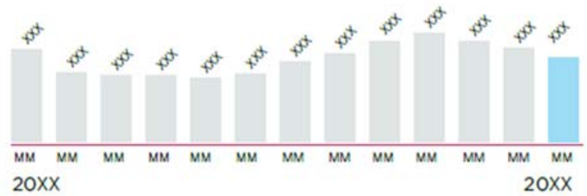
SERVICE ADDRESS: KENTUCKY GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX–XXXX

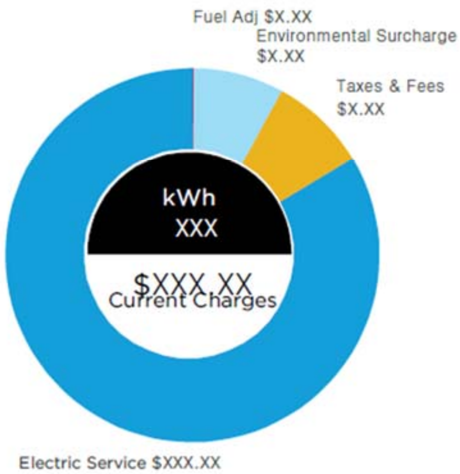
KENTUCKY GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX–XXXX

Notes from KPCO:

Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

Usage History (kWh):





Methods of Payment

kentuckypower.com

PO Box 371420
Pittsburgh, PA 15250-7420

1-800-611-0964 (fee may apply)

Need to get in touch?

Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line. Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX–XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY GENERAL SERVICE

Amount due on or before MM DD, YYYY **$XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250–7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

Continued on Sheet 2-17

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

Service Address:

GENERAL SERVICE
10 MEDIUM RD
MEDIUM, KY 41701

Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount due at last billing	$	XXX.XX
Payment MM/DD/YY - Thank You		-XXX.XX
Previous Balance Due	$	X.XX
Current KPCO Charges		
Tariff 211 - Small General Service MM/DD/YY		
Rate Billing	$	XXX.XX
Federal Tax Cut Credit @ X.XXXXXXX		-X.XX
Fuel Adj @ X.XXXXXXX Per kWh		XX.XX
DSM Adj @ X.XXXXXXX Per kWh		XX.XX
Capacity Charge @ X.XXXXXXX Per kWh		XX.XX
Kentucky Economic Development Surcharge @ $X.XX		XX.XX
Environmental Adj X.XXXXXXX%		X.XX
Decommissioning Rider X.XXXXXXX%		XX.XX
Purchase Power Adj @X.XXXXXXX Per kWh		XX.XX
Renewable Power Option Rider		X.XX
School Tax		X.XX
Franchise Tax		X.XX
State Sales Tax		X.XX
Current Balance Due	$	XXX.XX
Total Balance Due	$	XXX.XX

Usage Details:

Values reflect changes between current month and previous month.

Total usage for the past 12 months: X,XXX kWh
Your average monthly usage: XXX kWh

Meter Details:

Meter #123456789					
Previous	Type	Current	Type	Metered	Usage
XXXXX	Actual	XXXXX	Actual	X,XXX	X,XXX kWh
Service Period MM/DD - MM/DD				Multiplier X.XXXXXX	
Next scheduled read date should be between MM/DD and MM/DD.					

Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

DATE OF ISSUE: June 29, 2023
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ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER

Service Address:

KENTUCKY GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX
Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX.XX
Payment XX/XX/XX - Thank You		-XX.XX
Previous Balance Due	**$**	**X.XX**
Current KPCO Charges		
Tariff XXX - General Service XX/XX/XX		
Rate Billing	$	XX.XX
Federal Tax Change @ X.XXXXX- Per kWh		-XX.XX
Fuel Adj @ X.XXXXX Per kWh		XX.XX
DSM Adj @ X.XXXXX Per kWh		XX.XX
Kentucky Economic Development Surcharge @ $X.XX		XX.XX
Distribution Reliability Rider @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Renewable Power Option Rider		XX.XX
Securitization Financing Rider X.XXXXX%		XX.XX
Decommissioning Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		XX.XX
School Tax		XX.XX
City's Franchise Fee		XX.XX
State Sales Tax		XX.XX
Current Balance Due	**$**	**XX.XX**

Meter Read Details:

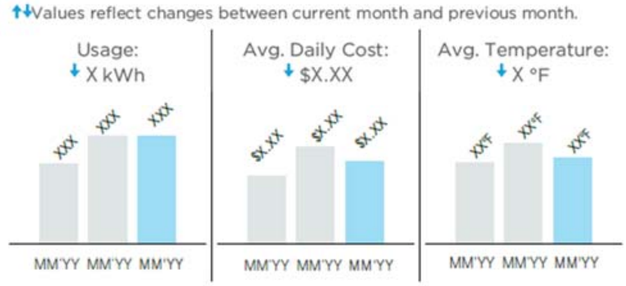
Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
XXX	Actual	XXX	Actual	XXX	XXX kWh
Service Period XX/XX - XX/XX					Multiplier 1
Next scheduled read date should be between MM DD and MM DD.					

Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: XXX kWh
Average (Avg.) monthly usage: XXX kWh

Continued on Sheet 2-18

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DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER
Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before Month DD, YYYY **$X,XXX.XX**
Bill mailing date is Month DD, YYYY
Account #XXX-XXX-XXX-X-X

SERVICE ADDRESS: INDUSTRIAL TEST CASE,
5

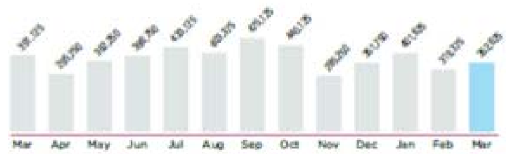
CY 11

INDUSTRIAL TEST CASE

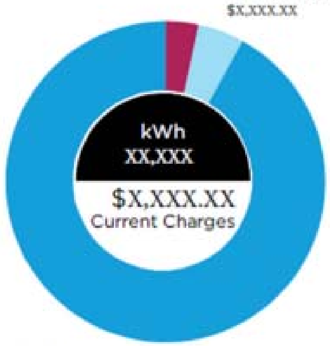
Notes from KPCO:

Thank you for being a paperless customer! Sign up for billing and outage alerts to stay informed. You can manage your account by logging in at kentuckypower.com.

Usage History (kWh):



Current bill summary:
Billing from XX/XX/XX - XX/XX/XX (XX days)



Methods of Payment

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Need to get in touch?

Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.

Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

INDUSTRIAL TEST CASE,

KENTUCKY POWER
Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

2340604
Account #XXX-XXX-XXX-X-X

Amount due on or before Month DD, YYYY **$X,XXX.XX**

Payment Amount $

Pay $X,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420
PITTSBURGH, PA 15250-7420

The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

002340604002457634010000000000003000003924150302040119000005

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TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX – XXX – XXX – X – X

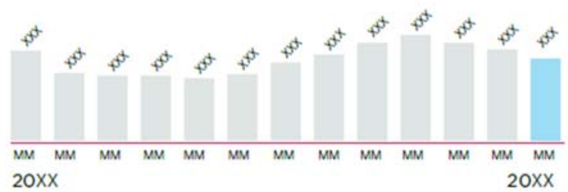
SERVICE ADDRESS: KENTUCKY LARGE GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX – XXXX

KENTUCKY LARGE GENERAL SERVICE
ADDRESS 123
ABC, KY XXXXX – XXXX

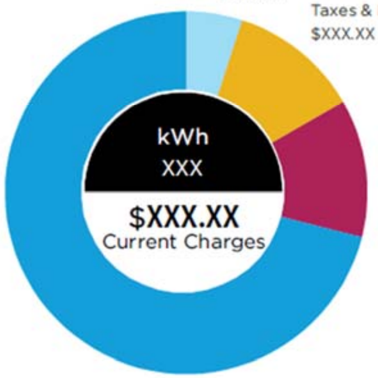
Notes from KPCO:

Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

Usage History (kWh):



Current bill summary:
Billing from MM/DD/YY - MM/DD/YY (XX days)



Methods of Payment

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Need to get in touch?

Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.
Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY LARGE GENERAL SERVICE, ADDRESS 123, ABC, KY XXXXX – XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY LARGE GENERAL SERVICE
Amount due on or before MM DD, YYYY **$XXX.XX**

Payment Amount $

Pay $XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250 – 7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

Continued on Sheet 2-19

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

LARGE GENERAL SERVICE
170 LARGE WAY DRIVE
LARGERSVILLE, KY 41465

Account #XXX-XXX-XXX-X-X

Line Item Charges:

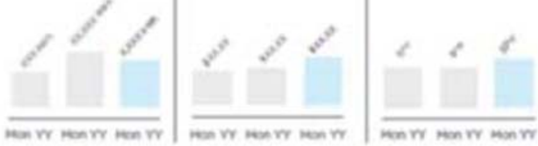
Previous Charges		
Total Amount due at last billing	$	XXX.XX
Payment MM/DD/YY - Thank You		-XXX.XX
Previous Balance Due	**$**	**X.XX**

Current KPCO Charges		
Tariff 240 - Large General Service MM/DD/YY		
Rate Billing	$	XXX.XX
Federal Tax Cut Credit @ X.XXXXXXX		-X.XX
Economic Development Rider - IBDD		XX.XX
Economic Development Rider - SBDD		XX.XX
Fuel Adj @ X.XXXXXX Per kWh		XX.XX
Kentucky Economic Development Surcharge @ X.XX		XX.XX
DSM Adj. @ X.XXXXXX Per kWh		XX.XX
Capacity Charge @ X.XXXXXX Per kWh		XX.XX
Environmental Adj XX.XXXXX%		X.XX
Decommissioning Rider X.XXXXX%		XX.XX
Purchased Power Adj @ X.XXXXX Per kWh		XX.XX
Renewable Power Option Rider		XX.XX
School Tax		XX.XX
Franchise Tax		XX.XX
State Sales Tax		X.XX
Current Balance Due	**$**	**XXX.XX**
Total Balance Due	**$**	**XXX.XX**

Usage Details:

Values reflect changes between current month and previous month.

Usage History: X,XXX kWh | Avg. Daily Cost: $X.XX | Avg. Temperature: 1°



Total usage for the past 12 months: XXX,XXX kWh
Your Average Monthly Usage: XX,XXX kWh

Billed Usage MM/DD				
Usage	Power Factor	Power Factor Constant	Meter Location Comp	Billed Usage
	(X.X.X)	(X.XXX)		
XX,XXX	-	-	-	XX,XXX kWh
XX,XXX	-	-	-	XX.XXX kWh
XX,XXX	-	-	-	XX,XXX kvarh

Meter Details:

Meter #123456789					
Prev	Type	Current	Type	Metered	Usage
XX,XXX	Actual	XX,XXX	Actual	XX,XXX	XX,XXX kWh
-	Actual	-	Actual	XXX.XXX	XXX.XXX kW
XXXX	Actual	XXXX	Actual	XX,XXX	XX,XXX kvarh
Service Period MM/DD - MM/DD			Multiplier XX.XXXXXX		
Next scheduled read date should be between Month DD and Month DD.					

Notes from KPCO:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/account/bills/rates/. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER

Service Address:

KENTUCKY LARGE GENERAL SERVICE

ADDRESS 123
ABC, KY XXXXX – XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX	-	-	-	XXXX kWh
XXX	-	-	-	XXX kW
XXX	-	-	-	XXX.XXX KVA

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XXX.XX
Payment XX/XX/XX - Thank You		-XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Charges		

Tariff XXX - Large General Service XX/XX/XX		
Rate Billing	$	XXX.XX
Economic Development Rider - IBDD		-XXX.XX
Economic Development Rider - SBDD		-XXX.XX
Federal Tax Change @ X.XXXXX- Per kWh		-XXX.XX
Fuel Adj @ X.XXXXX Per kWh		XXX.XX
DSM Adj @ X.XXXXX Per kWh		XXX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Distribution Reliability Rider @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XXX.XX
Renewable Power Option Rider		XXX.XX
Securitization Financing Rider X.XXXXX%		XX.XX
Decommissioning Rider X.XXXXX%		XXX.XX
Envrionmental Adj. X.XXXXX%		XXX.XX
School Tax		XXX.XX
City's Franchise Fee		XXX.XX
State Sales Tax		XXX.XX
Current Balance Due	**$**	**XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
Service Period MM/DD - MM/DD					Multiplier XXX
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

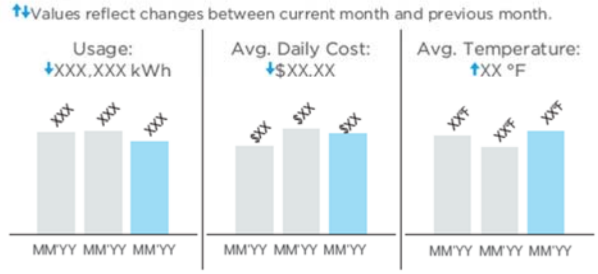
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acclunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: XXX kWh

Average (Avg.) monthly usage: XXX kWh

Continued on Sheet 2-20

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XX,XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX-XXX-XXX-X-X

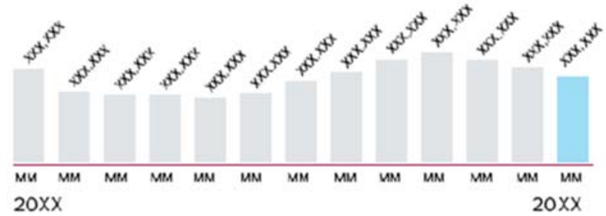
SERVICE ADDRESS: KENTUCKY INDUSTRIAL, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY INDUSTRIAL
ADDRESS 123
ABC, KY XXXXX-XXXX

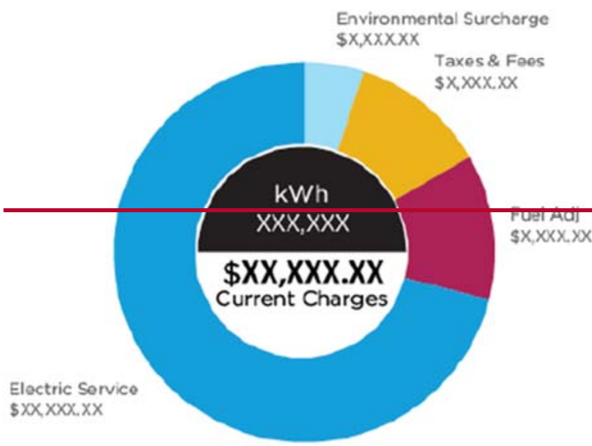
Notes from KPCO:

Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

Usage History (kWh):



Current bill summary:
Billing from MM/DD/YY - MM/DD/YY (XX days)



Methods of Payment

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Need to get in touch?

Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.
Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.

KENTUCKY INDUSTRIAL, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY INDUSTRIAL

Amount due on or before MM DD, YYYY **$XX,XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250-7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

DATE OF ISSUE: June 29, 2023
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ISSUED BY: /s/ Brian K. West
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In Case No.: 2023-00159 Dated XXXX XX, XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XX,XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX-XXX-XXX-X-X

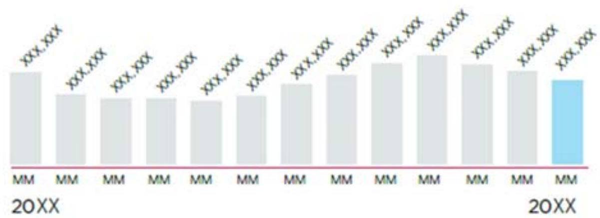
SERVICE ADDRESS: KENTUCKY INDUSTRIAL–PRIMARY & SECONDARY, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY INDUSTRIAL– PRIMARY & SECONDARY
ADDRESS 123
ABC, KY XXXXX-XXXX

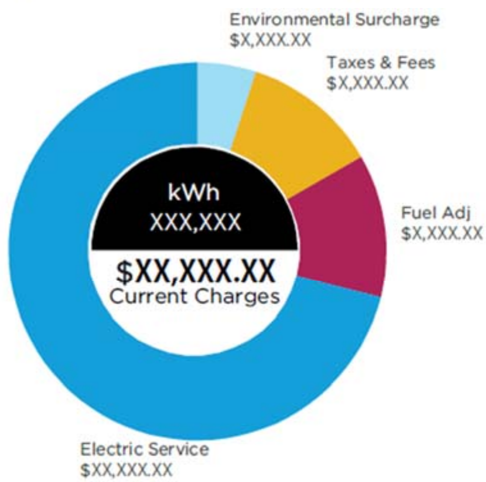
Notes from KPCO:

Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

Usage History (kWh):



Current bill summary:
Billing from MM/DD/YY - MM/DD/YY (XX days)



Methods of Payment

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Need to get in touch?
Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.
Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.
KENTUCKY INDUSTRIAL–PRIMARY & SECONDARY, ADDRESS 123, ABC, KY XXXXX-XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY INDUSTRIAL – PRIMARY & SECONDARY
Amount due on or before MM DD, YYYY **$XX,XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250-7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $________

Continued on Sheet 2-21

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL–PRIMARY & SECONDARY

ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX.XXX	-	-	-	XXX.XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk
				High Prev Demand = X,XXX.X Off-Pk

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Charges		
Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Change @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Distribution Reliability Rider @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitization Financing Rider X.XXXXX%		XX.XX
Decommissioning Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		X,XXX.XX
School Tax		X,XXX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD					Multiplier XXX
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

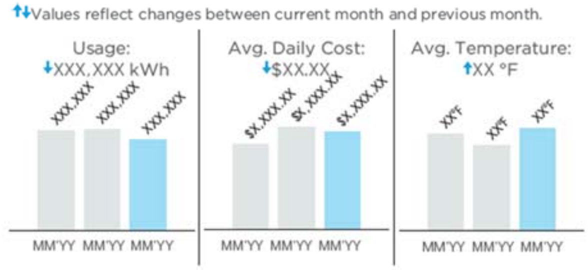
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh

Average (Avg.) monthly usage: XXX,XXX kWh

Continued on Sheet 2-22

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

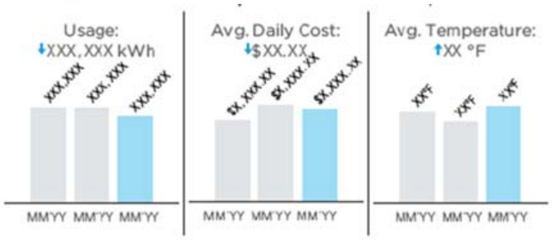
KENTUCKY INDUSTRIAL
ADDRESS 123
ABC, KY XXXXX - XXXX
Account #XXX-XXX-XXX-X-X

Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment 04/28/22 - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Liberty Charges		
Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Credit @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Capacity Charge @ X.XXXXX Per kWh		XXX.XX
~~Purchased Power Adj. $X.XXXXX/kWh~~		~~XX.XX~~
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Decommissioning Rider X.XXXXX%		XX.XX
Environmental Adj. X.XXXXX%		X,XXX.XX
School Tax		X,XXX.XX
Franchise Tax		X,XXX.XX
State Sales Tax		X,XXX.XX
Current Balance Due	**$**	**XX,XXX.XX**
Total Balance Due Pay $XX,XXX.XX after MM/DD/YYYY	$	XX,XXX.XX

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh
Average (Avg.) monthly usage: XXX,XXX kWh

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX,XXX	-	-	-	XXX,XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk High Prev Demand = X,XXX.X Off-Pk

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
~~Service Period MM/DD - MM/DD~~			~~Multiplier XXX~~		
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

Notes from Kentucky Power:

If you are an AutoPay customer, we will continue to process your monthly AutoPay withdrawals. If you do not wish to continue AutoPay, please log in to your electric account on our website and select Manage AutoPay to un-enroll.

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1-800-572-1113.

Due date does not apply to previous balance due.

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Amount due on or before MM DD, YYYY **$XX,XXX.XX**
Bill mailing date is MM DD, YYYY
Account #XXX–XXX–XXX–X–X

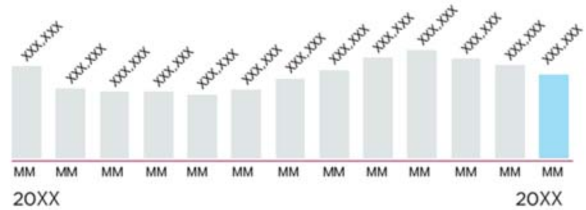
SERVICE ADDRESS: KENTUCKY INDUSTRIAL–SUBTRANSMISSION & TRANSMISSION, ADDRESS 123, ABC, KY XXXXX–XXXX

KENTUCKY INDUSTRIAL–
SUBTRANSMISSION & TRANSMISSION
ADDRESS 123
ABC, KY XXXXX–XXXX

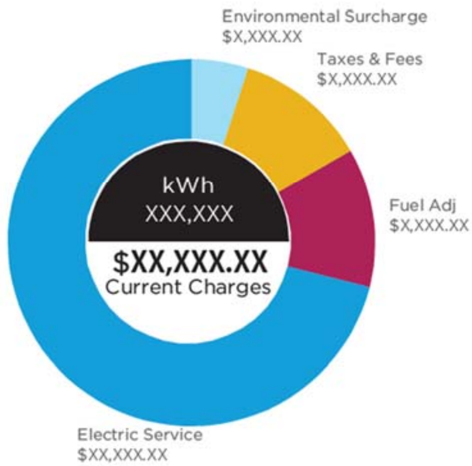
Notes from KPCO:

Make this bill the last one sent in the mail! Go paperless and get email alerts when your bill is ready. Sign up at kentuckypower.com/paperless!

Usage History (kWh):



Current bill summary:
Billing from MM/DD/YY - MM/DD/YY (XX days)



Methods of Payment

kentuckypower.com
PO Box 371420
Pittsburgh, PA 15250-7420
1-800-611-0964 (fee may apply)

Need to get in touch?
Customer Operations Center: 1-888-710-4237
Outages: kentuckypower.com/outages
or 1-800-572-1113

Please tear on dotted line.

Turn over for important information!

Thank you for your prompt payment. Please include your account number on your check and return this stub with your payment.
KENTUCKY INDUSTRIAL–SUBTRANSMISSION & TRANSMISSION, ADDRESS 123, ABC, KY XXXXX–XXXX

KENTUCKY POWER

Non-Payment/Return Mail:
PO BOX 24401
CANTON, OH 44701-4401

Account #XXX-XXX-XXX-X-X
KENTUCKY INDUSTRIAL – SUBTRANSMISSION & TRANSMISSION
Amount due on or before MM DD, YYYY **$XX,XXX.XX**

Payment Amount $

Pay $XX,XXX.XX after MM/DD/YYYY

Make check payable and send to:
KENTUCKY POWER COMPANY
PO BOX 371420 PITTSBURGH,
PA 15250–7420

☐ The **HEART** program helps low-income customers pay their electric bill. I want to help. My payment reflects my gift of $__________

Continued on Sheet 2-23

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Terms and Conditions of Service Continued

KENTUCKY POWER

Service Address:

KENTUCKY INDUSTRIAL–
SUBTRANSMISSION AND TRANSMISSION
ADDRESS 123
ABC, KY XXXXX–XXXX

Account #XXX-XXX-XXX-X-X

Billed Usage MM/YY				
Usage	Power Factor	Power Factor Constant	Meter Location Comp.	Billed Usage
XXX.XXX	-	-	-	XXX.XXX kWh
XXX.XXX	-	-	-	XXX.XXX kW On-Pk
XXX.XXX	-	-	-	XXX.XXX kW Off-Pk
Contract Capacity = X,XXX.X				High Prev Demand = X,XXX.X On-Pk High Prev Demand = X,XXX.X Off-Pk

Previous Charges		
Total Amount Due At Last Billing	$	XX,XXX.XX
Payment XX/XX/XX - Thank You		-XX,XXX.XX
Previous Balance Due	**$**	**XX.XX**
Current Charges		

Tariff XXX - Industrial General Service XX/XX/XX		
Rate Billing	$	XX,XXX.XX
Economic Development Rider - IBDD		-X,XXX.XX
Economic Development Rider - SBDD		-X,XXX.XX
Federal Tax Change @ X.XXXXX- Per kWh		-X,XXX.XX
Fuel Adj @ X.XXXXX Per kWh		X,XXX.XX
Kentucky Economic Development Surcharge @ $X.XX		X.XX
Purchased Power Adj. $X.XXXXX/kWh		XX.XX
Purchased Power Adj. $X.XXXXX/kW		X,XXX.XX
Renewable Power Option Rider		X,XXX.XX
Securitization Financing Rider X.XXXXX%		XX.XX
Decommissioning Rider X.XXXXX%		XX.XX
Envrionmental Adj. X.XXXXX%		X,XXX.XX
School Tax		X,XXX.XX
City's Franchise Fee		X,XXX.XX
State Sales Tax		X,XXX.XX
Total Balance Due	**$**	**XX,XXX.XX**

Meter Read Details:

Meter #XXXXXXXXX					
Previous	Type	Current	Type	Metered	Usage
X	X	X.XXX	Actual	X	X kVAR
X	X	X.XXX	Actual	X.XXX	XXX.XX kW On-Pk
XXXXX	Actual	XXXXX	Actual	XXX	XXX,XXX kWh
X	X	X.XXX	Actual	X.XX	XXX.X kW Off-Pk
X	X	X.XXX	Actual	X.XXX	XXX.XX kVAR
Service Period MM/DD - MM/DD					Multiplier XXX
Next scheduled read date should be between MM DD and MM DD.					

Net Usage : XXX,XXX kWh Billable Usage: XXX,XXX kWh

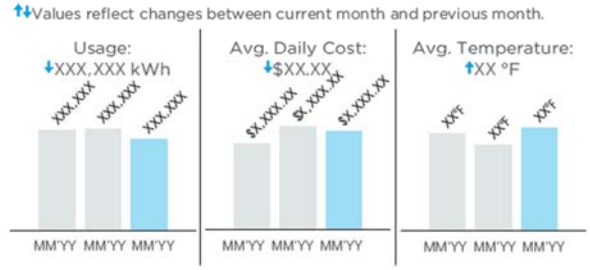
Notes from Kentucky Power:

Kentucky Power provides online access to customer rate schedules at https://kentuckypower.com/acciunt/bills/rates. You can access a copy of your rates by clicking the "Kentucky Tariffs" link at that website. You can also view rates at our office, or request that a copy be sent to you via U.S. Postal Service or via email by calling customer service at 1–800–572–1113.

Due date does not apply to previous balance due.

Usage Details:

↑↓Values reflect changes between current month and previous month.



Total usage for the past 12 months: X,XXX,XXX kWh
Average (Avg.) monthly usage: XXX,XXX kWh

Capacity and Energy Control Program

Introduction
Kentucky Power Company's Capacity and Energy Control Program outlines the procedures the Company will follow in the event of an emergency that threatens the continued reliable operation of bulk power supply system. Notwithstanding any provisions of this Capacity and Energy Control Program, the Company shall have the right to take whatever steps, with or without notice and without liability on Company's part, that Company believes necessary, in whatever order consistent with good utility practices and not on an unduly discriminatory basis, to preserve system integrity and to prevent the collapse of Company's electric system or interconnected electric network or to restore service following an outage. Such actions will be taken giving priority to maintaining service to Company's retail and full requirements customers relative to other sales whenever feasible and as allowed by law. The Company's Capacity and Energy Control Program consists of three sets of procedures:

I. Procedures During Abnormal System Frequency
II. Capacity Deficiency Program
III. Energy Emergency Control Program

Specific details regarding the Company's Capacity and Energy Control Program are included in the Company's Emergency Operating Plan ("EOP"). A copy of the Company's current EOP is on file with the Kentucky Public Service Commission in Administrative Case No. 345. Where this tariff diverts from the Company's EOP, the EOP Plan shall govern.

I. AEP/PJM Procedures During Abnormal System Frequency (EOP Section IV)

a. Purpose
Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP/PJM program described below provides procedures for reducing the consumption of electric energy on the Company's system in the event of a period of abnormal system frequency.

b. AEP/PJM Procedures
From 59.8 – 60.2 Hz, to the extent practicable, the Company will utilize all operating and emergency reserves. The manner of utilization of these reserves depends on the behavior of the System during the emergency.

For rapid frequency decline, the Company will utilize capacity that is on-line and automatically responsive to frequency (spinning reserve) and such measures as interconnection assistance and automatic load reductions to arrest the decline in frequency.

If the frequency decline is gradual, the Generation/Production Optimization Group, particularly in the deficient area, will invoke non-automatic procedures involving operating and emergency reserves. These efforts will continue until the frequency decline is arrested or until automatic load-shedding devices operate at subnormal frequencies. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities. At 59.75 Hz, the Company will suspend Automatic Generation Control (AGC) and notify Interruptible Customers to drop load.

If at any time the decline in area frequency is arrested below 59.5 Hz, the Company will evaluate whether the area should manually shed an additional 5% of its initial load. If, after five minutes, shedding 5% of load has not returned the area frequency to 59.5 Hz or above, the area shall manually shed an additional 5% of its remaining load and continue to repeat in five-minute intervals until 59.5 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units that are discussed in the EOP subsection titled, "Isolation of Coal-fired Generating Units."

Automatic Load Shedding Program details are located in Section IV of the Company's EOP.

Continued on Sheet 3-2

Capacity and Energy Control Program Continued

II. Capacity Deficiency Program (EOP Section III)

a. Purpose
The purpose of the Capacity Deficiency Program is to provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power (AEP) East/PJM Eastern System in the event of a capacity deficiency. A capacity deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements.

b. AEP East/PJM Procedures
There are three general levels of emergency actions for capacity deficiencies:

- Alerts - issued in advance of the operating day for elevated awareness and to give time for advanced preparations.
- Warnings - issued real time, typically preceding, and with an estimated time/window for a potential future action.
- Actions - issued real time and requires PJM and/or Member response. PJM actions are consistent with NERC and RFC EOP standards.

The Company may also issue an Advisory, one or more days in advance of the operating day during which a capacity deficiency may occur, that are general in nature and are for elevated awareness only. No preparations or actions are required in response to an Advisory.

Alerts

Voluntary Customer Load Curtailment Alert
The purpose of the Voluntary Customer Load Curtailment Alert is to alert members of the probable future need to implement a voluntary customer load curtailment. It is implemented whenever the estimated operating reserve capacity indicates a probable future need for voluntary customer load curtailment.

Real Time Emergency Procedures (Warnings and Actions)

Warnings
Warnings are issued in real time during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. Generally, a warning precedes an associated action. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO.

Actions
The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- loading generation that is restricted for reasons other than cost
- recalling non-capacity backed off-system sales
- purchasing emergency energy from participants / surrounding pools
- load relief measures

The Company's EOP includes a nine-step warning and action procedure during capacity deficiency conditions.

Continued on Sheet 3-3

Capacity and Energy Control Program Continued

c. Priority Levels
For the purpose of these capacity deficiency procedures, the following Priority Levels for loads have been established:

I. Essential Health and Safety Uses – to be given special consideration in these procedures shall, insofar as the situation permits, include the following types of use:

a. Hospitals, which shall be limited to institutions providing medical care to patients.

b. Life Support Equipment, which shall be limited to kidney machines, respirators, and similar equipment used to sustain the life of a person.

c. Police Stations and Government Detention Institutions, which shall be limited to essential uses required for police activities and the operation of facilities used for the detention of persons.

d. Fire Stations, which shall be limited to facilities housing mobile fire-fighting apparatus.

e. Communication Services, which shall be limited to essential uses required for telephone, telegraph, television, radio and newspaper operations, and operation of state and local emergency services.

f. Water and Sewage Services, which shall be limited to essential uses required for the supply of water to a community, flood pumping and sewage disposal.

g. Transportation and Defense-related Services, which shall be limited to essential uses required for the operation, guidance control and navigation of air, rail and mass transit systems, including those uses essential to the national defense and operation of state and local emergency services. These uses shall include essential services such as street, highway and signal-lighting.

Although, when practical, these types of uses will be given special consideration when implementing the manual load- shedding provisions of this program, any customer may be affected by rotating or unplanned outages and should install emergency generation equipment if continuity of service is essential. Where the emergency is system-wide in nature, consideration will be given to the use of rotating outages as operationally practicable. In case of customers supplied from two utility sources, only one source will be given special consideration. Also, any other customers who, in their opinion, have critical equipment should install emergency generation equipment.

Company maintains lists of customers with life support equipment and other critical needs for the purpose of curtailments and service restorations. Company, lacking knowledge of changes that may occur at any time in Customer's equipment, operation, and backup resources, does not assume the responsibility of identifying customers with priority needs. It shall, therefore, be Customer's responsibility to notify Company if Customer has critical needs.

II. Critical Commercial and Industrial Uses – Except as described in Section C.III below, these uses shall include commercial or industrial operations requiring regimented shutdowns to prevent conditions hazardous to the general population, and to energy utilities and their support facilities critical to the production, transportation, and distribution of service to the general population. Company shall maintain a list of such customers for the purpose of curtailments and service restoration.

III. Residential Use – Residential use during certain weather conditions (for example severe winter weather) will receive precedence over critical commercial and industrial uses. The availability of Company service personnel and the circumstances associated with the outage will also be considered in the restoration of service.

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Capacity and Energy Control Program Continued

Priority Levels Continued

IV. Non-critical commercial and industrial uses.

V. Nonessential Uses – The following and similar types of uses of electric energy shall be considered nonessential for all customers:

a. Outdoor flood and advertising lighting, except for the minimum level to protect life and property, and a single illuminated sign identifying commercial facilities when operating after dark.

b. General interior lighting levels greater than minimum functional levels.

c. Show-window and display lighting.

d. Parking lot lighting above minimum functional levels.

e. Energy use to lower the temperature below 78 degrees during operation of cooling equipment and above 65 degrees during operation of heating equipment.

f. Elevator and escalator use in excess of the minimum necessary for non-peak hours of use.

g. Energy use greater than that which is the minimum required for lighting, heating, or cooling of commercial or industrial facilities for maintenance cleaning or business-related activities during non-business hours.

Non-jurisdictional customers will be treated in a manner consistent with the curtailment procedures contained in the service agreement between the parties or the applicable tariff.

d. Curtailment Procedures
In the event Company's load exceeds internal generation, transmission, or distribution capacity, or other system disturbances exist, and internal efforts have failed to alleviate the problem, including emergency energy purchases, the following steps may be taken, individually or in combination, in the order necessary as time permits:

1. Customers having their own internal generation capacity will be curtailed, and customers on interruptible contracts will be curtailed for the maximum hours and load allowable under their contract. Nothing in this procedure shall limit Company's rights under the Contract Service – Interruptible Power Tariff or the Alternate Feed Service Rider.

2. Power output will be maximized at Company's generating units.

3. Company use of energy at its generating stations will be reduced to a minimum.

4. Company's use of electric energy in the operation of its offices and other facilities will be reduced to a minimum.

5. The Kentucky Public Service Commission will be advised of the situation.

6. An appeal will be made to customers through the news media and/or personal contact to voluntarily curtail as much load as possible. The appeal will emphasize the defined priority levels as set forth above.

7. Customers will be advised through the use of the news media and personal contact that load interruption is imminent.

8. Implement procedures for interruption of selected distribution circuits.

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Capacity and Energy Control Program Continued

e. Service Restoration Procedures
Where practical, priority uses will be considered in restoring service and service will be restored in the order I through V as defined under Priority Levels described above. However, because of the varieties of unpredictable circumstances which may exist or precipitate outages, it may be necessary to balance specific individual needs with infrastructure needs that affect a larger population. When practical, Company will attempt to provide estimates of repair times on its website to aid customers in assessing the need for alternative power sources and temporary relocations.

III. Energy Emergency Control Program (EOP Section V)

a. Introduction
The purpose of this plan is to provide for the reduction of the consumption of electric energy on the American Electric Power Company System in the event of a severe coal fuel shortage, such as might result from a general strike, or severe weather.

b. Procedures
In the event of a potential severe coal shortage, such as one resulting from a general coal strike, the following steps will be implemented. These steps will be carried out to the extent permitted by contractual commitments or by order of the regulatory authorities having jurisdiction. For further information, see EOP Section V.

With regard to mandatory curtailments, the Company proposes to monitor compliance after the fact. A customer exceeding his electric allotment would be warned to curtail his usage or face, upon continuing noncompliance and upon one day's actual written notice, disconnection of electric service for the duration of the energy emergency.

Standard Nominal Voltages

The voltage available to any individual customer shall depend upon the voltage of the Company's lines serving the area in which customer is provided service.

Electric service provided under the Company's rate schedules will be 60 hertz alternating current delivered from various load centers at nominal voltages and phases as available in a given location as follows:

Secondary Distribution Voltages

Residential Service

Single phase 120/240 volts three wire or 120/208 volts three wire on network system.

General Service - All Except Residential

Single-phase 120/240 volts three wire or 120/208 volts three wire on network system. Three-phase 120/208 volts four wire on network system, 120/240 volts four wire, 240 volts three wire, 480 volts three wire and 277/480 volts four wire, Single-phase 480 volts two wire, and Single-phase 240/480 volts three wire.

Primary Distribution Voltages

The Company's primary distribution voltage levels at load centers are 2,400; 4,160Y; 7,200; 12,470Y; 19,900 and 34,500Y.

Subtransmission Line Voltages

The Company's sub transmission voltage levels are 34,500; 46,000; and 69,000.

Transmission Line Voltages

The Company's transmission voltage levels are 138,000; 161,000; 345,000; and 765,000.

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Tariff R.S.
(Residential Service)

Availability of Service
Available for full domestic electric service through 1 (one) meter to individual residential customers including rural residential customers engaged principally in agricultural pursuits.

Rate *(Tariff Codes 015, 017, 022)*

Service Charge	$20~~17~~.00~~50~~	per month
Energy Charge	12~~0~~.947~~799~~¢	per kWh

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Residential Energy Assistance~~	~~Sheet No. 25~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~Due Date~~
~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date.~~

Volunteer Departments *(Tariff Code 024)*
Volunteer Fire Departments may qualify pursuant to KRS 278.172 for this tariff but will be required to provide a completed Form 990 and update it annually.

Optional Seasonal Provision *(Tariff Code XXX)*
For residential customers desiring to take seasonal rate service. Service under this provision shall be for a minimum of 12 consecutive billing months.

Service Charge	$20.00	per month
Energy Charge All kWh used during winter billing months (December-March)	11.947¢	per kWh

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All kWh used during all other months (April-November)	13.762¢	per kWh

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clause section.

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Tariff R.S. Continued
(Residential Service)

Storage Water Heating Provision
This provision is withdrawn except for the present installations of current customers receiving service hereunder at premises served prior to April 1, 1997.

If the customer installs a Company approved storage water heating system which consumes electrical energy only during off-peak hours as specified by the Company and stores hot water for use during on-peak hours, the following shall apply:

Tariff Code			
012	For Minimum Capacity of 80 gallons, the last 300 kWh of use in any month shall be billed at	8~~7~~.603 ~~888~~¢	per kWh
013	For Minimum Capacity of 100 gallons, the last 400 kWh of use in any month shall be billed at	8~~7~~.603 ~~888~~¢	per kWh
014	For Minimum Capacity of 120 gallons or greater, the last 500 kWh of use in any month shall be billed at	8~~7~~.603 ~~888~~¢	per kWh

These provisions, however, shall in no event apply to the first 200 KWH used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For purpose of this provision, the on-peak billing period is defined as 7:00A.M. to 9:00P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00PM to 7:00AM for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the storage water heating system and devices which qualify the residence for service under the storage water heater provision, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds that in its sole judgment the availability conditions of this provision are being violated, it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

Load Management Water-Heating Provision *(Tariff Code 011)*
For residential customers who install a load management water-heating system which consumes electrical energy during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 kWh of use in any month shall be billed at 8~~7~~.603~~888~~¢ per kWh.

This provision, however, shall in no event apply to the first 200 kWh used in any month, which shall be billed in accordance with the "Monthly Rate" as set forth above.

For the purpose of this provision, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

The Company reserves the right to inspect at all reasonable times the load management water-heating system(s) and devices which qualify the residence for service under the Load Management Water-Heating Provision. If the Company finds that, in its sole judgment, the availability conditions of this provision are being violated; it may discontinue billing the Customer under this provision and commence billing under the standard monthly rate.

This provision is subject to the Service Charge, and the adjustment clauses as stated in the Adjustment Clauses section.

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Tariff R.S. Continued
(Residential Service)

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This service is available to rural domestic customers engaged principally in agricultural pursuits where service is taken through one meter for residential purposes as well as for the usual farm uses outside the home, but it is not extended to operations of a commercial nature or operations such as processing, preparing or distributing products not raised or produced on the farm, unless such operation is incidental to the usual residential and farm uses.

The Company shall have the option of reading meters monthly or bimonthly and rendering bills accordingly. When bills are rendered bimonthly, the minimum charge and the quantity of KWH in each block of the rates shall be multiplied by two.

Pursuant to 807 KAR 5:041, Section 11, paragraph (1), of Public Service Commission Regulations, the Company will make an extension of 1,000 feet or less to its existing distribution line without charge for a prospective permanent residential customer served under this R.S.Tariff. Pursuant to 807 KAR 5:041 Section 12 extensions of up to 150 feet for a mobile home are provided without charge.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement.

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Tariff R.S.-L.M.-T.O.D.
(Residential Service Load Management Time of Day)

Availability of Service

Available to customers eligible for Tariff R.S. (Residential Service) who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours.

Households eligible to be served under this tariff shall be metered through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods.

Rate *(Tariff Codes 028, 030, 032, 034)*

Service Charge	$2~~1~~3.00	per month
Energy Charge All kWh used during on-peak billing period	18~~4~~.646~~534~~¢	per kWh
All kWh used during off-peak billing period	8~~7~~.603~~888~~¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Conservation and Load Management Credit

For the combination of an approved electric thermal storage space heating system and water heater, both of which are designed to consume electrical energy only between the hours of 9:00P.M. and 7:00A.M. for all days of the week, each residence will be credited 0.745¢ per kWh for all energy used during the off-peak billing period, for a total of 60 monthly billing periods following the installation and use of these devices in such residence.

Minimum Charge

This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

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Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Residential Energy Assistance~~	~~Sheet No. 25~~
~~Environmental Surcharge~~	~~Sheet No. 29~~

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~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~Due Date~~

~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date.~~

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Tariff R.S.-L.M.-T.O.D. Continued
(Residential Service Load Management Time of Day)

Separate Metering Provision
Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be $4.30 per month.

Separate Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

The Company reserves the right to inspect at all reasonable times the energy storage and load management devices which qualify the residence for service and for conservation and load management credits under this tariff, and to ascertain by any reasonable means that the time-differentiated load characteristics of such devices meet the Company's specifications. If the Company finds, that in its sole judgment, the availability conditions of this tariff are being violated; it may discontinue billing the Customer under this tariff and commence billing under the appropriate Residential Service Tariff.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

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Tariff R.S.-T.O.D.
(Residential Service Time of Day)

Availability of Service
Available for residential electric service through a multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers, including residential customers engaged principally in agricultural pursuits. Availability is limited to the first 1,000 customers applying for service under this tariff.

Rate *(Tariff Code 036)*

Service Charge	$23~~1~~.00	per month
Energy Charge All kWh used during on-peak billing period	184.6465~~534~~¢	per kWh
All kWh used during off-peak billing period	8~~7~~.603~~888~~¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Residential Energy Assistance~~	~~Sheet No. 25~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
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~~**Due Date**~~
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Special Terms and Conditions

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This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

Continued on Sheet 5-7

Tariff R.S.-T.O.D.2
(Experimental Residential Service Time of Day 2)

Availability of Service
Available on a voluntary, experimental basis to individual residential customers for residential electric service through a multi-register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Rate *(Tariff Code 027)*

Service Charge	$23~~1~~.00	per month
Energy Charge All kWh used during Summer on-peak billing period	18.921~~849~~¢	per kWh
All kWh used during Winter on-peak billing period	13~~6~~.642~~352~~¢	per kWh
All kWh used during off-peak billing period	12~~9~~.277~~085~~¢	per kWh

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months Approximate Percent (%) of Annual Hours	**On-Peak** 16%	**Off-Peak** 84%
Winter Period: November 1 to March 31	7:00 AM to 11:00 AM 6:00 PM to 10:00 PM	11:00 AM to 6:00 PM 10:00 PM to 7:00 AM
Summer Period: May 15 to September 15	Noon to 6:00 PM	6:00 PM to Noon
All Other Calendar Periods	None	Midnight to Midnight

Note: All kWh consumed during Saturday and Sunday are billed at the off-peak level.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
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~~Fuel Adjustment Clause~~ ~~Sheet No. 5~~

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Tariff R.S.-T.O.D.2 Continued
(Experimental Residential Service Time of Day 2)

~~**Due Date**~~
~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date.~~

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

Continued on Sheet 5-9

Tariff R.S.D.
(Residential Demand-Metered Electric Service)

Availability of Service
Available for residential electric service through one single-phase multiple-register demand meter. Availability is limited to the first 1,000 customers applying for service under this tariff.

Monthly Rate *(Tariff Code 018)*

Service Charge	$23~~1~~.00	per customer
Energy Charge		
All kWh used during on-peak billing period	11~~2~~.843~~354~~¢	per kWh
All kWh used during off-peak billing period	8~~7~~.603~~888~~¢	per kWh
Demand Charge	$6~~3~~.77~~90~~	for each kW of monthly billing demand

For the purpose of this tariff, the on-peak billing period is defined as follows:

Months of October – May:	7:00 AM to 11:00 AM for all weekdays
Months of June – September	4:00 PM to 9:00 PM for all weekdays

The off-peak billing period is defined as all weekday hours not defined above as on-peak and all hours of Saturday and Sunday

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Residential Energy Assistance	Sheet No. 26
Demand-Side Management Adjustment Clause	Sheet No. 28
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Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
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~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
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Monthly Billing Demand
Customer's demand will be taken monthly to be the highest registration of a 60 minute integrating demand meter or indicator during the on- peak period.

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~~**Due Date**~~
~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date.~~

Special Terms and Conditions
This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

Tariff G.S.
(General Service)

Availability of Service
Available for general service customers. Customers may continue to qualify for service under this tariff until their average maximum demand exceeds 100 kW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

Rate

Tariff Code	Service Voltage	Demand Charge ($/kW)	First 4,450 kWh (¢/kWh)	Over 4,450 kWh (¢/kWh)	Monthly Service Charge ($)
211, 212, 215, 216, 218	Secondary	8~~6~~.82~~61~~	12~~0~~.292~~907~~	10~~0~~.813~~201~~	28~~5~~.00
217, 220	Primary	8~~6~~.03~~1~~	10~~9~~.790~~574~~	9~~8~~.533~~993~~	12~~0~~0.00
236	Subtransmission	64.38~~68~~	9~~8~~.763~~663~~	8~~8~~.629~~141~~	46~~0~~0.00

The Demand Charge shall apply to all monthly billing demand in excess of 10 kW.

Minimum Charge
This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by the monthly billing demand in excess of 10 kW.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~**Delayed Payment Charge**~~
~~This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.~~

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be

achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Continued on Sheet 6-2

Tariff G.S. Continued
(General Service)

Monthly Billing Demand

Energy supplied hereunder will be delivered through not more than one single phase and/or polyphase meter. Customer's demand will be taken monthly to be the highest registration of a 15-minute integrating demand meter or indicator, or the highest registration of a thermal type demand meter. The monthly billing demand shall be the greater of: (1) Customer's metered kW demand, (2) 60% of the Customer's contract capacity in excess of 100 kW, or (3) 60% of the customer's highest previously established monthly billing demand during the past 11 months in excess of 100 KW.

The Company reserves the right to install a demand meter on any customer receiving service under this tariff. A demand meter will be installed by the Company for customers with monthly kWh usage of 4,450 kWh or greater.

Recreational Lighting Service Provision

Available for service to customers with demands of 5 KW or greater and who own and maintain outdoor lighting facilities and associated equipment utilized at baseball diamonds, football stadiums, parks and other similar recreational areas. This service is available only during the hours between sunset and sunrise. Daytime use of energy under this rate is strictly forbidden except for the sole purpose of testing and maintaining the lighting system. All Terms and Conditions of Service applicable to Tariff G.S. customers will also apply to recreational lighting customers except for the Availability of Service.

Rate *(Tariff Code 214)*

Service Charge	$28~~5~~.00	per month
Energy Charge	13~~0~~.336~~838~~¢	per kWh

Load Management Time of Day Provision

Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

Rate *(Tariff Codes 223 and 225)*

Service Charge	$2~~5~~8.00	per month
Energy Charge		
All kWh used during on-peak billing period	18~~5~~.567~~908~~¢	per kWh
All kWh used during off-peak billing period	8~~7~~.558~~915~~¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Continued on Sheet 6-3

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff G.S. Continued
(General Service)

Optional Unmetered Service Provision
Available to customers who qualify for Tariff G.S., have a demand of less than 10 KW, and use the Company's service for commercial purposes consisting of small fixed electric loads such as traffic signals and signboards which can be served by a standard service drop from the Company's existing secondary distribution system. This service will be furnished at the option of the Company.

Each separate service delivery point shall be considered a contract location and shall be separately billed under the service contract. In the event one Customer has several accounts for like service, the Company may meter one account to determine the appropriate kilowatt-hour usage applicable for each of the accounts.

The Customer shall furnish switching equipment satisfactory to the Company. The Customer shall notify the Company in advance of every change in connected load, and the Company reserves the right to inspect the customer's equipment at any time to verify the actual load. In the event of the customer's failure to notify the Company of an increase in load, the Company reserves the right to refuse to serve the contract location thereafter under this provision, and shall be entitled to bill the customer retroactively on the basis of the increased load for the full period such load was connected or the earliest date allowed by Kentucky statute whichever is applicable.

Calculated energy use per month shall be equal to the contract capacity specified at the contract location times the number of days in the billing period times the specified hours of operation. Such calculated energy shall then be billed at the following rates:

Rate *(Tariff Codes 204 (Metered) and 213 (Unmetered))*

Customer Charge	$15.00	per month
Energy Charge		
First 4,450 kWh per month	12~~0~~.292~~907~~¢	per kWh
All Over 4,450 kWh per month	10.813~~201~~¢	per kWh

Term of Contract
Contracts under this tariff may be required of customers. Contracts under this tariff will be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company will have the right to make contracts for periods of longer than 1 (one) year.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum demand in KW which the Company might be required to furnish, but no less than 10 KW. The Company shall not be obligated to supply demands in excess of that contracted for. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point of both their power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

Continued on Sheet 6-4

DATE OF ISSUE: June 29, 2023
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ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
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Tariff S.G.S.-T.O.D.
(Small General Service Time of Day Service)

Availability of Service
Available on a voluntary, basis for general service to customers being served at secondary distribution voltage with one single-phase, multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Customers not meeting the requirements for availability under this tariff will be permitted to continue service under this tariff only for continuous service at the premises occupied on or prior to June 30, 2015.

Rate *(Tariff Code 227)*

Service Charge	$2~~5~~8.00	per month
Energy Charge		
All kWh used during Summer on-peak billing period	19~~20~~.545~~846~~¢	per kWh
All kWh used during Winter on-peak billing period	13~~8~~.784~~172~~¢	per kWh
All kWh used during off-peak billing period	12~~1~~.349~~279~~¢	per kWh

For the purpose of this tariff, the on-peak and off-peak billing periods shall be defined as follows:

Months Approximate Percent (%) of Annual Hours	**On-Peak** 16%	**Off-Peak** 84%
Winter Period: November 1 to March 31	7:00 AM to 11:00 AM 6:00 PM to 10:00 PM	11:00 AM to 6:00 PM 10:00 PM to 7:00 AM
Summer Period: May 15 to September 15	Noon to 6:00 PM	6:00 PM to Noon
All Other Calendar Periods	None	Midnight to Midnight

Note: All kWh consumed weekends are billed at the off-peak level.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

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TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
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~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

Continued on Sheet 6-5

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By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff S.G.S.-T.O.D. Continued
(Small General Service Time of Day)

~~**Delayed Payment Charge**~~
~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.~~

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

Continued on Sheet 6-6

Tariff M.G.S.-T.O.D.
(Medium General Service Time of Day)

Availability of Service
Available for general service to customers with average maximum demands greater than 10 KW but not more than 100 KW being served by a multi- register meter capable of measuring electrical energy consumption during variable pricing periods. Availability is limited to the first 500 customers applying for service under this tariff.

Rate *(Tariff Code 229)*

Service Charge	$28~~5~~.00	per month
Energy Charge		
All kWh used during on-peak billing period	18~~5~~.567~~908~~¢	per kWh
All kWh used during off-peak billing period	8~~7~~.558~~915~~¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the Service Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~**Delayed Payment Charge**~~
~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.~~

DATE OF ISSUE: June 29, 2023
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TITLE: Vice President, Regulatory & Finance
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Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Continued on Sheet 6-7

Tariff M.G.S.-T.O.D. Continued
(Medium General Service Time of Day)

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service. Existing customers may initially choose to take service under this tariff without satisfying any requirements to remain on their current tariff for at least 12 months.

Customers with PURPA Section 210 qualifying cogeneration and/or small power productions facilities shall take service under Tariff COGEN/SPP I or by special agreement with the Company.

Tariff L.G.S.
(Large General Service)

Availability of Service

Available for general service to customers with average maximum demands greater than 100 KW but not more than 1,000 KW (excluding the demand served by the Load Management Time-of-Day provision).

Existing customers not meeting the above criteria will be permitted to continue service under present conditions only for continuous service at the premises occupied on or prior to December 5, 1984.

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	240, 242, 260	244, 246, 264	248, 268	250, 270
Service Charge per Month	$97~~85~~.00	$145~~27~~.00~~50~~	$750~~660~~.00	$750~~660~~.00
Demand Charge per kW	$10~~8~~.39~~77~~	$8~~7~~.95~~0~~	$5~~6~~.39~~61~~	$5~~6~~.25~~16~~
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46
Energy Charge per kWh	8.796~~432~~¢	7.867~~356~~¢	5.975~~230~~¢	5.874~~085~~¢

Minimum Charge

Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~**Delayed Payment Charge**~~

~~This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.~~

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurements of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Continued on Sheet 7-2

Tariff L.G.S. Continued
(Large General Service)

Monthly Billing Demand
Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Determination of Excess Kilovolt-Ampere (KVA) Demand
The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

Load Management Time of Day Provision
Available to customers who use energy storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours, and who desire to receive service under this provision for their total requirements. This provision is also available for electric vehicle charging if separately metered.

Customers who desire to separately wire their load management load to a time-of-day meter and their general-use load to a standard meter shall receive service for both under the appropriate provision of this tariff.

Rate *(Tariff Code 251)*

Service Charge	$97~~85~~.00	per month
Energy Charge		
All kWh used during on-peak billing period	14.934~~426~~¢	per kWh
All kWh used during off-peak billing period	8~~7~~.695~~888~~¢	per kWh

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M. for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Term of Contract
Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Continued on Sheet 7-3

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff L.G.S. Continued
(Large General Service)

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

Continued on Sheet 7-4

Tariff L.G.S.-T.O.D.
(Large General Service Time of Day)

Availability of Service
Available for general service customers with average maximum demands of 100 KW or greater. Customers may continue to qualify for service under this tariff until their 12-month average demand exceeds 1,000 KW. Availability is limited to the first 500 customers applying for service under this tariff.

Rate

	Service Voltage			
	Secondary	**Primary**	**Subtransmission**	**Transmission**
Tariff Code	256	257	258	259
Service Charge per Month	$97~~85~~.00	$145~~27~~.0~~5~~0	$750~~660~~.00	$750~~660~~.00
Demand Charge per kW	$9~~10~~.~~92~~13	$7~~8~~.76~~17~~	$4~~1~~.40~~77~~	$4~~1~~.33~~75~~
Excess Reactive Charge per KVA	$3.46	$3.46	$3.46	$3.46
On-Peak Energy Charge per kWh	11~~0~~.793~~284~~¢	11~~0~~.238~~142~~¢	11~~0~~.075~~55~~¢	10~~9~~.938~~969~~¢
Off-Peak Energy Charge per kWh	6~~5~~.194~~360~~¢	6~~5~~.021~~318~~¢	5.970~~293~~¢	5.927~~267~~¢

For the purpose of this tariff, the on-peak billing period is defined as 7:00 A.M. to 9:00 P.M., for all weekdays Monday through Friday. The off-peak billing period is defined as 9:00 P.M. to 7:00 A.M. for all weekdays and all hours of Saturday and Sunday.

Minimum Charge
Bills computed under the above rate are subject to a monthly minimum charge comprised of the sum of the service charge and the minimum demand charge. The minimum demand charge is the product of the demand charge per KW and the monthly billing demand.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
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~~Purchase Power Adjustment~~	~~Sheet No. 35~~
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~~**Delayed Payment Charge**~~

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~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date additional charge of 5% of the unpaid portion will be made.~~

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KW values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Continued on Sheet 7-5

Tariff L.G.S.-T.O.D. Continued
(Large General Service Time of Day)

Monthly Billing Demand
Billing demand in KW shall be taken each month as the highest 15-minute integrated peak in kilowatts as registered during the month by a 15-minute integrating demand meter or indicator, or at the Company's option as the highest registration of a thermal type demand meter or indicator. The monthly billing demand so established shall in no event be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

Determination of Excess Kilovolt-Ampere (KVA) Demand
The maximum KVA demand shall be determined by the use of a multiplier equal to the reciprocal of the average power factor recorded during the billing month, leading or lagging, applied to the metered demand. The excess KVA demand, if any, shall be the amount by which the maximum KVA demand established during the billing period exceeds 115% of the kilowatts of metered demand.

Term of Contract
Contracts under this tariff will be made for customers requiring a average maximum monthly demand between 500 KW and 1,000 KW and be made for an initial period of not less than l (one) year and shall remain in effect thereafter until either party shall give at least 6 months written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts or periods greater than 1 (one) year. For customers with demands less than 500 KW, a contract may, at the Company's option, be required.

Where new Company facilities are required, the Company reserves the right to require initial contracts for periods greater than one year for all customers served under this tariff.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for (the "contract capacity") in an amount up to 1,000 KW. Contracts will be made in multiples of 25 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to Customers having other sources of energy supply but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the customer shall contract for the maximum amount of demand in KW, which the Company might be required to furnish, but not less than 100 KW nor more than 1,000 KW. The Company shall not be obligated to supply demands in excess of the contract capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billings periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

This tariff is available for resale service to mining and industrial customers who furnish service to customer-owned camps or villages where living quarters are rented to employees and where the customer purchases power at a single point for both his power and camp requirements.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP I or II or by special agreement with the Company.

Tariff I.G.S.
(Industrial General Service)

Availability of Service
Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet average maximum requirements.

Rate

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	356	358/370	359/371	360/372
Service Charge per Month	$276.00	$276.00	$794.00	$1,353.00
Demand Charge per kW				
Of monthly on-peak billing demand	$27~~5~~.32~~88~~	$25~~2~~.31~~96~~	$1~~6~~7.89~~33~~	$17~~6~~.52~~08~~
Of monthly off-peak billing demand	$1.84~~0~~	$1.78	$1.75~~6~~	$1.73~~5~~
Energy Charge per kWh	3~~2~~.214~~698~~¢	3~~2~~.063~~660~~¢	3~~2~~.018~~635~~¢	2.981~~612~~¢

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand………………………………….. $0.69/KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

Minimum Demand Charge
The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission
$26~~8~~.01~~77~~ / kW	$24~~5~~.05~~81~~ / kW	$11~~1~~6~~9~~.64~~17~~ / kW	$16~~8~~.29~~88~~ / kW

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

Minimum Charge
This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~

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~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~Delayed Payment Charge~~

~~Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.~~

Continued on Sheet 8-2

Tariff I.G.S. Continued
(Industrial General Service)

Metered Voltage
The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

1. Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
2. Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Monthly Billing Demand
The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

Term of Contract
Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

Contract Capacity
The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiplies of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

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Tariff M.W.
(Municipal Waterworks)

Availability of Service
Available only to incorporated cities and towns and authorized water districts and to utility companies operating under the jurisdiction of Public Service Commission of Kentucky for the supply of electric energy to waterworks systems and sewage disposal systems served under this tariff on September 1, 1982, and only for continuous service at the premises occupied by the Customer on this date. If service hereunder is discontinued, it shall not again be available.

Customer shall contract with the Company for a reservation in capacity in kilovolt-amperes sufficient to meet with the maximum load, which the Company may be required to furnish.

Rate *(Tariff Code 540)*

Service Charge	$28~~5~~.00	per month
Energy Charge All kWh used per month	10~~9~~.506~~800~~¢	per kWh

Minimum Charge
This tariff is subject to a minimum monthly charge equal to the sum of the service charge plus $9.55~~78~~ per KVA as determined from customer's total connected load.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~**Payment**~~
~~Bills will be rendered monthly and will be due and payable on or before the due date stated on the bill.~~

~~**Delayed Payment Charge**~~

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~~Bills under this tariff are due and payable within fifteen (15) days after their mailing date. All accounts not paid in full by the next billing date will be assessed an additional charge of 5% of the outstanding unpaid portion will be made.~~

Term of Contract
Contracts under this tariff will be made for not less than (1) one year with self-renewal provisions for successive periods of (1) one year each until either party shall give at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period. The Company will have the right to require contracts for periods of longer than (1) one year.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is not available to customers having other sources of energy supply.

Tariff O.L.
(Outdoor Lighting)

Availability of Service
Available for outdoor lighting to individual customers in locations where municipal street lighting is not applicable provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium, Mercury Vapor and Metal Halide lamps shall cease on January 14, 2021.

Base Fuel Rate
Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

Rate

A. Overhead Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	094	100 (9,500 Lumens)	$10~~9~~.53~~06~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	113	150 (16,000 Lumens)	$12~~0~~.01~~33~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	097	200 (22,000 Lumens)	$14~~2~~.55~~2~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	103	250 (28,000 Lumens)	$20~~17~~.74~~84~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	098	400 (50,000 Lumens)	$22~~19~~.99~~78~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~

	Tariff Code	Watts	Rate	
Mercury Vapor	093	175 (7,000 Lumens)	$13~~1~~.43~~55~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	095	400 (20,000 Lumens)	$23~~19~~.11~~88~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~

	Tariff Code	Lumens	Rate	
LED	150	6,000-10,000~~8,500~~	$7~~6~~.70~~62~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. Post-Top Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	111	100 (9,500 Lumens)	$1~~6~~9.09~~42~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	122	150 (16,000 Lumens)	$30~~25~~.0~~8~~3	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	~~121~~	~~100 (9,500 Lumens)~~	~~$30.00~~	~~per lamp + 0.02612 x kWh in Sheet No. 14-5 in Company's tariff~~
	120	250 (19,000 Lumens)	$34~~0~~.96~~07~~	per lamp + 0.02612 x kWh in Sheet No. 10-4~~14-5~~ ~~in Company's tariff~~

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	126	400 (40,000 Lumens)	$45~~39~~.88~~47~~	per lamp + 0.02612 x kWh in Sheet No. 10-4~~14-5~~ ~~in Company's tariff~~

	Tariff Code	Watts	Rate	
Mercury Vapor	099	175 (7,000 Lumens)	$1~~3~~5.40~~25~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~

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Tariff O.L. Continued
(Outdoor Lighting)

Post-Top Lighting Service Continued

	Tariff Code	Lumens	Rate	
LED	160	6,000~~4,300~~- 10,000~~6,300~~	$22~~19~~.1~~0~~5	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-40~~5~~ ~~in Company's tariff~~

Company will provide lamp photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits. Incremental costs of installation beyond thirty feet shall be the responsibility of the customer.

C. Flood Lighting Service

	Tariff Code	Watts	Rate	
High Pressure Sodium	107	200 (22,000 Lumens)	$16~~4~~.72~~38~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	109	400 (50,000 Lumens)	$24~~1~~.41~~00~~	per lamp + 0.02612 x kWh in Sheet No. 1~~4~~0-4~~5~~ ~~in Company's tariff~~

	Tariff Code	Watts	Rate	
Metal Halide	110	250 (20,500 Lumens)	$20~~17~~.29~~45~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	116	400 (36,000 Lumens)	$25~~1~~.55~~98~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	131	1,000 (110,000 Lumens)	$46~~0~~.5~~0~~1	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	130	250 Mongoose (20,500 Lumens)	$26~~2~~.4~~7~~6	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	136	400 Mongoose (36,000 Lumens)	$32~~27~~.29~~78~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~

	Tariff Code	Lumens	Rate	
LED	165	17~~9~~,500-22~~1~~,500	$28~~4~~.77~~5~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~
	166	42~~36~~,500-47~~38~~,500	$35~~0~~.34~~40~~	per lamp + 0.02612 x kWh in Sheet No. 10~~4~~-4~~5~~ ~~in Company's tariff~~

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

D. LED Lamp Conversion Charge
Existing outdoor lighting customers that wish to convert from non-LED lamps to new LED fixtures shall pay a monthly charge of $3.33 per lamp replaced, per month for 84 months.

All lumen figures are based upon manufacturer estimates and may vary.

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

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Wood Pole	$4~~3~~.20~~61~~	per month
Overhead wire span not over 150 feet	$2.33~~00~~	per month
Underground wire lateral not over 50 feet	$7~~6~~.8~~7~~7	per month

(Price includes pole riser and connections)

Continued on Sheet 10-3

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Tariff O.L. Continued
(Outdoor Lighting)

E. Flexible Lighting Option *(Tariff Code 175 for Unmetered and Tariff Code 201 for Metered)*
Applicable for the installation of any outdoor area lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use if it is not metered. The Company reserves the right to refuse service under this provision based on customer's creditworthiness.

Rate
Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of 1.43~~36~~% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

Monthly maintenance charge is $0.80 per lamp per month
Monthly non-fuel charge is .08698~~5519~~ $/kWh
Base fuel charge is 0.02612 $/kWh

Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
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For adjustments calculated on a per kWh basis~~, including those calculated under the Fuel Adjustment Clause, System Sales Clause, and the Capacity Charge tariffs,~~ the following kWh values will be used in the calculation:

Continued on Sheet 10-4

Tariff O.L. Continued
(Outdoor Lighting)

	Metal Halide			Mercury Vapor		High Pressure Sodium				
	250 Watts	400 Watts	1,000 Watts	175 Watts	400 Watts	100 Watts	150 Watts	200 Watts	250 Watts	400 Watts
Jan	127	199	477	91	199	51	74	106	130	210
Feb	106	167	400	76	167	43	62	89	109	176
Mar	106	167	400	76	167	43	62	89	109	176
Apr	90	142	340	65	142	36	53	76	93	150
May	81	127	304	58	127	32	47	68	83	134
Jun	72	114	272	52	114	29	42	61	74	120
Jul	77	121	291	55	121	31	45	65	79	128
Aug	88	138	331	63	138	35	51	74	90	146
Sep	96	152	363	69	152	39	57	81	99	160
Oct	113	178	427	81	178	45	66	95	116	188
Nov	119	188	449	86	188	48	70	100	122	198
Dec	129	203	486	92	203	52	75	108	132	214
Total	1,204	1,896	4,540	864	1,896	484	704	1,012	1,236	2,000

	Light Emitting Diode (LED)			
	150 Tariff Code 6,000-10,000~~8,500~~ Lumens	160 Tariff Code ~~4,300-6,300~~6,000-10,000 Lumens	165 Tariff Code 17~~9~~,500-22~~1~~,500 Lumens	166 Tariff Code 42~~36~~,500-47~~38~~,500 Lumens
Jan	28	33	75	154
Feb	24	28	63	129
Mar	24	28	63	129
Apr	20	24	53	109
May	18	21	48	96
Jun	16	19	43	87
Jul	17	20	46	93
Aug	19	23	52	105
Sep	22	26	58	118
Oct	25	30	67	136
Nov	27	32	71	145
Dec	29	33	77	156
Total	269	317	716	1,457

Continued on Sheet 10-5

Tariff O.L. Continued
(Outdoor Lighting)

~~**Delayed Payment Charge**~~
~~This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made. Residential customers taking service under this tariff will not be subject to the delayed payment charge.~~

Hours of Lighting
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

Ownership of Facilities
All facilities necessary for service including fixtures, controls, poles, transformers, secondaries, lamps and other appurtenances shall be owned and maintained by the Company. All service and necessary maintenance will be performed only during the regular scheduled working hours of the Company.

The Company shall be allowed 3 working days after notification by the customer to replace all burned-out lamps.

Term of Initial Service
Term of initial service shall be required for a period of one year. If early termination is requested or service is terminated during the initial 12 month period, the customer will be billed for the remainder of the 12 month period on the final bill.

Special Terms and Conditions
This tariff is subject to the Company’s Terms and Conditions of Service.

The Company shall have the option of rendering monthly or bimonthly bills.

Customer’s account balance must be current prior to installation of new or additional lights.

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Tariff S.L.
(Street Lighting)

Availability of Service
Available for lighting service for all the lighting of public streets, public highways and other public outdoor areas in municipalities, counties, and other governmental subdivisions where such service can be supplied from the existing general distribution systems provided the lighting location designated by the Customer is reasonably accessible to the Company's service vehicles without causing damage to the Customer's or other's property. New installations of High Pressure Sodium lamps shall cease on January 14, 2021.

Base Fuel Rate
Customers receiving service under this tariff will receive bills calculated using per lamp and base fuel charge. The base fuel charge will be calculated each month as shown below by multiplying the approved base fuel amount set forth in the Company's Fuel Adjustment Clause tariff by the relevant monthly kWh value set forth in the monthly kWh table included below in the Adjustment Clauses section of this tariff.

Rate *(Tariff Code 528)*

A. Overhead Service on Existing Distribution Poles

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$8~~7~~.49~~61~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	150 (16,000 Lumens)	$9~~8~~.32~~6~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	200 (22,000 Lumens)	$11~~9~~.04~~90~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	400 (50,000 Lumens)	$1~~3~~4.50~~00~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~

	Lumens	Rate	
LED	~~7,900-9,900~~8,000-11,000	$9.71~~8.71~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	~~10,500-12,500~~10,000-14,000	$12.48~~11.19~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	24,000-~~26,000~~30,000	$14.87~~13.34~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	Post Top ~~4,300-6,300~~6,000-10,000	$10.09~~9.05~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	Post Top ~~7,300-9,300~~8,000-12,000	$22.38~~20.07~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	Flood 17~~9~~,500-22~~1~~,500	$16.38~~14.69~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~

B. Service on New Wood Distribution Poles

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$13~~1~~.27~~90~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	150 (16,000 Lumens)	$14~~2~~.22~~75~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	200 (22,000 Lumens)	$15~~4~~.94~~30~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~
	400 (50,000 Lumens)	$20~~18~~.46~~35~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4~~ ~~in Company's tariff~~

	Lumens	**Rate**	
LED	~~7,900-9,900~~8,000-11,000	$16.01~~14.36~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4 in Company's tariff~~
	~~10,500-12,500~~10,000-14,000	$18.79~~16.85~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4 in Company's tariff~~
	24,000-~~26,000~~30,000	$21.19~~19.00~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4 in Company's tariff~~
	Post Top 6,000-10,000~~4,300-6,300~~	$16.39~~14.70~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4 in Company's tariff~~
	Post Top 8,000-12,000~~7,300-9,300~~	$28.69~~25.73~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4 in Company's tariff~~
	Flood 17~~9~~,500-22~~1~~,500	$22.69~~20.35~~	per lamp + 0.02612 x kWh in Sheet No. 11-3~~5-4 in Company's tariff~~

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Tariff S.L. Continued
(Street Lighting)

C. Service on New Metal or Concrete Poles*

	Watts	Rate	
High Pressure Sodium	100 (9,500 Lumens)	$27~~4~~.65~~80~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	150 (16,000 Lumens)	$28~~5~~.66~~70~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	200 (22,000 Lumens)	$30~~27~~.38~~25~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	400 (50,000 Lumens)	$33~~0~~.84~~35~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~

	Lumens	Rate	
LED	~~7,900-9,900~~8,000-11,000	$27.99~~25.10~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	~~10,500-12,500~~10,000-14,000	$29.86~~26.78~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	24,000-~~26,000~~30,000	$31.34~~28.11~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	Post Top ~~4,300-6,300~~6,000-10,000	$28.82~~25.85~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	Post Top ~~7,300-9,300~~8,000-12,000	$40.97~~36.74~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~
	Flood 1~~9~~7,500-2~~1~~2,500	$32.80~~29.42~~	per lamp + 0.02612 x kWh in Sheet No. 11-35~~-4~~ ~~in Company's tariff~~

* Effective June 29, 2010 and thereafter these lamps are not available for new installations

D. LED Lamp Conversion Charge

Existing street lighting customers that wish to convert from non-LED lamps to a new LED fixture shall pay a monthly charge of $2.18 per lamp replaced, per month for 84 months.

All lumen figures are based upon manufacturer estimates and may vary.

E. Flexible Lighting Option *(Tariff Code 525 for Unmetered and Tariff Code 526 for Metered)*

Applicable for the installation of any street lighting system (System) on a private or public property and owned by the Company. The customer must be adjacent to an electric power line of the Company that is adequate for supplying the necessary electric service. Service for the System under this tariff shall require a contract addendum agreed to and signed by the customer. The System shall comply with the Company's terms and conditions unless otherwise noted in this section. Included in the contract addendum shall be the installed capital cost of the System and the monthly amount of kWh the System will use unless the system is separately metered. The Company reserves the right to refuse service under this provision based on customer's credit worthiness.

Rate

Customers shall pay the monthly lamp charge for the System, a monthly maintenance charge, a non-fuel energy charge, a base fuel charge, and all applicable adjustment clauses.

Monthly Lamp Charge* = IC x MLFCR

Where:
IC = Installed Cost of System
MLFCR = Monthly Levelized Fixed Cost Rate of 1.04~~0.97~~% which is inclusive of return, depreciation, income taxes, property taxes and A&G expense components

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Monthly maintenance charge is $2.52 per lamp per month
Monthly non-fuel charge is .052614~~393~~ $/kWh
Base fuel charge is 0.02612 $/kWh

Customers selecting this flexible lighting option to replace existing lamps shall also be subject to the LED Lamp Conversion Charge.

*Customers may pay a portion of the installed cost upfront to reduce the monthly lamp charge component of the rate.

Continued on Sheet 11-3

Tariff S.L. Continued
(Street Lighting)

Adjustment Clauses

The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

For adjustments calculated on a per kWh basis~~, including those calculated under the Fuel Adjustment Clause, System Sales Clause, and the Capacity Charge tariffs,~~ the following kWh values will be used in the calculation:

	High Pressure Sodium				Light Emitting Diode (LED)					
	100 Watts	150 Watts	200 Watts	400 Watts	~~7,900-9,900~~8,000-11,000 Lumens	~~10,500-12,500~~10,000-14,000 Lumens	24,000-~~26,000~~30,000 Lumens	Post Top ~~4,300-6,300~~6,000-10,000 Lumens	Post Top ~~7,300-9,300~~8,000-12,000 Lumens	Flood 17~~9~~,500-22~~1~~,500 Lumens
Jan	51	74	106	210	35	49	98	33	48	75
Feb	43	62	89	176	30	40	83	28	41	63
Mar	43	62	89	176	30	40	83	28	41	63
Apr	36	53	76	150	25	34	70	24	34	53
May	32	47	68	134	22	30	62	21	31	48
Jun	29	42	61	120	20	27	56	19	27	43
Jul	31	45	65	128	21	29	60	20	29	46
Aug	35	51	74	146	23	33	68	23	32	52
Sep	39	57	81	160	27	37	75	26	37	58
Oct	45	66	95	188	31	43	87	30	43	67
Nov	48	70	100	198	33	46	93	32	45	71
Dec	52	75	108	214	36	50	100	33	50	77
Total	484	704	1,012	2,000	333	458	935	317	458	716

Special Facilities

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When a customer requests street lighting service which requires special poles or fixtures, underground street lighting, or a line extension of more than one span of approximately 150 feet, the customer will be required to pay, in advance, an aid-to-construction in the amount of the installed cost of such special facilities.

~~**Payment**~~
~~Bills are due and payable within ten (10) days of the mailing date.~~

Continued on Sheet 11-4

Tariff S.L. Continued
(Street Lighting)

Hours of Lighting
All lamps shall burn from one-half hour after sunset until one-half hour before sunrise every night and all night, burning approximately 4,000 hours per annum.

Term of Contract
Contracts under this tariff will ordinarily be made for an initial term of one year with self-renewal provisions for successive periods of one year each until either party shall give at least 60 days' notice to the other of the intention to discontinue at the end of the initial term or any yearly period. The Company may have the right to require contracts for periods of longer than one year if new or additional facilities are required.

Special Terms and Conditions
A customer's account balances must be current prior to installation of new or additional lights.

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Tariff P.A.
(Pole Attachments)

1. Availability of Service

Available to broadband internet providers, cable television system operators, governmental units and telecommunications carriers that provide service within the operating area of Kentucky Power Company (Company). This Tariff is not available to: (1) the Attachments of utilities, including local exchange carriers (LECs), that have joint use agreements with Company; or (2) macro cell facilities. Nothing in this Tariff expands the right to attach to Company's facilities beyond the rights otherwise conveyed by law.

2. Definitions

Unless stated otherwise, the terms used in this Tariff shall have the same meaning as the terms expressly defined in Section 1 of 807 KAR 5:015.

"Approved Contractor" means a contractor approved by Company for a particular purpose.

"Attachment" means a Wireline Facility or Wireless Facility and all associated equipment, including without limitation, any overlashed cable or fiber, guying, small splice panels and vertical overhead to underground risers but shall not include power supplies, equipment cabinets, meter bases or other equipment that impedes accessibility or otherwise conflicts with Company's standards. For billing purposes, the term "Attachment" also includes: (1) a Service Drop affixed to a pole that is located more than one (1) vertical foot away from the point at which the messenger strand is attached to the pole; and (2) a Service Drop located on a dedicated service, drop or lift pole.

"Communications Space" means the area on a pole below the Communications Worker Safety Zone and above the point on the pole necessary to meet NESC clearance, department of transportation or other governmental requirements, and Company's construction standards.

"Facility" means any Company Distribution Pole, right-of-way, conduit or duct normally used by Company to support or protect its electric conductors. The term "Facility" does not include any Transmission Pole.

"Distribution Pole" means a utility pole supporting electric supply facilities, all of which operate at less than 69kV, but does not include a pole used primarily to support outdoor lighting.

"NESC" means the National Electrical Safety Code.

"Larger Order" means an application, or multiple applications submitted within thirty (30) days of one another, seeking to make Attachments to more than three hundred (300) poles.

"Operator" means a broadband internet provider, cable television system operator, governmental unit or telecommunications carrier.

"Overlashing" means the practice whereby an entity, whether Operator or a third party, physically connects or attaches, through lashing or otherwise, new fiber optic or coaxial cable, or any other type of cable, to an existing Wireline Attachment on a Distribution Pole.

"Service Drop" means a Wireline Facility, attached to a pole with a J-hook or other similar hardware, that connects the trunk line to an end user's premises, and extends directly from the trunk line to a drop/lift pole or into an end user's premises.

"Transmission Pole" means any utility pole or tower supporting electric supply facilities designed to operate at 69kV or greater.

"Wireline Facility" means fiber optic or coaxial cable, or any other type of cable, as well as any messenger wire or support strand.

Continued on Sheet 12-2

Tariff P.A. Continued
(Pole Attachments)

"Wireless Facility" means, without limitation, antennas, risers, transmitters, receivers, and all other associated equipment used in connection with Operator's provision of wireless communications services and the transmission and reception of radiofrequency signals, but shall not include power supplies, equipment cabinets, meter bases, and other equipment that impedes accessibility or that conflicts with Company's standards. The term "Wireless Facility" does not include any strand-mounted antennas or macro cell facilities.

3. Rate

Charge for Wireline Facility on a two-user pole	$10.82	per attachment per year
Charge for Wireline Facility on a three-user pole	$6.71	per attachment per year

The above rate was calculated in accordance with the following formula:

Weighted Average Bare Pole Cost x Usage Factor x Carrying Charge = Rate Per Pole

A two-user pole is a pole being used, by actual occupation or reservation, by the Operator and the Company. A three-user pole is a pole being used by actual occupation or reservation, by the Operator, the Company, and a third party.

Charge for Attachments within ducts or conduits	$2.70	per linear foot per year
Charge for attachment of Wireless Facility to top of Distribution Pole	$150	per attachment per year
Charge for attachment of Wireless Facility within Communications Space of Distribution Pole	$75	per attachment per year

The above rates are subject to revision from time to time as approved by the Commission.

4. Company Facilities Subject to Attachment
Pursuant to 807 KAR 5:015 and the terms and conditions of this Tariff, Attachments to Company Facilities that do not interfere with Company's electric service requirements shall be permitted. Company may deny access to any Company Facility on a non-discriminatory basis where there is insufficient capacity or for reasons of safety, reliability, and generally applicable engineering purposes.

All Company Facilities covered by this Tariff remain the property of Company regardless of any payment by Operator toward their cost. No use, however extended, of Company Facilities or payment of any fee or charge required hereunder shall create or vest in Operator any claim or right, possession, title, interest or ownership in such Facilities. Nothing in this Tariff shall be construed to obligate Company to construct, reconstruct, retain, extend, repair, place, replace or maintain any Facility which, in Company's sole discretion, is not needed for Company's own purposes. Company and its successors and assigns shall have the right to operate, relocate and maintain Company Facilities in such a manner as will best enable Company, in its sole discretion, to fulfill its service requirements.

5. Company's Pole Attachment Policy Handbook
Operator is expected to follow the processes and guidelines set forth in Company's Pole Attachment Policy handbook, as well as any amendments thereto, but only to the extent that such processes and guidelines do not conflict with 807 KAR 5:015 or this Tariff.

Continued on Sheet 12-3

Tariff P.A. Continued
(Pole Attachments)

6. Applications

When Operator proposes to furnish service within Company's operating area and desires to make Attachments to Company Facilities, Operator shall make written application to install such Attachments, in the format required by Company, that specifies the location of each Facility in question, the character of its proposed Attachments, and any other information necessary to calculate the transverse and vertical load placed upon the pole as a result of the proposed Attachment and any other attachments or equipment attached to the Facility. If Operator's application qualifies as a Larger Order, Operator shall provide Company at least sixty (60) days' advance written notice before submission to Company. Company will notify Operator, within ten (10) days of receipt of an application, if the application is incomplete. If the application is incomplete, Operator shall provide the additional information required by Company prior to Company's review of the application on its merits.

If Operator is only seeking to make Wireline Attachments to Distribution Poles, Company shall complete a make-ready survey within forty-five (45) days (or within sixty (60) days in the case of a Larger Order) of receipt of a complete application. Company may, in its sole discretion, require prepayment for a make-ready survey. The current per pole estimate for a make-ready survey is $275. If the actual cost of performing the make-ready survey exceeds the amount of Operator's prepayment, then Operator shall reimburse Company for any difference upon receipt of an invoice for such amount. If the actual cost of performing the make-ready survey is less than the amount of Operator's prepayment, then Company shall issue Operator a refund for the difference. Company shall use commercially reasonable efforts to provide at least five (5) days advance notice of a field inspection to Operator and any other affected third party. If Operator submits a make-ready survey with an application, Company may elect to utilize the survey by: (1) notifying the affected third parties of its intent to use the make-ready survey performed by Operator; and (2) providing the affected third parties with a copy of the make-ready survey within the deadline set forth above for completing a make-ready survey.

Within forty-five (45) days (or within sixty (60) days in the case of Larger Orders) after receipt of a complete application, Company shall notify Operator whether and to what extent any special conditions will be required to permit the use by Operator of each such pole. Within fourteen (14) days of providing such notice, Company shall provide Operator with a statement of the costs for any necessary Company make-ready work, including the cost of rearranging Company's electric supply facilities or pole changeouts. Operator shall indicate its approval of the make-ready cost statement by submitting payment to Company within fourteen (14) days of receipt of the make-ready cost statement. If payment is not received by Company within fourteen (14) days, then Company's make-ready cost statement shall be deemed withdrawn. Within seven (7) days of receipt of Operator's payment, Company shall notify, in a manner consistent with applicable law, all third parties whose attachments might be affected by the make-ready, and thereafter provide Operator with the contact information for, and copies of the notices sent to, such third parties. Thereafter, Operator shall be responsible for coordinating the rearrangement or transfer of any third-party attachment and shall pay the costs related thereto.

Operator shall reimburse Company for any expenses incurred in reviewing Operator's written applications for attachment. Operator shall have a non-exclusive right to use such Facilities of Company as may be used or reserved for use by Operator and any other Facilities of Company when brought hereunder in accordance with the procedure hereinafter provided. Company shall have the right to grant to others, by contract or otherwise, rights or privileges to use any Facilities of Company and Company shall have the right to continue and extend any such rights or privileges heretofore granted.

Continued on Sheet 12-4

Tariff P.A. Continued
(Pole Attachments)

7. Standards for Installation
All Attachments and associated equipment of Operator shall be installed in a manner satisfactory to Company and so as not to interfere with the present or any future use which Company may desire to make of the Facilities covered by this Tariff. All such Attachments and equipment shall be installed and at all times maintained by Operator so as to comply with the standards set forth in Company's Pole Attachment Policy handbook, the National Electrical Safety Code and any other applicable regulations or codes promulgated by state, local or other governmental authority having jurisdiction thereover. In the event of a conflict, the more stringent standard shall apply. Operator shall take necessary precautions by the installation of protective equipment or other means, to protect all persons and property of all kinds against injury or damage occurring by reason of Operator's attachments.

Operator shall complete the installation of its Attachments within thirty (30) days of Company's approval of the application for such Attachments, or if make-ready is required to accommodate the Attachments, the completion date of such make-ready. Operator shall, within seven (7) days after completing the installation of its Attachments, provide Company with written notice of such completion, and Company shall have the right to perform a post-inspection on such Attachments, at Operator's sole expense, within ninety (90) days of receipt of Operator's notice of completion. If Company's inspection reveals that Operator's installation resulted in any property damage or code violations, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

8. Tagging Requirement
Operator shall identify each of its Attachments with a tag, approved in advance by Company, that includes Operator's name, 24-hour contact telephone number, and such other information as Company may require. Operator shall tag an Attachment at the time of construction. Any untagged Attachment existing as December 28, 2022 shall be tagged by Operator by no later than December 31, 2024.

9. Overlashing
Operator shall provide Company with at least thirty (30) days' advance written notice before Overlashing, or allowing a third party to overlash, Operator's existing Wireline Facilities. Operator is responsible for all Overlashing performed on its Wireline Facilities, including any Overlashing by a third party, and shall ensure that all Overlashing complies with Company's standards, the applicable provisions of the NESC, and any other applicable law or code. If Overlashing of Operator's Wireline Facilities results in any damage to the pole, Company equipment or existing Attachments, or if any Overlashing causes a safety or engineering standard violation, Operator shall be responsible, at its expense, for any necessary repairs or corrections.

Operator shall notify Company within fifteen (15) days of completion of an overlash on a particular pole. Within ninety (90) days of receiving such notice, Company will perform an inspection at Operator's expense to determine whether the overlash caused any damage to Company property or resulted in any code violations. Company shall notify Operator of any damage to Company property or code violations within fourteen (14) days after completion of the inspection. At Company's discretion, Company may either: (1) complete any necessary remedial work and bill Operator for the costs related to fixing the damage or correcting the code violations; or (2) require Operator to fix the damage or code violations at its own expense within fourteen (14) days' notice from Company.

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Tariff P.A. Continued
(Pole Attachments)

10. Pole Installation or Replacement; Rearrangements; Guying

In any case Operator proposes to install Attachments on a pole to be erected by Company in a new location, and to provide adequate space or strength to accommodate such Attachments such pole must, in Company's judgment, be taller and/or stronger than would be necessary to accommodate the facilities of Company and of other persons who have previously indicated that they desire to make attachments on such pole or with whom Company has an agreement providing for joint or shared ownership of poles, the cost of such extra height and/or strength shall be paid to Company by Operator. Such cost shall be the difference between the cost in place of the new pole and the current cost in place of a pole considered by Company to be adequate for the facilities of Company and the attachments of such other persons.

Where in Company's judgment a new pole must be erected to replace an existing pole solely to adequately provide for Operator's proposed Attachments, Operator agrees to pay Company for the entire cost of the new pole necessary to accommodate the existing facilities on the pole and Operator's proposed Attachments, plus the cost of removal of the in-place pole, minus the salvage value, if any, of the removed pole. Operator shall also pay to Company and to any other owner of existing attachments on the pole the cost of transferring each of their respective facilities or attachments to the newly-installed pole.

If Operator's desired Attachments can be accommodated on existing poles of Company by rearranging facilities of Company thereon or of any other person, or if because of Operator's proposed Attachments it is necessary for Company to rearrange its facilities on any pole not owned by it, then in any such case, Operator shall reimburse Company and any such other person for the respective expense incurred in making such rearrangement.

If because of the requirements of its business, Company intends to replace an existing pole on which Operator has any Attachment, or Company intends to change the arrangements of its facilities on any such pole in such manner as to necessitate a rearrangement of Operator's Attachment, or if as a result of any inspection of Operator's Attachments Company determines that any such Attachments are not in accordance with Company's standards, applicable codes or the provisions of this Tariff or are otherwise hazards Company shall give Operator not less than sixty (60) days' notice of such proposed replacement or change, or any such violation or hazard; provided, however, that the sixty (60) day notice requirement shall not apply to: (1) make-ready notices pursuant to Section 4 of 807 KAR 5:015; (2) routine maintenance by Company; or (3) a replacement or change made by Company in response to an emergency. In such event, Operator shall at its expense relocate, rearrange or modify its Attachments at the time specified by Company. If Operator fails to do so, or if any such emergency makes notice impractical, Company shall perform such relocation or rearrangement and Operator shall reimburse Company for the reasonable cost thereof.

Any additional guying or anchors required by reason of the Attachments of Operator shall be provided at the expense of Operator and shall meet the requirements of all applicable codes or regulations and Company's generally applicable guying standards.

11. Self-Help Remedy

If Company is unable to meet the timelines in 807 KAR 5:015 for completing a survey or completing make-ready work above the Communications Space, and if Company lacks good and sufficient cause to deviate from such timelines, Operator may perform such work at its own expense using an Approved Contractor. Operator shall refer to Company's Pole Attachment Policy on Company's website for a list of Approved Contractors for specified purposes. Self-help is not available for pole replacements or for surveys or make-ready related to ducts. Operator shall provide written notice to Company at least one (1) week prior to performing surveys or make-ready above the Communications Space. Operator shall notify Company immediately if a survey or make-ready causes any property damage or an outage that is reasonably likely to interrupt Company's services.

Continued on Sheet 12-6

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Tariff P.A. Continued
(Pole Attachments)

12. One-Touch Make-Ready

For Attachments to Distribution Poles that require only "simple make-ready," as that term is defined in 807 KAR 5:015, Operator may elect to proceed with the one-touch make-ready (OTMR) process established in this Section 12, as opposed to the standard process set forth in Section 6 of this Tariff. To elect OTMR, Operator must clearly indicate in its application that it is electing the OTMR process. Operator shall not combine requests for "simple make-ready" and "complex make-ready," as those terms are defined in 807 KAR 5:015, within an OTMR application. Operator's OTMR application shall identify the "simple make-ready" that it intends to perform.

Company shall, within ten (10) days of receipt, determine whether Operator's OTMR application is complete. Upon receipt of a complete OTMR application, Company shall review such application on the merits within the timelines established by 807 KAR 5:015. If Company denies an OTMR application on the merits, Company will provide Operator with an explanation of its denial, along with information and documentation supporting Company's decision.

Operator shall be responsible for all surveys required as part of the OTMR process. Any survey performed under the OTMR process shall be conducted by an Approved Contractor. Operator shall provide Company, as well as any third parties with attachments on Distribution Poles subject to an OTMR application, at least five (5) days' advance written notice of any field inspection, and such notice shall: provide the date, time and location of the field inspection; and state the name of the Approved Contractor that will be performing the field inspection. Operator shall allow Company and affected third parties to be present for any field inspection it performs under the OTMR process.

If Operator's OTMR application is approved, Operator may, after providing fifteen (15) days' advance written notice to Company and affected third parties, proceed with the make-ready. Operator's notice shall: provide the date, time and location of the make-ready; describe the make-ready involved; and identify the contractor that will be performing the make-ready. Operator shall allow Company and affected third parties to be present during the make-ready. Operator shall complete all make-ready within thirty (30) days of the date on which Company approved Operator's OTMR application (or within seventy-five (75) days in the case of a Larger Order), or Operator's OTMR application will be deemed closed.

If Company or Operator determine at any time that make-ready does not qualify as "simple make-ready," Operator shall halt all make-ready on the impacted Distribution Poles. The make-ready on the impacted Distribution Poles shall thereafter be subject to the requirements of Section 6 of this Tariff. Operator shall notify Company and affected third parties within fifteen (15) days of completion of the make-ready identified in the OTMR application.

13. Pole Inspection

Company may make periodic inspections, as conditions may warrant, for the purpose of determining compliance with the provisions of this Tariff. Company reserves the right to inspect each new or proposed installation of Operator on Company's Facilities. In addition, Company's right to make any inspections and any inspection made pursuant to such right shall not relieve Operator of any responsibility, obligation or liability assumed under this Tariff.

14. Transfer of Attachments to New Poles

Operator shall transfer its Attachments within sixty (60) days of receiving notice from Company (Transfer Period). If Operator fails to transfer its Attachments within the Transfer Period, Company may transfer the Attachments at Operator's sole risk and expense. Company may transfer Operator's Attachments prior to the expiration of the Transfer Period if an expedited transfer is necessary for safety or reliability purposes.

Continued on Sheet 12-7

Tariff P.A. Continued
(Pole Attachments)

15. Attachment Inventory
Owner may conduct a complete field inventory for the purpose of verifying the number and location of Operator's Attachments on Company Facilities. Company shall provide Operator with at least thirty (30) days' prior notice of a field inventory, and Operator shall advise Company whether Operator desires to participate in the field inventory not less than fifteen (15) days prior to the scheduled date of such inventory. Operator shall reimburse Company for the costs Company incurs in performing the field inventory, regardless of whether Operator elects to participate in the inventory; provided, however, Company may not charge Operator for more than one (1) field inventory within a five (5) year period. If Company inspects the Attachments of more than one Operator during a field inventory, then each Operator whose Attachments were inspected by Company during the field inventory shall share pro rata in the costs of such inventory. Upon request, Company shall furnish a summary report for the field inventory within a reasonable time after its completion.

If a field inventory reveals that the number of Operator's Attachments exceeds the number of Attachments shown in Company's existing records, the excess number of Attachments shall be presumed to be unauthorized attachments and handled in accordance with Section 16.

16. Unauthorized Attachments
If Operator makes an Attachment that requires approval by, or advance notice to, Company under this Tariff, and if Operator fails to comply with such approval or notice requirements, then Operator's Attachment shall be deemed an unauthorized attachment. Unless Operator can demonstrate to Company's reasonable satisfaction that an unauthorized attachment was made more recently, unauthorized attachments are presumed to have existed on Company Facilities for two (2) years. Operator shall be liable for all charges and fees that would have been due under the Tariff for this time period. In addition to charges and fees applicable to the period of unauthorized attachment, Operator shall pay a penalty in the amount of: (1) $25 for each unauthorized attachment within the Communications Space on a Distribution Pole; (2) $500 for each unauthorized attachment above the Communications Space on a Distribution Pole; and (3) $500 for each unauthorized attachment within a duct. Operator shall submit an application for approval of any unauthorized attachment within sixty (60) days of the Attachment's discovery. If Operator fails to submit the required application or to comply with Company's application process, Company may remove the unauthorized attachment at Operator's sole risk and expense.

17. Abandonment by Operator
Operator may at any time abandon the use of a Company Facility hereunder by removing therefrom all of its Attachments and by giving written notice thereof, on a form provided by Company, and no Facility shall be considered abandoned until such notice is received. If notice has been given that Attachment(s) have been removed, but the Attachments are later discovered not to have been removed, then such Attachments shall be deemed unauthorized attachments and handled in accordance with Section 16 of this Tariff.

18. Indemnity
Operator hereby agrees to indemnify, hold harmless, and defend Company from and against any and all loss, damage, cost or expense which Company may suffer or for which Company may be held liable because of interruption of Operator's service to its subscribers, or by reason of bodily injury, including death, to any person, or damage to or destruction of any property, including loss of use thereof, arising out of or in any manner connected with the attachment, operation, and maintenance of the Attachments and other facilities of Operator on the Facilities of Company under this Tariff, or to any such act or omission of Operator's respective representatives, employees, agents or contractors.

19. Limitation of Liability
IN NO EVENT SHALL COMPANY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER THIS TARIFF TO OPERATOR FOR CONSEQUENTIAL, INDIRECT, INCIDENTAL, SPECIAL, EXEMPLARY, PUNITIVE OR ENHANCED DAMAGES, LOST PROFITS OR REVENUES OR DIMINUTION IN VALUE, ARISING OUT OF, OR RELATING TO, OR IN CONNECTION WITH THIS TARIFF, REGARDLESS OF (A) WHETHER SUCH DAMAGES WERE FORESEEABLE; (B) WHETHER OR NOT COMPANY WAS ADVISED OF THE OSSIBILITY OF SUCH DAMAGES OR (C) THE LEGAL OR EQUITABLE THEORY (CONTRACT, TORT OR OTHERWISE) UPSON WHICH THE CLAIM IS BASED. THE LIMITATIONS SET FORTH IN THIS SECTION 19 SHALL NOT APPLY TO DAMAGES OR LIABILITY ARISING FROM THE GROSSLY NEGLIGENT ACTS OR OMISSIONS OR WILLFUL MISCONDUCT OF COMPANY IN PERFORMING ITS OBLIGATIONS UNDER THIS TARIFF.

Continued on Sheet 12-8

Tariff P.A. Continued
(Pole Attachments)

20. Insurance
Operator agrees to obtain and maintain at all times policies of insurance as follows:

(a) Comprehensive bodily injury liability insurance in an amount not less than $5,000,000 for any one occurrence.
(b) Comprehensive property damage liability insurance in an amount not less than $5,000,000 for any one occurrence.
(c) Contractual liability insurance in an amount not less than the foregoing minimums to cover the liability assumed by the Operator under the agreement or indemnity set forth above.

Prior to making Attachments to Company's Facilities, Operator shall furnish to Company two copies of a certificate, from an insurance carrier licensed to do business in Kentucky, stating that policies of insurance have been issued by it to Operator providing for the insurance listed above and that such policies are in force. Such certificate shall state that the insurance carrier will give Company thirty (30) days' prior written notice of any cancellation of or material change in such policies.

21. Performance Assurance
Operator shall furnish Performance Assurance in the following amounts to guarantee the payment of any sums which may become due for attachment charges, inspections, or work performed by Company under this Tariff, including the removal of Attachments upon termination of any license hereunder:

Number of Attachments	Amount per Attachment	Maximum Total
1-7,500	$20	$150,000
7,501-15,000	$10	$225,000
15,001+	$5	$1,000,000

The above-stated amounts are incremental. By way of example, 10,000 Attachments would require Performance Assurance in the amount of $175,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment for the next 2,500 Attachments); 20,000 Attachments would require Performance Assurance in the amount of $250,000 ($20 per Attachment for the first 7,500 Attachments; $10 per Attachment the next 7,500 Attachments; and $5 per Attachment for the last 5,000 Attachments).
The amount of the Performance Assurance shall be calculated by Company annually based on Operator's then-existing number of Attachments. Operator shall provide the Performance Assurance within thirty (30) days of its request by Company.
If Operator proposes to attach a Wireless Facilities to Company Facilities, Operator shall post Performance Assurance in the amount of $1,500 for each Company Facility to which a Wireless Facility is attached. The amount of the Performance Assurance shall not be reduced upon completion of installation or other event.

In the event the Operator provides Performance Assurance in the form of a surety bond or letter of credit, each bond or letter of credit shall contain the provision that it shall not be terminated prior to six (6) months after Company's receipt of written notice of the desire of the bonding or insurance company, or bank, to terminate such bond or letter of credit. Company may waive this requirement if an acceptable replacement is received before the six (6) months has ended. Upon termination of such surety bond or letter of credit, Company shall request Operator to immediately remove its Attachments and all other equipment from Company Facilities. If Operator should fail to complete the removal of all of its Attachments from Company Facilities within sixty (60) days after receipt of such request, then Company may remove Operator's Attachments at Operator's expense and without liability for any damage to Operator's Attachments.

Each surety bond shall be issued by an entity having a minimum A.M. Best rating of A- and/or letter of credit shall be issued by an entity having a minimum Credit Rating of A- by S& P or A3 by Moody's at the time of issuance and at all times the relevant instrument is outstanding.

Continued on Sheet 12-9

Tariff P.A. Continued
(Pole Attachments)

22. Easements
Operator shall secure any right, license or permit from any governmental body, authority or other person or persons which may be required for the construction or maintenance of Attachments of Operator. Company does not convey nor guarantee any easements, rights-of-way or franchises for the construction and maintenance of said Attachments. Operator hereby agrees to indemnify and save harmless Company from any and all claims, including the expenses incurred by Company to defend itself against such claims, resulting from or arising out of the failure of Operator to secure such right, license, permit or easement for the construction or maintenance of said Attachments on Company's poles.

23. Charges and Fees
Operator agrees to pay Company an annual charge per Attachment as set forth in Section 3 of this Tariff in advance, and such other charges as may be provided for herein, for the use of each of Company Facility, any portion of which is occupied by, or reserved at Operator's request for, the Attachments of Operator.

Operator agrees to reimburse Company for all reasonable non-recurring expenses caused by or attributable to Operator's initial Attachments including without limitation the amounts set forth herein before and the expenses of Company in examining poles used but not owned by Company to which Operator proposes to make Attachments.

24. Fees for Additional Attachments
For Attachments made to Company Facilities between billing dates, Operator shall be billed a prorated amount of the annual charge effective on the date of attachment in on the Operator's next bill. Company will not reimburse Operator for, or otherwise prorate Operator's next bill for, any Attachments removed from Company Facilities between billing dates.

25. Payment
Payment of amounts due hereunder is due on the dates or at the times indicated with respect to each such payment. In the event the time for any payment is not specified, such payment shall be due thirty (30) days from the date of the invoice therefor. all amounts not so paid shall accrue interest at a monthly simple interest rate of 1.5% . Where the provisions of the Tariff require any payment by Operator to the Company other than for attachment charges, Company may, at its option, require that the estimated amount thereof be paid in advance of permission to use any pole or the performance by company of any work. In such a case, Company may, in its sole discretion, invoice any deficiency or refund any excess to Operator after the current amount of such payment has been determined.

26. Default or Non-Compliance
If Operator fails to comply with any of the provisions of this Tariff or defaults in the performance of any of its obligations under this Tariff and fails within sixty (60) days, after written notice from Company to correct such default or non-compliance, Company may, in addition to all other remedies under this Tariff, take any one or more of the following actions: terminate the specific permit or permits covering the Company Facilities to which such default or non-compliance is applicable; remove, relocate or rearrange Attachments of Operator to which such default or non-compliance relates, all at Operator's expense; decline to permit additional Attachments hereunder until such default is cured; or in the event of any failure to pay any of the charges, fees or amounts provided in this Tariff or any other substantial default, or of repeated defaults, terminate Operator's right of attachment. Where applicable, Company's written notice of default or non-compliance shall inform Operator of Company's right to remove, relocate or rearrange Attachments of Operator, in the event Operator fails to cure its default or non-compliance within the aforementioned 60-day period. Operator shall remove all Attachments where Company has terminated the right of attachment herein within sixty (60) days of Company providing notice of termination. If Operator fails to remove such Attachments within sixty (60) days, then Company may remove such Attachments at Operator's expense. Company shall have no obligation to store or recover any value for such removed Attachments.

No liability shall be incurred by Company because of any or all such actions except for Company's gross negligence or willful misconduct in any relocation or removal of such equipment. The remedies provided herein are cumulative and in addition to any other remedies available to Company.

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By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff P.A. Continued
(Pole Attachments)

27. Notices
Any notice required by this Tariff shall be deemed properly given if sent to Company's or Operator's authorized representative using any of the following methods: (1) overnight delivery by nationally recognized courier; (2) certified U.S. mail, return receipt requested, postage prepaid; (3) electronically via telecopier or electronic mail; or (4) sent in the manner expressly required herein or by Company's standards. Operators shall, within thirty (30) days of the effective date of this Tariff, or if service is taken for the first time following the effective date of this Tariff, prior to submitting any applications for Attachments, provide Company with the following information for each of their authorized representatives: name, title, mailing address and electronic mailing address. The designation of an authorized representative, as well as the contact information for an existing authorized representative, may be changed at any time by similar notice. Operators are required to maintain current contact information with Company for each of their authorized representatives.

28. Prior Agreements
This Tariff, as of the effective date, terminates, supersedes and replaces any previous agreement or license affecting Company's Facilities and Operator's Attachments covered herein.

29. Assignment
This Tariff shall be binding upon and inure to the benefits of the parties hereto, their respective successors and/or assigns, but Operator shall not assign, transfer or sublet any of the rights hereby granted without the prior written consent of Company, which shall not be unreasonably withheld, and any such purported assignment, transfer or subletting without such consent shall be void.

30. Performance Waiver
Neither party shall be considered in default in the performance of its obligations herein, or any of them, to the extent that performance is delayed or prevented due to causes beyond the control of said party, including but not limited to, Acts of God or the public enemy, war, revolution, civil commotion, blockade or embargo, acts of government, any law, order, proclamation, regulation, ordinance, demand, or requirement of any government, fires, explosions, cyclones, floods, unavoidable casualties, quarantine, restrictions, strikes, labor disputes, lock-outs, and other causes beyond the reasonable control of either of the parties.

31. Preservation of Remedies
No delay or omission in the exercise of any power or remedy herein provided or otherwise available to the Company shall impair or affect its right thereafter to exercise the same.

Tariff T.S.
(Temporary Service)

Availability of Service
Where capacity is available, Company will install service for temporary lighting and power service to customers who have demonstrated to the Company's satisfaction that the requested temporary service will be temporary in nature. Residential customers will be supplied with 100 amp single phase service. All other customer classes will be supplied at voltage levels applicable to the class of business.

Rate *(Tariff Code 019)*
Temporary service will be supplied under any published tariff applicable to the class of business of the Customer, when the Company has available unsold capacity of lines, transforming and generating equipment, with an additional charge of the total cost of installation, connection, disconnection and removal of service.

Charges
The same minimum charge as provided for in any applicable tariff shall be applicable to such temporary service and for not less than one full monthly minimum.

Customer's requesting temporary service will be charged a minimum temporary service installation charge, payable in advance, based on the Company's actual cost of installation, connection, disconnection, and removal of the required facilities to provide temporary service.

~~**Delayed Payment Charge**~~
~~Bills under this tariff are due and payable within fifteen (15) days after their mailing date. All accounts not paid in full by the next billing date will be assessed an additional charge of 5% of the outstanding unpaid balance.~~

Terms of Service
Temporary Service will be in effect for a period of 180 days from the date of installation. The Company may grant extensions based on customer's demonstration of continued need for temporary service.

The Company may discontinue temporary service at the end of the 180 days, or at the end of any extended period of time after the initial 180 days.

Special Terms and Conditions
A deposit equal to the full estimated amount of the bill and/or construction costs under this tariff may be required. This tariff is not available to customers permanently located, whose energy requirements are of a seasonal nature. See Terms and Conditions of Service.

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Tariff U.D.C.
(Underground Differential Cost Schedule)

Underground Service Plan for Residential Subdivisions and Residential Service Laterals

Applicable
To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, and R.S.D.

Rate

PRIMARY AND SECONDARY DISTRIBUTION SYSTEM

Charge: **$ 65.29** per foot of lot width (average x number of lots) when Company performs trenching, conduit installation, and backfilling to Company specifications.

Charge: **$ 31.95** per foot of lot width (average x number of lots) when Customer performs trenching, conduit installation, and backfilling to Company specifications.

SERVICE LATERALS

FROM OVERHEAD FACILITIES

Charge: **$ 29.67** per foot of trench length from Overhead Facilities when Company performs trenching, conduit installation, and backfilling to Company

Charge: **$ 11.04** per foot of trench length from Overhead Facilities when Customer performs trenching, conduit installation, and backfilling to Company

FROM UNDERGROUND FACILITIES

Charge: **$ 23.83** per foot of trench length from Underground Facilities when Company performs trenching, conduit installation, and backfilling to Company

Charge: **$ 5.70** per foot of trench length from Underground Facilities when Customer performs trenching, conduit installation, and backfilling to Company

REPLACEMENT OF USEFUL OVERHEAD SERVICE DROP

Charge: **$ 200.00** for each removal in addition to any underground differential costs.

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Rider A.F.S.
(Alternate Feed Service Rider)

Availability of Service
Standard Alternate Feed Service (AFS) is a premium service providing a redundant distribution service provided through a redundant distribution line and distribution station transformer, with automatic or manual switch-over and recovery, which provides increased reliability for distribution service. Rider AFS applies to those customers requesting new or upgraded AFS after the effective date of this rider. Rider AFS also applies to existing customers that desire to maintain redundant service when the Company must make expenditures in order to continue providing such service.

Rider AFS is available to customers who request a primary voltage alternate feed and who normally take service under Tariffs M.G.S.-TOD, L.G.S., L.G.S.-TOD, I.G.S., or M.W. for their basic service requirements, provided that the Company has adequate capacity in existing distribution facilities, as determined by the Company, or if changes can be made to make capacity available. AFS provided under this rider may not be available at all times, including emergency situations.

System Impact Study Charge
The Company shall charge the customer for the actual cost incurred by the Company to conduct a system impact study for each site reviewed. The study will consist of, but is not limited to, the following: (1) identification of customer load requirements, (2) identification of the potential facilities needed to provide the AFS, (3) determination of the impact of AFS loading on all electrical facilities under review, (4) evaluation of the impact of the AFS on system protection and coordination issues including the review of the transfer switch, (5) evaluation of the impact of the AFS request on system reliability indices and power quality, (6) development of cost estimates for any required system improvements or enhancements required by the AFS, and (7) documentation of the results of the study. The Company will provide to the customer an estimate of charges for this study.

Equipment and Installation Charge
The customer shall pay, in advance of construction, a nonrefundable amount for all equipment and installation costs for all dedicated and/or local facilities provided by the Company required to furnish either a new or upgraded AFS. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. The customer will not acquire any title in said facilities by reason of such payment. The equipment and installation charge shall be determined by the Company and shall include, but not be limited to, the following: (1) all costs associated with the AFS dedicated and/or local facilities provided by the Company and (2) any costs or modifications to the customer's basic service facilities.

The customer is responsible for all costs associated with providing and maintaining phone service for use with metering to notify the Company of a transfer of service to the AFS or return to basic service.

Transfer Switch Provision
In the event the customer receives basic service at primary voltage, the customer shall install, own, maintain, test, inspect, operate and replace the transfer switch. Customer-owned switches are required to be at primary voltage and must meet the Company's engineering, operational and maintenance specifications. The Company reserves the right to inspect the customer-owned switches periodically and to disconnect the AFS for adverse impacts on reliability or safety.

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of $15.75 for the Company to annually test the transfer switch / control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module.

Continued on Sheet 15-2

Rider A.F.S. Continued
(Alternate Feed Service Rider)

Transfer Switch Provision Continued

In the event a customer receives basic service at secondary voltage and requests AFS, the Company will provide the AFS at primary voltage. The Company will install, own, maintain, test, inspect and operate the transfer switch and control module. The customer shall pay the Company a nonrefundable amount for all costs associated with the transfer switch installation. The payment shall be grossed-up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer is required to pay the monthly rate for testing and ongoing maintenance costs defined above. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes.

After a transfer of service to the AFS, a customer utilizing a manual or semi-automatic transfer switch shall return to the basic service within one (1) week or as mutually agreed to by the Company and customer. In the event system constraints require a transfer to be expedited, the Company will endeavor to provide as much advance notice as possible to the customer. However, the customer shall accomplish the transfer back to the basic service within ten minutes if notified by the Company of system constraints. In the event the customer fails to return to basic service within 12 hours, or as mutually agreed to by the Company and customer, or within ten minutes of notification of system constraints, the Company reserves the right to immediately disconnect the customer's load from the AFS source. If the customer does not return to the basic service as agreed to, or as requested by the Company, the Company may also provide 30 days' notice to terminate the AFS agreement with the customer.

The customer shall make a request to the Company for approval three days in advance for any planned switching.

Monthly AFS Capacity Reservation Demand Charge
Monthly AFS charges will be in addition to all monthly basic service charges paid by the customer under the applicable tariff.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is $6.38 per kW.

AFS Capacity Reservation
The customer shall reserve a specific amount of AFS capacity equal to, or less than, the customer's average maximum requirements, but in no event shall the customer's AFS capacity reservation under this rider exceed the capacity reservation for the customer's basic service under the appropriate tariff. The Company shall not be required to supply AFS capacity in excess of that reserved except by mutual agreement.

If the customer plans to increase the AFS demand at anytime in the future, the customer shall promptly notify the Company of such additional demand requirements. The customer's AFS capacity reservation and billing will be adjusted accordingly. The customer will pay the Company the actual costs of any and all additional dedicated and/or local facilities required to provide AFS in advance of construction and pursuant to an AFS construction agreement. If customer exceeds the agreed upon AFS capacity reservation, the Company reserves the right to disconnect the AFS. If the customer's AFS metered demand exceeds the agreed upon AFS capacity reservation, which jeopardizes company facilities or the electrical service to other customers, the Company reserves the right to disconnect the AFS immediately. If the Company agrees to allow the customer to continue AFS, the customer will be required to sign a new AFS agreement reflecting the new AFS capacity reservation. In addition, the customer will promptly notify Kentucky Power regarding any reduction in the AFS capacity reservation.

The customer may reserve partial-load AFS capacity, which shall be less than the customer's full requirements for basic service subject to the conditions in this provision. Prior to the customer receiving partial-load AFS capacity, the customer shall be required to demonstrate or provide evidence to the Company that they have installed demand-controlling equipment that is capable of curtailing load when a switch has been made from the basic service to the AFS. The Company reserves the right to test and verify the customer's ability to curtail load to meet the agreed upon partial-load AFS capacity reservation.

Continued on Sheet 15-3

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Rider A.F.S. Continued
(Alternate Feed Service Rider)

Determination of Billing Demand
Full-Load Requirement:
For customers requesting AFS equal to their load requirement for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly billing demand on the AFS during the past 11 months, or (c) the customer's basic service capacity reservation, or (d) the customer's highest previously established monthly billing demand on the basic service during the past 11 months.

Partial-Load Requirement:
For customers requesting partial-load AFS capacity reservation that is less than the customer's full requirements for basic service, the AFS billing demand shall be taken each month as the single-highest 15-minute integrated peak on the AFS as registered during the month by a demand meter or indicator, but the monthly AFS billing demand so established shall in no event be less than the greater of (a) the customer's AFS capacity reservation, or (b) the customer's highest previously established monthly metered demand on the partial-load AFS during the past 11 months.

~~**Delayed Payment Charge**~~
~~This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.~~

Terms of Contract
The AFS agreement under this rider will be made for a period of not less than one year and shall remain in effect thereafter until either party shall give at least six months' written notice to the other of the intention to discontinue service under the terms of this rider.

Disconnection of AFS under this rider due to reliability or safety concerns associated with customer-owned transfer switches will not relieve the customer of payments required hereunder for the duration of the agreement term.

Special Terms and Conditions
This rider is subject to the Company's Terms and Conditions of Service.

Upon receipt of a request from the customer for non-standard AFS (AFS which includes unique service characteristics different from standard AFS), the Company will provide the customer with a written estimate of all costs, including system impact study costs, and any applicable unique terms and conditions of service related to the provision of the non-standard AFS. An AFS agreement will be filed with the Commission under the 30-day filing procedures. The AFS agreement shall provide full disclosure of all rates, terms and conditions of service under this rider, and any and all agreements related thereto.

The Company will have sole responsibility for determining the basic service circuit and the AFS circuit.

The Company assumes no liability should the AFS circuit, transfer switch, or other equipment required to provide AFS fail to operate as designed, is unsatisfactory, or is not available for any reason.

Rider R.P.O.
(Renewable Power Option Rider)

Availability of Service
Available to customers taking metered service under the Company's R.S., R.S.D. , R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., ~~C.S. Coal,~~ and M.W. tariffs.

Participation in this program under Option A may be limited by the ability of the Company to procure renewable energy certificates (RECs) from Renewable Resources. If the total of all kWh under contract under this Rider equals or exceeds the Company's ability to procure RECs, the Company may suspend the availability of this Rider to new participants.

Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand.

Conditions of Service
Customers who wish to support the development of electricity generated by Renewable Resources may under Option A contract to purchase each month a specific number of fixed kWh blocks, or choose to cover all of their monthly usage.

Renewable Resources shall be defined as Wind, Solar Photovoltaic, Biomass Co-Firing of Agricultural crops and all energy crops, Hydro (as certified by the Low Impact Hydro Institute), Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-Firing of All Woody Waste including mill residue, but excluding painted or treated lumber. All REC's purchased under Option A of this tariff shall be retained or retired by the Company on behalf of customers.

Rates

Option A
In addition to the monthly charges determined according to the Company's tariff under which the customer takes metered service, the customer shall also pay the following rate for the REC option of their choosing. The charge will be applied to the customer's bill as a separate line item.

The Company will provide customers at least 30-days' advance notice of any change in the Rate. At such time, the customer may modify or cancel their automatic monthly purchase agreement. Any cancellation will be effective at the end of the current billing period when notice is provided.

	Block Purchase Charge ($ per 100 kWh block)	All Usage Purchase Charge per kWh consumed
A1. Solar RECs	$0~~1~~.5~~0~~0/month	$0.005~~10~~
A2. Wind RECs	$0~~1~~.5~~0~~0/month	$0.0~~1~~05
A3. Hydro & Other RECs	$0.5~~3~~0/month	$0.005~~3~~

Option B
Charges for service under option B of this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect a combination of the firm service rates otherwise available to the Customer and the cost of the renewable energy resource being directly contracted for by the Customer.

Continued on Sheet 16-2

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TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
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Rider R.P.O. Continued
(Renewable Power Option Rider)

Term
This is a voluntary program.

Under Option A Customers may participate through a one-time purchase, or establish an automatic monthly purchase agreement. Any payments under this program are nonrefundable. Customers participating under Option A may terminate service under this Rider by notifying the Company with at least thirty (30) days prior notice.

Under Option B, the term of the agreement will be determined in the written agreement between the Company and the Customer.

Special Terms and Conditions
This Rider is subject to the Company's Terms and Conditions of Service and all provisions of the tariff under which the customer takes service, including all payment provisions. The Company may deny or terminate service under this Rider to customers who are delinquent in payment to the Company.

Funds collected under this Renewable Power Option Rider will be used solely to purchase RECs for the program.

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Tariff N.U.G.
(Non-Utility Generator)

Availability of Service

This tariff is unavailable to new participants. This tariff is applicable to customers with generation facilities which have a total design capacity of over 1,000 kW that intends to schedule, deliver and sell the net electric output of the facility at wholesale, and who require ~~Commissioning Power, Startup Power and/or~~ Station Power service from the Company.

Service to any load that is electrically isolated from the Customer's generator shall be separately metered and provided in accordance with the generally available demand-metered tariff appropriate for such service to the Customer.

This tariff is not available for standby, backup, maintenance, or supplemental service for wholesale or retail loads served by Customer's generator.

Definitions

~~1. **Commissioning Power** - The electrical energy and capacity supplied to the customer prior to the commercial operation of the customer's generator, including initial construction and testing phases.~~

~~2.~~ **Station Power** - The electrical energy and capacity supplied to the customer to serve the auxiliary loads at the Customer's generation facilities, usually when the Customer's generator is not operating. Station Power does not include Startup Power.

~~3. **Startup Power** - The electrical energy and capacity supplied to the customer following a planned or forced outage of the customer's generator for the purpose of returning the customer's generator to synchronous operation.~~

~~**Commissioning Power Service**~~

~~Customers requiring Commissioning Power shall take service under Tariff T.S. or by special agreement with the Company. The Customer shall coordinate its construction and testing with the Company to ensure that the customer's operations do not cause any undue interference with the Company's obligations to provide service to its other customers or impose a burden on the Company's system or any system interconnected with the Company.~~

Station Power Service

Customers requiring Station Power shall take service under the generally available demand-metered tariff appropriate for the Customer's Station Power requirements.

Station Contract Capacity – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Station Power requirements that the Company is expected to supply under the generally available demand-metered tariff appropriate for the customer.

~~Startup Power Service~~Transmission Service

Transmission Provider - The entity providing transmission service to customers in the Company's service territory. Such entity may be the Company or a regional transmission entity.

Prior to taking service under this tariff, the Customer must have a fully executed Interconnection and Operation Agreement with the Company and/or the Transmission Provider or an unexecuted agreement filed with the Federal Energy Regulatory Commission under applicable procedures.

~~Should the customer's use of Startup Power result in any charges for Transmission Congestion from the Transmission Provider, such charges, including any applicable taxes or assessments, shall be paid by or passed through to the customer without markup.~~ Transmission Congestion is the condition that exists when market participants seek to dispatch in a pattern that would result in power flows that cannot be physically accommodated by the system.

Term of Contract

Contracts under this tariff will be made for an initial period of not less than one year and shall remain in effect thereafter until either party shall give at least 6 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than one year.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts will be made in multiples of 100 kW.

Continued on Sheet 17-2

Tariff N.U.G. Continued
(Non-Utility Generator)

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service.

This tariff shall not obligate the Company to purchase or pay for any capacity or energy produced by the Customer's generator.

Customers desiring to provide ~~Startup and~~ Station Power from other generation facilities, owned by the same individual business entity that are not located on the site of the customer's generator (remote self-supply), shall take service under the terms and conditions contained within the applicable Open Access Transmission Tariff as filed with and accepted by the Federal Energy Regulatory Commission.

~~Customers requiring Startup Power have the option of contracting for such service under the terms of this tariff or under the generally available demand-metered tariff appropriate for the customer's Startup Power requirements.~~

~~**Startup Contract Capacity** – The Customer shall contract for a definite amount of electrical capacity in kW sufficient to meet the maximum Startup Power requirements that the Company is expected to supply.~~

~~**Startup Duration** – The Customer shall contract for a definite number of hours sufficient to meet the maximum period of time for which the Company is expected to supply Startup Power.~~

~~**Startup Frequency** – The Customer shall contract for a definite number of startup events sufficient to meet the maximum number of times per year that the Company is expected to supply Startup Power.~~

~~**Other Startup Characteristics** – The customer shall provide to the Company other information regarding the customer's Startup Power requirements, including, but not limited to, anticipated time-of-use and seasonal characteristics.~~

Tariff N.M.S.
(Net Metering Service)

Availability of Service
Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible electric generating facilities in service before May 15, 2021 shall be entitled to continue to take service under this tariff, as it may be amended from time to time by the Commission, until the earlier of: (i) May 14, 2046; or (ii) the date the customer's modification of the eligible electric generating facility results in a material increase in the eligible electric generating facility's capacity.

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

Metering
Net energy metering shall be accomplished using a standard kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

Billing/Monthly Charges
Monthly charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility. Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill. If the customer's net energy is negative during a billing period, the customer shall be credited in the next billing period for the kWh difference. If time-of-day metering is used, energy flows in both directions shall be netted and accounted for at the specific time-of-use in accordance with the provisions of the customer's standard tariff and this Net Metering Service Tariff. When the customer elects to no longer take service under this Net Metering Service Tariff, any unused credit shall revert to the Company. Excess electricity credits are not transferable between customers or locations.

Continued on Sheet 18-2

Tariff N.M.S. Continued
(Net Metering Service)

Application and Approval Process
The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

Level 1 and Level 2 Definitions

Level 1
A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

Continued on Sheet 18-3

Tariff N.M.S. Continued
(Net Metering Service)

Level 1 Continued
If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

Level 2
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

Continued on Sheet 18-4

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Tariff N.M.S. Continued
(Net Metering Service)

Application, Inspection and Processing Fees
No application fee or other review, study, or inspection or witness test fees will be charged by the company for Level I application.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $50. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

Terms and Conditions for Interconnection
To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company’s Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company’s system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company‘s electric system. At all times when the generating facility is being operated in parallel with Company’s electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company’s electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company’s ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

Continued on Sheet 18-5

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Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

Continued on Sheet 18-6

Tariff N.M.S. Continued
(Net Metering Service)

Terms and Conditions for Interconnection Continued

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Term of Contract
Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

Special Terms and Conditions
This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

Continued on Sheet 18-7

Tariff N.M.S. Continued
(Net Metering Service)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: (   ) Phone: (   )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip: Electric Service

Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 18-8

Tariff N.M.S. Continued
(Net Metering Service)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ________________________

Continued on Sheet 18-9

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1:

1 Kentucky Power Company (Company) shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

Continued on Sheet 18-10

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Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity is allowed without approval.

Continued on Sheet 18-11

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 18-12

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: ____ **Date:** ____

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: _______________________ to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

____

Approved by: _____________________________ **Date**:__________________________________

Printed Name: ____________________________**Title:** ___________________________________

Continued on Sheet 18-13

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff N.M.S. Continued
(Net Metering Service)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).

Submit this Application (along with the application fee of $100) to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name:

Mailing Address:

City: State: Zip:

Phone: ( ) Phone: ( )

E-mail address:

Service Location

Name:

Street Address:

City: State: Zip:

Electric Service Account Number

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 18-14

Tariff N.M.S. Continued
(Net Metering Service)

APPPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility: ____

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ________________________________

Continued on Sheet 18-15

Tariff N.M.S. Continued
(Net Metering Service)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this ______ day of ___, 20___, by and between Kentucky Power Company (Company), and ___________________________________ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location: ____

Generator Size and Type:

____

Now, Therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

Continued on Sheet 18-16

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

Continued on Sheet 18-17

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

Continued on Sheet 18-18

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity is allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 18-19

Tariff N.M.S. Continued
(Net Metering Service)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature:	______________________________	**Date:**	______________________________
Printed Name:	______________________________	**Title:**	______________________________
Company Signature:	______________________________	**Date:**	______________________________
Printed Name:	______________________________	**Title:**	______________________________

Continued on Sheet 18-20

Tariff N.M.S. Continued
(Net Metering Service)

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.

- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.

- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

Tariff N.M.S. II
(Net Metering Service II)

Availability of Service

Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of one percent (1%) of the Company's single hour peak load in Kentucky during the previous year. If the cumulative generating capacity of net metering systems reaches 1% of the Company's single hour peak load during the previous year, upon Commission approval, the Company's obligation to offer net metering to a new customer-generator may be limited. An eligible customer- generator shall mean a retail electric customer of the Company with a generating facility that:

(1) Generates electricity using solar energy, wind energy, biomass or biogas energy, or hydro energy;
(2) Has a rated capacity of not greater than forty-five (45) kilowatts;
(3) Is located on the customer's premises;
(4) Is owned and operated by the customer;
(5) Is connected in parallel with the Company's electric distribution system; and
(6) Has the primary purpose of supplying all or part of the customer's own electricity requirements.

At its sole discretion, the Company may provide Net Metering to other customer-generators not meeting all the conditions listed above on a case-by-case basis.

Eligible generating facilities may take service, for a period of 25 years after the eligible generating facility is first placed in service, under the two-part rate structure and netting periods of this tariff in effect at the time the eligible electric generating facility is first placed in service.

Customers served under this optional offering will not be eligible for the Company's Equal Payment Plan (Budget) or Average Monthly Payment Plan (AMP).

The term "Customer" hereinafter shall refer to any customer requesting or receiving Net Metering services under this tariff.

Metering

Net energy metering shall be accomplished using a time of use ("TOU") kilowatt-hour meter capable of measuring the flow of electricity in two (2) directions. If the existing electrical meter installed at the customer's facility is not capable of measuring the flow of electricity in two directions, the Company will provide the customer with the appropriate metering at no additional cost to the customer. If the customer requests any additional meter or meters or if distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

Billing Charges

All net billing kWh and kW in each netting period, accumulated for the billing period, shall be charged at the rates applicable under the Company's standard service tariff under which the customer would otherwise be served, absent the customer's electric generating facility.

Energy charges under the customer's standard tariff shall be applied to the customer's net energy for the billing period to the extent that the net energy exceeds zero. If the customer's net energy is zero or negative during the billing period, the customer shall pay only the non- energy charge portions of the standard tariff bill.

All excess customer generation, (net negative energy or "NNE"), accumulated for the billing period, shall be credited at the avoided cost rate of 0.09746 $/kWh for Residential service and 0.09657 $/kWh for non-residential service each billing period.

Bill credits to customers for NNE at the avoided cost rate each billing period is a purchased power expense and shall be recovered from all customers through the Company's Purchased Power Adjustment Rider. If the NNE credit exceeds the customer's billed energy charges, along with any riders that are based on a per kWh charge, during the billing period, the amount in excess will be carried over for use in subsequent billing periods.

Continued on Sheet 19-2

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff N.M.S. II Continued
(Net Metering Service II)

Application and Approval Process
The Customer shall submit an Application for Interconnection and Net Metering ("Application") and receive approval from the Company prior to connecting the generator facility to the Company's system.

Applications will be submitted by the Customer and reviewed and processed by the Company according to either Level 1 or Level 2 processes defined below.

The Company may reject an Application for violations of any code, standard, or regulation related to reliability or safety; however, the Company will work with the Customer to resolve those issues to the extent practicable.

Customers may contact the Company to check on the status of an Application or with questions prior to submitting an Application. Company contact information can be found on Kentucky Power Company's Application Form or on the Company's website.

Level 1 and Level 2 Definitions

Level 1
A Level 1 Application shall be used if the generating facility is inverter-based and is certified by a nationally recognized testing laboratory to meet the requirements of Underwriters Laboratories Standard 1741 "Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources" (UL 1741).

The Company will approve the Level 1 Application if the generating facility also meets all of the following conditions:

(1) For interconnection to a radial distribution circuit, the aggregated generation on the circuit, including the proposed generating facility, will not exceed 15% of the Line Section's most recent annual one hour peak load. A line section is the smallest part of the primary distribution system the generating facility could remain connected to after operation of any sectionalizing devices.
(2) If the proposed generating facility is to be interconnected on a single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generating facility, will not exceed the smaller of 20 kVA or the nameplate rating of the transformer.
(3) If the proposed generating facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.
(4) If the generating facility is to be connected to three-phase, three wire primary Company distribution lines, the generator shall appear as a phase-to-phase connection at the primary Company distribution line.
(5) If the generating facility is to be connected to three-phase, four wire primary Company distribution lines, the generator shall appear to the primary Company distribution line as an effectively grounded source.
(6) The interconnection will not be on an area or spot network.
(7) The Company does not identify any violations of any applicable provisions of IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems."
(8) No construction of facilities by the Company on its own system will be required to accommodate the generating facility.

If the generating facility does not meet all of the above listed criteria, the Company, in its sole discretion, may either: 1) approve the generating facility under the Level 1 Application if the Company determines that the generating facility can be safely and reliably connected to the Company's system; or 2) deny the Application as submitted under the Level 1 Application.

The Company shall notify the customer within 20 business days whether the Application is approved or denied, based on the criteria provided in this section.

Continued on Sheet 19-3

Tariff N.M.S. II Continued
(Net Metering Service II)

Level 1 Continued
If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the time to process the Application.

When approved, the Company will indicate by signing the approval line on the Level 1 Application Form and returning it to the customer. The approval will be subject to successful completion of an initial installation inspection and witness test if required by the Company. The Company's approval section of the Application will indicate if an inspection and witness test are required. If so, the customer shall notify the Company within 3 business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within 10 business days of completion of the generator facility installation or as otherwise agreed to by the Company and the customer. The customer may not operate the generating facility until successful completion of such inspection and witness test, unless the Company expressly permits operational testing not to exceed two hours. If the installation fails the inspection or witness test due to noncompliance with any provision in the Application and Company approval, the customer shall not operate the generating facility until any and all noncompliance is corrected and re-inspected by the Company.

If the Application is denied, the Company will supply the customer with reasons for denial. The customer may resubmit under Level 2 if appropriate.

Level 2
A Level 2 Application is required under any of the following:

(1) The generating facility is not inverter based;
(2) The generating facility uses equipment that is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741; or
(3) The generating facility does not meet one or more of the additional conditions under Level 1.

The Company will approve the Level 2 Application if the generating facility meets the Company's technical interconnection requirements, which are based on IEEE 1547. The Company shall make its technical interconnection requirements available online and upon request.

The Company will process the Level 2 Application within 30 business days of receipt of a complete Application. Within that time the Company will respond in one of the following ways:

(1) The Application is approved and the Company will provide the customer with an Interconnection Agreement to sign.
(2) If construction or other changes to the Company's distribution system are required, the cost will be the responsibility of the customer. The Company will give notice to the customer and offer to meet to discuss estimated costs and construction timeframe. Should the customer agree to pay for costs and proceed, the Company will provide the customer with an Interconnection Agreement to sign within a reasonable time.
(3) The Application is denied. The Company will supply the customer with reasons for denial and offer to meet to discuss possible changes that would result in Company approval. Customer may resubmit Application with changes.

If the Application lacks complete information, the Company shall notify the customer that additional information is required, including a list of such additional information. The time between notification and receipt of required additional information will add to the 30-business-day target to process the Application.

Continued on Sheet 19-4

Tariff N.M.S. II Continued
(Net Metering Service II)

Level 2 Continued
The Interconnection Agreement will contain all the terms and conditions for interconnection consistent with those specified in this tariff, inspection and witness test requirements, description of and cost of construction or other changes to the Company's distribution system required to accommodate the generating facility, and detailed documentation of the generating facilities which may include single line diagrams, relay settings, and a description of operation.

The customer may not operate the generating facility until an Interconnection Agreement is signed by the customer and Company and all necessary conditions stipulated in the agreement are met.

Application, Inspection and Processing Fees
No application fee or other review, study, or inspection or witness test fees will be charged by the Company for Level 1 applications.

The Company will require each customer to submit with each Level 2 Application a non-refundable application, inspection and processing fee of $100. In the event the Company determines an impact study is necessary with respect to a Level 2 Application, the customer shall be responsible for any reasonable costs up to $1,000 for the initial impact study. The Company shall provide documentation of the actual cost of the impact study. Any other studies requested by the customer shall be at the customer's sole expense.

Terms and Conditions for Interconnection
To interconnect to the Company's distribution system, the customer's generating facility shall comply with the following terms and conditions:

(1) The Company shall provide the customer net metering services, without charge for standard TOU metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

(2) The customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance and safe operation of the generating facility. Upon reasonable request from the Company, the customer shall demonstrate generating facility compliance.

(3) The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by IEEE and accredited testing laboratories such as Underwriters Laboratories; (b) the NEC as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

(4) Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

Continued on Sheet 19-5

Tariff N.M.S. II Continued
(Net Metering Service II)

Terms and Conditions for Interconnection Continued

(5) Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

(6) Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

(7) After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance, and operation of the generating facility comply with the requirements of this tariff.

(8) For Level 1 and 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company's electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring that the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company's safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

(9) Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability, or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

Continued on Sheet 19-6

Tariff N.M.S. II Continued
(Net Metering Service II)

Terms and Conditions for Interconnection Continued

(10) Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

(11) To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining, or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

(12) The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for both Level 1 and Level 2 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

(13) By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

(14) A customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

(15) The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Term of Contract

Any contract required under this tariff shall become effective when executed by both parties and shall continue in effect until terminated. The contract may be terminated as follows: (a) Customer may terminate the contract at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the contract or the rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

Special Terms and Conditions

This tariff is subject to the Company's Terms and Conditions of Service and all provisions of the standard service tariff under which the customer takes service. This tariff is also subject to the applicable provisions of the Company's Technical Requirements for Interconnection.

Continued on Sheet 19-7

DATE OF ISSUE: June 29, 2023
DATE EFFECTIVE: January 1, 2024
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff N.M.S. II Continued
(Net Metering Service II)

Application For Interconnection And Net Metering – Level 1

Use this Application only for: 1.) a generating facility that is inverter based and certified by a nationally recognized testing laboratory to meet the requirements of UL 1741, 2.) less than or equal to 45 kW generation capacity, and 3.) connecting to Kentucky Power distribution system.

Submit this Application to:

D.G. Coordinator American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoodinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to-date information http://www.kentuckypower.com)

Applicant

Name: ______________________________

Mailing Address: ______________________________

City: __________ State: __________ Zip: __________

Phone: (______) Phone: (____________________)

E-mail address: ______________________________

Service Location

Name: ______________________________

Street Address: ______________________________

City: __________ State: __________ Zip: __________

Electric Service Account Number ______________________________

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 19-8

Tariff N.M.S. II Continued
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 1 – CONTINUED

Equipment Qualifications

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Inverter Manufacturer: Model:

Inverter Power Rating: Voltage Rating:

Power Rating of Energy Source (i.e., solar panels, wind turbine):

Battery Storage: ( ) Yes ( ) No If Yes, Battery Power Rating:

Attach documentation showing that inverter is certified by a nationally recognized testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date: ________________________

Continued on Sheet 19-9

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1:

1 The Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter or meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2 Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3 The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4 Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5 Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

6 Customer shall be responsible for protecting, at customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

Continued on Sheet 19-10

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

7 After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8 For Level 1 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company’s electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company’s safety and operating protocols.

The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9 Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

10 Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components that meet UL 1741 certification requirements for Level 1 facilities and not resulting in increases in generating facility capacity are allowed without approval.

Continued on Sheet 19-11

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

11 To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12 The Customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy) for Level 1 generating facilities. Customer shall, upon request, provide Company with proof of such insurance at the time that application is made for net metering.

13 By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14 Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the Customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15 The customer shall retain any and all Renewable Energy Credits ("RECs") that may be generated by their generating facility.

Continued on Sheet 19-12

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 1, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute. I hereby certify that, to the best of my knowledge, all of the information provided in this Application is true, and I agree to abide by all the Terms and Conditions included in this Application for Interconnection and Net Metering and Company's Net Metering Tariff.

Customer Signature: ______________________________ **Date:** ______________________

COMPANY APPROVAL SECTION

When signed below by a Company representative, Application for Interconnection and Net Metering is approved subject to the provisions contained in this Application and as indicated below.

Company inspection and witness test: ( ) Required ( ) Waived

If Company inspection and witness test is required, Customer shall notify the Company within three (3) business days of completion of the generating facility installation and schedule an inspection and witness test with the Company to occur within ten (10) business days of completion of the generating facility installation or as otherwise agreed to by the Company and the Customer. Unless indicated below, the Customer may not operate the generating facility until such inspection and witness test is successfully completed. Additionally, the Customer may not operate the generating facility until all other terms and conditions in the Application have been met.
Call: to schedule an inspection and witness test.

Pre-Inspection operational testing not to exceed two (2) hours: ( ) Allowed ( ) Not Allowed

If Company inspection and witness test is waived, operation of the generating facility may begin when installation is complete, and all other terms and conditions in the Application have been met.

Additions, Changes, or Clarifications to Application Information: ( ) None ( ) As specified here:

____

Approved by: ______________________________ **Date**: ______________________

Printed Name: ______________________________ **Title:** ______________________

Continued on Sheet 19-13

Tariff N.M.S. II Continued
(Net Metering Service II)

Application for Interconnection and Net Metering – Level 2

Use this Application form for connecting to the Kentucky Power distribution system and: 1.) the generating facility is not inverter based or is not certified by a nationally recognized testing laboratory to meet the requirements of UL 1741 or 2.) does not meet any of the additional conditions under a Level 1 Application (inverter based and less than or equal to 45kW generation).

Submit this Application (along with the application fee of $100) to:

D.G. Coordinator
American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
614-716-4020 Office / 614-716-1414 Fax
dgcoordinator@aep.com

(Contact person listed is subject to change. Please visit our website for up-to date information http://www.kentucky power.com)

Applicant

Name: ____

Mailing Address: ____

City: ____________ State: ____________ Zip: ____________

Phone: (______) Phone: (______________________)

E-mail address: ____

Service Location

Name: ____

Street Address: ____

City: ____________ State: ____________ Zip: ____________

Electric Service Account Number ____

Provide names and contact information for other contractors, installers, or engineering firms involved in the design and installation of the generating facilities:

Alternate Contacts

Name	Company	Telephone/Email

Continued on Sheet 19-14

Tariff N.M.S. II Continued
(Net Metering Service II)

APPLICATION FOR INTERCONNECTION AND NET METERING, LEVEL 2 - CONTINUED

Equipment Qualifications

Total Generating Capacity (kW) of the Generating Facility:

Type of Generator: ( ) Inverter-Based ( ) Synchronous ( ) Induction

Energy Source: ( ) Solar ( ) Wind ( ) Hydro ( ) Biogas ( ) Biomass

Attach documentation showing that inverter is certified by a nationally recognizes testing laboratory to meet the requirements of UL 1741.

Attach site drawing or sketch showing locations of Kentucky Power Company meter, energy source, accessible disconnect switch and inverter.

Attach single line drawing showing all electrical equipment from the metering location to the energy source including switches, fuses, breakers, panels, transformers, inverters, energy source, wire size, equipment ratings, and transformer connections.

Expected Start-up Date:_______________________________________

Continued on Sheet 19-15

Tariff N.M.S. II Continued
(Net Metering Service II)

Interconnection Agreement – Level 2

This Interconnection Agreement (Agreement) is made and entered into this ______ day of ___, 20__, by and between Kentucky Power Company (Company), and ___________________________________ (Customer). Company and Customer are hereinafter sometimes referred to individually as "Party" or collectively as "Parties"

Witnesseth:

Whereas, Customer is installing, or has installed, generating equipment, controls, and protective relays and equipment (Generating Facility) used to interconnect and operate in parallel with Company's electric system, which Generating Facility is more fully described in Exhibit A, attached hereto and incorporated herein by this Agreement, and as follows:

Location:____

Generator Size and Type:____

Now, therefore, in consideration thereof, Customer and Company agree as follows:

Company agrees to allow Customer to interconnect and operate the generating Facility in parallel with the Company's electric system and Customer agrees to abide by Company's Net Metering Tariff and all Terms and Conditions listed in this Agreement including any additional conditions listed in Exhibit A.

Continued on Sheet 19-16

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2:

To interconnect to the Kentucky Power Company (Company) distribution system, the customer's generating facility shall comply with the following terms and conditions:

1. Company shall provide customer net metering services, without charge for standard metering equipment, through a standard kilowatt-hour metering system capable of measuring the flow of electricity in two (2) directions. If the customer requests any additional meter/meters or distribution upgrades are needed to monitor the flow in each direction, such installations shall be at the customer's expense.

2. Customer shall install, operate, and maintain, at customer's sole cost and expense, any control, protective, or other equipment on the customer's system required by the Company's technical interconnection requirements based on IEEE 1547, the NEC, accredited testing laboratories such as Underwriters Laboratories, and the manufacturer's suggested practices for safe, efficient, and reliable operation of the generating facility in parallel with Company's electric system. Customer shall bear full responsibility for the installation, maintenance, and safe operation of the generating facility. Upon reasonable request from the Company, customer shall demonstrate generating facility compliance.

3. The generating facility shall comply with, and the customer shall represent and warrant its compliance with: (a) any applicable safety and power quality standards established by the Institute of Electrical and Electronics Engineers (IEEE) and accredited testing laboratories such as Underwriters Laboratories (UL); (b) the National Electrical Code (NEC) as may be revised from time to time; (c) Company's rules, regulations, and Company's Terms and Conditions of Service as contained in Company's Retail Electric Tariff as may be revised from time to time with the approval of the Kentucky Public Service Commission (Commission); (d) the rules and regulations of the Commission, as such rules and regulations may be revised from time to time by the Commission; and (e) all other applicable local, state, and federal codes and laws, as the same may be in effect from time to time. Where required by law, customer shall pass an electrical inspection of the generating facility by a local authority having jurisdiction over the installation.

4. Any changes or additions to the Company's system required to accommodate the generating facility shall be considered excess facilities. Customer shall agree to pay Company for actual costs incurred for all such excess facilities prior to construction.

5. Customer shall operate the generating facility in such a manner as not to cause undue fluctuations in voltage, intermittent load characteristics, or otherwise interfere with the operation of Company's electric system. At all times when the generating facility is being operated in parallel with Company's electric system, customer shall so operate the generating facility in such a manner that no adverse impacts will be produced thereby to the service quality rendered by Company to any of its other customers or to any electric system interconnected with Company's electric system. Customer shall agree that the interconnection and operation of the generating facility is secondary to, and shall not interfere with, Company's ability to meet its primary responsibility of furnishing reasonably adequate service to its customers.

Continued on Sheet 19-17

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

6. Customer shall be responsible for protecting, at Customer's sole cost and expense, the generating facility from any condition or disturbance on Company's electric system, including, but not limited to, voltage sags or swells, system faults, outages, loss of a single phase of supply, equipment failures, and lightning or switching surges, except that the Company shall be responsible for repair of damage caused to the generating facility resulting solely from the negligence or willful misconduct on the part of the Company.

7. After initial installation, Company shall have the right to inspect and/or witness commissioning tests, as specified in the Level 1 or Level 2 Application and approval process. Following the initial testing and inspection of the generating facility and upon reasonable advance notice to customer, Company shall have access at reasonable times to the generating facility to perform reasonable on- site inspections to verify that the installation, maintenance and operation of the generating facility comply with the requirements of this tariff.

8. For Level 2 generating facilities, where required by the Company, an eligible customer shall furnish and install on customer's side of the point of common coupling a safety disconnect switch which shall be capable of fully disconnecting the customer's energy generating equipment from Company’s electric service under the full rated conditions of the customer's generating facility. The external disconnect switch (EDS) shall be located adjacent to Company's meters or the location of the EDS shall be noted by placing a sticker on the meter, and shall be of the visible break type in a metal enclosure which can be secured by a padlock. If the EDS is not located directly adjacent to the meter, the customer shall be responsible for ensuring the location of the EDS is properly and legibly identified for so long as the generating facility is operational. The disconnect switch shall be accessible to Company personnel at all times. The Company may waive the requirement for an EDS for a generating facility at its sole discretion, and on a case-by-case basis, upon review of the generating facility operating parameters and if permitted under the Company’s safety and operating protocols.

   The Company shall establish a training protocol for line workers on the location and use of the EDS, and shall require that the EDS
   be used when appropriate, and that the switch be turned back on once the disconnection is no longer necessary.

9. Company shall have the right and authority at Company's sole discretion to isolate the generating facility or require the customer to discontinue operation of the generating facility if Company believes that: (a) continued interconnection and parallel operation of the generating facility with Company's electric system creates or contributes (or may create or contribute) to a system emergency on either Company's or customer's electric system; (b) the generating facility is not in compliance with the requirements of this tariff, and the noncompliance adversely affects the safety, reliability or power quality of Company's electric system; or (c) the generating facility interferes with the operation of Company's electric system. In non-emergency situations, Company shall give customer notice of noncompliance including a description of the specific noncompliance condition and allow customer a reasonable time to cure the noncompliance prior to isolating the generating facilities. In emergency situations, when the Company is unable to immediately isolate or cause the customer to isolate only the generating facility, the Company may isolate the customer's entire facility.

Continued on Sheet 19-18

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

10. Customer shall agree that, without the prior written permission from Company, no changes shall be made to the generating facility as initially approved. Increases in generating facility capacity will require a new "Application for Interconnection and Net Metering" which will be evaluated on the same basis as any other new application. Repair and replacement of existing generating facility components with like components not resulting in increases in generating facility capacity are allowed without approval.

11. To the extent permitted by law, the customer shall protect, indemnify, and hold harmless the Company and its directors, officers, employees, agents, representatives and contractors against and from all loss, claims, actions or suits, including costs and attorneys fees, for or on account of any injury or death of persons or damage to property caused by the customer or the customer's employees, agents, representatives and contractors in tampering with, repairing, maintaining or operating the customer's generating facility or any related equipment or any facilities owned by the Company except where such injury, death or damage was caused or contributed to by the fault or negligence of the Company or its employees, agents, representatives, or contractors.

    The liability of the Company to the customer for injury to person and property shall be governed by the tariff(s) for the class of service under which the customer is taking service.

12. The customer shall maintain general liability insurance coverage (through a standard homeowner's, commercial, or other policy). Customer shall provide Company with proof of such insurance at the time that application is made for net metering.

13. By entering into an Interconnection Agreement, or by inspection, if any, or by non-rejection, or by approval, or in any other way, Company does not give any warranty, express or implied, as to the adequacy, safety, compliance with applicable codes or requirements, or as to any other characteristics, of the generating facility equipment, controls, and protective relays and equipment.

14. Customer's generating facility is transferable to other persons or service locations only after notification to the Company has been made and verification that the installation is in compliance with this tariff. Upon written notification that an approved generating facility is being transferred to another person, customer, or location, the Company will verify that the installation is in compliance with this tariff and provide written notification to the customer(s) within 20 business days. If the installation is no longer in compliance with this tariff, the Company will notify the customer in writing and list what must be done to place the facility in compliance.

15. The customer shall retain any and all Renewable Energy Credits (RECs) that may be generated by their generating facility.

Continued on Sheet 19-19

Tariff N.M.S. II Continued
(Net Metering Service II)

TERMS AND CONDITIONS FOR LEVEL 2, continued

Effective Term and Termination Rights

This Agreement becomes effective when executed by both parties and shall continue in effect until terminated. This Agreement may be terminated as follows: (a) Customer may terminate this Agreement at any time by giving the Company at least sixty (60) days' written notice; (b) Company may terminate upon failure by the Customer to continue ongoing operation of the generating facility; (c) either party may terminate by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of the Agreement or the Rules or any rate schedule, tariff, regulation, contract, or policy of the Company, so long as the notice specifies the basis for termination and there is opportunity to cure the default; (d) the Company may terminate by giving the Customer at least thirty (30) days notice in the event that there is a material change in an applicable law, regulation or statute affecting this Agreement or which renders the system out of compliance with the new law or statute.

IN WITNESS WHEREOF, the Parties have executed this Agreement, effective as of the date first above written.

Customer Signature: ______________________________ **Date:** ______________

Printed Name: ______________________________ **Title:** ______________

Company Signature: ______________________________ **Date:** ______________

Printed Name: ______________________________ **Title:** ______________

Continued on Sheet 19-20

Tariff N.M.S. II Continued
(Net Metering Service II)

Interconnection Agreement – Level 2
Exhibit A

- Exhibit A will contain additional detailed information about the Generating Facility such as a single line diagram, relay settings, and a description of operation.

- When construction of the Company's facilities is required, Exhibit A will also contain a description and associated cost.

- Exhibit A will also specify requirements for a Company inspection and witness test and when limited operation for testing or full operation may begin.

Tariff COGEN/SPP I
(Cogeneration and/or Small Power Production--100 KW or Less)

Availability of Service
This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of 100 KW or less. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

Monthly Charges for Delivery from the Company to the Customer
Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers with cogeneration and/or small power production facilities having a total design capacity of more than 10 KW shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

Additional Charges
There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge
The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable

Option 2 & 3 - Where meters are used to measure the excess or total energy and average on-peak capacity purchased by the Company:

	Single Phase	Polyphase
Standard Measurement	$9.25	$12.10
T.O.D. Measurement	$9.85	$12.40

Continued on Sheet 20-2

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Tariff COGEN/SPP I Continued
(Cogeneration and/or Small Power Production--100 KW or Less)

Additional Charges Continued

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each use.

Local Facilities Charge
Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

Monthly Credits or Payments for Energy and Capacity Deliveries

Energy Credit
The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter – All KWH	Variable LMP at time of delivery ¢ KWH
T.O.D. Meter	
On-Peak KWH	Variable LMP at time of delivery ¢ KWH
Off-Peak KWH	Variable LMP at time of delivery ¢ KWH

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. 2023~~0~~/2024~~1~~ $3~~2~~.48~~81~~ kW/month
2024~~1~~/2025~~2~~ $3~~3~~.72~~37~~ kW/month
2025~~2~~/2026~~3~~ $3.25~~9~~ kW/month, times the lowest of:

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

Continued on Sheet 20-3

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Tariff COGEN/SPP I Continued
(Cogeneration and/or Small Power Production--100 KW or Less)

Monthly Credits or Payments for Energy and Capacity Deliveries Continued

If T.O.D. energy meters are used,

B. 2023~~0~~/2024~~1~~ $8~~6~~.36~~74~~ kW/month
2024~~1~~/2025~~2~~ $8~~8~~.92~~09~~ kW/month
202~~2~~5/2026~~3~~ $7.79~~89~~ kW/month, times the lowest of:

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305 or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

On-Peak and Off-Peak Periods
The on-peak period shall be defined as starting at 7:00A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00A.M. local time, Monday through Friday, and all hours of Saturday and Sunday.

Charges for Cancellation or Non Performance Contract
If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/SPP I or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

Term of Contract
Contracts under this tariff shall be made for a term not less than five (5) years. A Qualifying Facility can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established.

Tariff COGEN/SPP II
(Cogeneration and/or Small Power Production--Over 100 KW)

Availability of Service
This tariff is available to customers with cogeneration and/or small power production (COGEN/SPP) facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978, and which have a net power production capacity of over 100 KW. In addition, cogeneration facilities must have a net power production capacity at or below 20,000 KW, and small power production facilities must have a net power production capacity at or below 5,000 KW. Such facilities shall be designed to operate properly in parallel with the Company's system without adversely affecting the operation of equipment and services of the Company and its customers, and without presenting safety hazards to the Company and customer personnel.

The customer has the following options under this tariff, which will affect the determination of energy and capacity and the monthly metering charges:

Option 1 - The customer does not sell any energy or capacity to the Company, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 2 - The customer sells to the Company the energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities in excess of the customer's total load, and purchases from the Company its net load requirements, as determined by appropriate meters located at one delivery point.

Option 3 - The customer sells to the Company the total energy and average on-peak capacity produced by the customer's qualifying COGEN/SPP facilities, while simultaneously purchasing from the Company its total load requirements, as determined by appropriate meters located at one delivery point.

Monthly Charges for Delivery from the Company to the Customer
Such charges for energy, and demand where applicable, to serve the customer's net or total load shall be determined according to the tariff appropriate for the customer, except that Option 1 and Option 2 customers shall be served under demand-metered tariffs, and except that the monthly billing demand under such tariffs shall be the highest determined for the current and previous two billing periods. The above three-month billing demand provision shall not apply under Option 3.

Additional Charges
There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge
The additional monthly charge for special metering facilities shall be as follows:

Option 1 - Not Applicable

Option 2 & 3 - Where meters are used to measure the excess or total energy and average on peak capacity purchased by the Company:

	Single Phase	Polyphase
Standard Measurement	$9.25	$12.10
T.O.D. Measurement	$9.85	$12.40

Continued on Sheet 21-2

Tariff COGEN/SPP II Continued
(Cogeneration and/or Small Power Production-- Over 100 KW)

Additional Charges Continued

Under Option 3, when metering voltage for COGEN/SPP facilities is the same as the Company's delivery voltage, the customer shall, at his option, either route the COGEN/SPP totalized output leads through the metering point, or make available at the metering point for the use of the Company and, as specified by the Company, metering current leads which will enable the Company to measure adequately the total electrical energy and average capacity produced by the qualifying COGEN/SPP facilities, as well as to measure the electrical energy consumption and capacity requirements of the customer's total load. When metering voltage for COGEN/SPP facilities is different from the Company's delivery voltage, metering requirements and charges shall be determined specifically for each case.

Local Facilities Charge
Additional charges to cover "interconnection costs" incurred by the Company shall be determined by the Company for each case and collected from the customer. For Options 2 and 3, the cost of metering facilities shall be covered by the Monthly Metering Charge and shall not be included in the Local Facilities Charge. The customer shall make a one-time payment for the Local Facilities Charge at the time of installation of the required additional facilities, or, at his option, up to 12 consecutive equal monthly payments reflecting an annual interest charge as determined by the Company, but not to exceed the cost of the Company's most recent issue of long-term debt. If the customer elects the installment payment option, the Company may require a reasonable security deposit.

Monthly Credits or Payments for Energy and Capacity Deliveries

Energy Credit
The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter – All KWH	Variable LMP at time of delivery ¢ KWH
T.O.D. Meter	
On-Peak KWH	Variable LMP at time of delivery ¢ KWH
Off-Peak KWH	Variable LMP at time of delivery ¢ KWH

Capacity Credit
If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. 2023~~0~~/2024~~1~~ $~~2~~3.48~~81~~ kW/month
2024~~1~~/2025~~2~~ $3.72~~37~~ kW/month
2025~~2~~/2026~~3~~ $3.25~~9~~ kW/month, times the lowest of:

1. monthly contract capacity, or
2. current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730,or
3. lowest average capacity metered during the previous two months if less than monthly contract capacity.

Continued on Sheet 21-3

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Tariff COGEN/SPP II Continued
(Cogeneration and/or Small Power Production-- Over 100 KW)

Monthly Credits or Payments for Energy and Capacity Deliveries Continued

If T.O.D. energy meters are used,

B. 2023~~0~~/2024~~1~~ $8~~6~~.36~~74~~ kW/month
2024~~1~~/2025~~2~~ $8.92~~09~~ kW/month
2025~~2~~/2026~~3~~ $7.79~~89~~ kW/month, times the lowest of:

1. on-peak contract capacity, or
2. current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by 305, or
3. lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

On-Peak and Off-Peak Periods
The on-peak period shall be defined as starting at 7:00 A.M. and ending at 9:00 P.M., local time, Monday through Friday.

The off-peak period shall be defined as starting at 9:00 P.M. and ending at 7:00 A.M., local time, Monday through Friday, and all hours of Saturday and Sunday.

Charges for Cancellation or Non Performance Contract
If the customer should, for a period in excess of six months, discontinue or substantially reduce for any reason the operation of cogeneration and/or small power production facilities which were the basis for the monthly contract capacity or the on-peak contract capacity, the customer shall be liable to the Company for an amount equal to the total difference between the actual payments for capacity paid to the customer and the payments for capacity that would have been paid to the customer pursuant to this Tariff COGEN/ SPP II or any successor tariff. The Company shall be entitled to interest on such amount at the rate of the Company's most recent issue of long-term debt at the effective date of the contract.

Term of Contract
Contracts under this tariff shall be made for a term not less than five (5) years. A Qualifying Facility can request that avoided cost rates be set on an "as available" basis or when a legally enforceable obligation is established.

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Tariff C.S.-I.R.P.
(Contract Service – Interruptible Power)

Availability of Service
Available for service to customers who contract for service under the Company's Industrial General Service (I.G.S.) tariff. The Company reserves the right to limit the total contract capacity for all customers served under this Tariff to 75,000 kW.

Loads of new customers locating within the Company's service area or load expansions by existing customers may be offered interruptible service as part of an economic development incentive. Such interruptible service shall not be counted toward the limitation on total interruptible power contract capacity, as specified above, and will not result in a change to the limitation on total interruptible power contract capacity.

Conditions of Service
The Company will offer eligible customers the option to receive interruptible power service. This interruptible service will be consistent with PJM's Load Management Resource Product – Capacity Performance Demand Response requirement, hereafter referred to as the "PJM Demand Response Program", subject to any limitations on the availability of that Program by PJM. To be eligible for the credit, customers must be able to provide interruptible load (not including behind the meter diesel generation) of at least one (1) MW at a single site and commit to a minimum four (4) year contract term. The contract shall provide that 90 days prior to each contract anniversary date, the customer shall re-nominate the amount of interruptible load for the upcoming contract year, except that the cumulative reductions over the life of the contract shall not exceed 20% of the original interruptible load nominated under the contract. If no re-nomination is received at least 90 days prior to the contract anniversary date, the prior year's interruptible load shall apply for the forthcoming contract year.

Upon receipt of a request from the Customer for interruptible service, the Company will provide the Customer with a written addendum containing the rates and related terms and conditions of service under which such service will be provided by the Company. If the parties reach an agreement based upon the offer provided to the Customer by the Company, such written contract will be filed with the Commission. The contract shall provide full disclosure of all rates, terms and conditions of service under this Tariff, and any and all agreements related thereto, subject to the designation of the terms and conditions of the contract as confidential, as set forth herein.

The Customer shall provide reasonable evidence to the Company that the Customer's electric service can be interrupted in accordance with the provisions of the written agreement including, but not limited to, the specific steps to be taken and equipment to be curtailed upon a request for interruption.

The Customer shall contract for capacity sufficient to meet average maximum interruptible power requirements, but in no event will the interruptible amount contracted for be less than 1,000 KW at any delivery point.

The Company reserves the right to test and verify the customer's ability to curtail. Any such test or verification may require actual physical interruption or curtailment, to the extent such testing or interruption is required under PJM's Demand Response Program.

NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.

Except as otherwise provided in the written agreement, the Company's Terms and Conditions of Service shall apply to service under this tariff.

Continued on Sheet 22-2

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Tariff C.S.-I.R.P. Continued
(Contract Service – Interruptible Power)

Rate
Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's Demand Response Program rules as capacity for the purpose of the Company's Fixed Resource Requirement (FRR) obligation.

Tariff	Tariff Type	Tariff Code Description	Tariff Description
321	IR	CS-IRP SEC	IRP-IGS SECONDARY
330	IR	CS-IRP PR	IRP-IGS PRIMARY
331	IR	CS-IRP ST	IRP-IGS SUBTRANSMISSION
332	IR	CS-IRP TR	IRP-IGS TRANSMISSION

Charges for service under this Tariff will be set forth in the written agreement between the Company and the Customer and will reflect the firm service rates otherwise available to the Customer.

Adjustment Clauses
The bill amount computed at the charges specified above shall be increased or decreased in accordance with the following:

Kentucky Economic Development Surcharge	Sheet No. 27
Demand-Side Management Adjustment Clause	Sheet No. 28
System Sales Clause	Sheet No. 29
Fuel Adjustment Clause	Sheet No. 30
Purchase Power Adjustment	Sheet No. 31
Environmental Surcharge	Sheet No. 32
Decommissioning Rider	Sheet No. 33
Distribution Reliability Rider	Sheet No. 34
Securitization Financing Rider	Sheet No. 35
Federal Tax Change Tariff	Sheet No. 36
City's Franchise Fee	Sheet No. 37
School Tax	Sheet No. 38

~~Fuel Adjustment Clause~~	~~Sheet No. 5~~
~~System Sales Clause~~	~~Sheet No. 19~~
~~Franchise Tariff~~	~~Sheet No. 20~~
~~Demand-Side Management Adjustment Clause~~	~~Sheet No. 22~~
~~Federal Tax Cut Tariff~~	~~Sheet No. 23~~
~~Kentucky Economic Development Surcharge~~	~~Sheet No. 24~~
~~Environmental Surcharge~~	~~Sheet No. 29~~
~~Capacity Charge~~	~~Sheet No. 30~~
~~School Tax~~	~~Sheet No. 33~~
~~Purchase Power Adjustment~~	~~Sheet No. 35~~
~~Decommissioning Rider~~	~~Sheet No. 38~~

~~**Delayed Payment Charge**~~
~~This tariff is due and payable in full on or before the due date stated on the bill. On all accounts not so paid, an additional charge of 5% of the unpaid balance will be made.~~

Confidentiality
All terms and conditions of any written contract under this Tariff shall be protected from disclosure as confidential, proprietary trade secrets, if either the Customer or the Company requests a Commission determination of confidentiality pursuant to 807 KAR 5:001 Section 7 and the request is granted.

Special Terms and Conditions
Except as otherwise provided in the written agreement, this Tariff is subject to the Company's Terms and Conditions of

Service.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customers with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

Rider D.R.S.
(Demand Response Service)

Availability of Service

Available for Demand Response Service ("DRS") to customers that take firm service from the Company under a standard demand-metered rate schedule and that have the ability to curtail load under the provisions of this Schedule. Each customer electing service under this Schedule shall contract, via a Contract Addendum, for a definite amount of firm and interruptible capacity agreed to by the Company and the customer. The interruptible capacity amount shall not exceed the Customer's average on-peak demand for the past 12 months. The Company reserves the right to limit the aggregate amount of interruptible capacity contracted for under this Schedule. The Company will take Customer DRS requests in the order received. Customers taking service under this Schedule shall not participate in any PJM demand response program for Capacity.

Conditions of Service

1. The Company, in its sole discretion, reserves the right to call for curtailments of the Customer's interruptible load at any time. Such interruptions shall be designated as "Discretionary Interruptions" and shall not exceed sixty (60) hours of interruption during any Interruption Year. The "Interruption Year" shall be defined as the consecutive twelve (12) month period commencing on June 1 and ending on May 31. Should this Schedule become effective on a date other than June 1, the period from the effective date of this Schedule until the next May 31 after such effective date shall be referred to as the "Initial Partial Interruption Year." In any Initial Partial Interruption Year, Discretionary Interruptions shall not exceed a number of hours equal to the product of the number of full calendar months during the Initial Partial Interruption Year and the annual interruption hours divided by 12.

2. The monthly Interruptible Demand Credit Rate shall be $5.50/kW-month, credited to participating Customers' bills for standard tariff service.

3. The Company will endeavor to provide the Customer with as much advance notice as possible of a Discretionary Interruption. The Company shall provide notice at least 90 minutes prior to the commencement of a Discretionary Interruption. Such notice shall include both the start and end time of the Discretionary Interruption. For any Discretionary Interruption, the Customer shall be permitted to choose not to interrupt and to continue to operate during the event, provided that the Customer pays the DRS Event Failure Charge. Discretionary Interruptions shall begin and end on the clock hour.

4. Discretionary Interruption events shall be three (3) consecutive hours and there shall not be more than six (6) hours of Discretionary Interruption per day.

5. The Company will inform the Customer regarding the communication process for notices to curtail. The Customer is ultimately responsible for receiving and acting upon a curtailment notification from the Company.

6. The minimum interruptible capacity contracted for under this Schedule will be 500 kW. Customers with multiple electric service accounts at a single location may aggregate those individual accounts to meet the 500 kW minimum interruptible capacity requirement under this Schedule; however, the interruptible capacity committed for each individual account shall not be less than 100 kW.

7. All Customer meter data required under this Schedule shall be determined from 15- or 30-minute integrated metering, as applicable based on the Customer's rate schedule, with remote interrogation capability and demand recording equipment. Such metering equipment shall be owned, installed, operated, and maintained by the Company.

8. **NO RESPONSIBILITY OR LIABILITY OF ANY KIND SHALL ATTACH TO OR BE INCURRED BY THE COMPANY FOR, OR ON ACCOUNT OF, ANY LOSS, COST, EXPENSE, OR DAMAGE CAUSED BY OR RESULTING FROM, EITHER DIRECTLY OR INDIRECTLY, ANY CURTAILMENT OF SERVICE UNDER THE PROVISIONS OF THIS SCHEDULE.**

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Rider D.R.S. Continued
(Demand Response Service)

Interruptible Capacity Reservation

The Customer shall have established a total Capacity Reservation under its Contract for Service under the applicable demand-metered rate schedule. In a Contract Addendum, the Customer shall designate a set amount of kW of that total Capacity Reservation as the Firm Service Capacity Reservation, which is not subject to interruption under this Schedule. The Interruptible Capacity Reservation shall be the Customer's average on-peak demand over the past 12 months in excess of the Firm Service Capacity Reservation.

The Interruptible Capacity Reservation is subject to annual review and adjustment by the Company and the Customer.

Monthly Interruptible Demand Credit

The monthly Interruptible Demand Credit shall be equal to the product of Demand Credit per kW-month and the Customer's Interruptible Capacity Reservation kW.

Interruption Event Compliance

A Customer will be determined to have failed a DRS interruption event if the Customer has not achieved at least ninety (90) percent of their agreed upon interruptible capacity reservation during the duration of a DRS event.

DRS Event Failure

A Customer that fails one or more DRS interruption events shall repay a portion of the Customer's total annual DRS Interruptible Demand Credit per the following table:

Number of Failures	Penalty Payment %
Failure 1	5%
Failure 2	10%
Failure 3	10%
Failure 4	15%
Failure 5	15%
Failure 6	20%
Failure 7	25%
Totals	100%

The DRS Event Failure Charge equals the Customer's Interruptible Capacity Reservation kW, times the DRS Interruptible Demand Credit Rate, times 12, times the corresponding DRS Event Failure Charge Penalty Payment % set forth in the table above. Under no circumstance will a Customer be charged for DRS interruption event failures in an amount greater than the annual amount of DRS Interruptible Demand Credits the Customer would have or has received in an Interruption Year.

Settlement

The net amount of the monthly Interruptible Demand Credit and any DRS Event Failure Charge will be included in the Customer's monthly bill for electric service under its demand-metered rate schedule.

Term

A Contract Addendum term under this Schedule shall be at least one (1) Interruption Year and shall continue for each subsequent Interruption Year until either party provides written notice no later than April 2 of its intention to discontinue service effective June 1 under the terms of this Schedule. Any participating Customer must participate for at least one full Interruption Year, therefore a Customer that begins service under this rider during the Initial Partial Interruption Year must then also participate in the subsequent full Interruption Year.

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In Case No.: 2023-00159 Dated XXXX XX, XXXX

Tariff V.C.S.
(Voluntary Curtailment Service)

This Rider provides the Customer with the opportunity to reduce their cost of electric service by curtailing usage during Voluntary Curtailment Events requested by the Company. Upon each event, the Customer shall have the option, but not the obligation, to curtail usage at their premises and be compensated by the Company as provided below.

Availability of Service
The initial term of this tariff is two (2) years beginning January 28, 2022. Eligible customers must have a curtailable usage of not less than 1,000 kW at the metering point for a single account for electric service, have accounts that are current, and maintain satisfactory credit criteria as defined under the Company's Terms and Conditions under Deposits, Section D. All provisions of the applicable standard tariff for electric service will apply except as modified herein. Customers participating in a third-party demand response program and customers receiving service under special contracts, including COGEN/SPP contracts, are not eligible to participate under this Rider. Customers in this program are also subject to curtailments due to system emergencies in the same manner as all other firm service customers.

Monthly Charges and Credits
Customer's net monthly bill for service provided under this Rider will be calculated in accordance with the Company's applicable rate schedule, with the exception that the Voluntary Curtailment Credit will be applied as a line item on the Customer's bill.

The Voluntary Curtailment Event Hours and the Voluntary Curtailment Price will be quoted to the Customer by no later than 5:00 p.m. ET of the day prior to the Event Day.

The Voluntary Curtailment Price will be based upon the Day-Ahead Market price of energy at the time of the Voluntary Curtailment Event, as determined in the Company's sole judgment, but not less than $100 per MWh. The AEPKY_RESID_AGG LMP shall be used to develop the Voluntary Curtailment Price.

Conditions of Service

1. The Company reserves the right to request a Voluntary Curtailment Event at any time at the Company's sole discretion. The Company will call no more than two (2) Voluntary Curtailment Events per day. The Events must be separated by at least one (1) non-event hour.
2. Customers must request enrollment in the program thirty (30) days before participating in a Voluntary Curtailment Event. A fully executed contract is required before a customer may participate in a Voluntary Curtailment Event.
3. The Company shall notify the Customer of a Voluntary Curtailment Event by e-mail, text or automated phone message. The Customer shall designate their representative(s) to receive said notifications.
4. No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.
5. The Customer shall not receive credit for any curtailment periods in which the Customer's usage is already reduced due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, economic conditions or any event other than the Customer's normal operating conditions.
6. The Customer's participation in any Company capacity-based demand response program takes priority over this program. No credit shall be given under this program for hours that a customer is responsible for curtailing under another program. An interval meter is required for service under this Rider. The incremental cost of any special metering, communications or control equipment required for service under this Rider beyond that normally provided shall be borne by the Customer.

Continued on Sheet 24-2

Tariff V.C.S. Continued
(Voluntary Curtailment Service)

Curtailed Demand
For each Voluntary Curtailment Event, Curtailed Demand shall be defined as the difference between the Customer's Average On-Peak Demand and the maximum sixty (60)-minute integrated demand in kW during the Voluntary Curtailment Event. The Curtailed Demand so computed will not be less than zero (0).

The Company shall determine the Customer's Average On-Peak Demand in kW specified in a contract or contract addendum for service under this Rider. The Customer's Average On-Peak Demand will be reviewed annually. Annual, seasonal or monthly Average On-Peak Demands may be established based upon Customer's historic usage patterns. For the purpose of determining the Average On-Peak Demand, the on-peak period is defined as 7:00 a.m.to 11:00 p.m. ET for all weekdays, Monday through Friday.

Voluntary Curtailment Credit
For each Voluntary Curtailment Event, the Event Credit shall be the product of the Curtailed Demand, the number of Voluntary Curtailment Event Hours and the Voluntary Curtailment Price.

The Voluntary Curtailment Credit will be the sum of the Event Credits for the calendar month.

The Voluntary Curtailment Credit will be applied to the Customer's bill within forty-five (45) days after the end of the month in which the Voluntary Curtailment Event occurred.

The Voluntary Curtailment Credit applied to the Customer's bill for service will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identity of this amount is preserved.

Non-Compliance Provision
There are no charges for non-compliance with a Voluntary Curtailment Event.

Term
Contracts under this Rider shall be made for an initial period of one (1) year and shall remain in effect thereafter until either party provides to the other at least thirty (30) days written notice of its intention to discontinue service under this Rider.

Tariff E.D.R.
(Economic Development Rider)

Availability of Service
To encourage economic development in the Company's service territory, limited-term reductions in billing demand charges described herein are offered to qualifying new and existing retail customers who make application for service under this Rider.

Service under this Economic Development Rider (EDR) is intended for specific types of commercial and industrial customers whose operations, by their nature, will promote sustained economic development based on plant and facilities investment and job creation. Availability is limited to customers on a first-come, first-served basis until such time as a total of 250 MW of new load has been added to Kentucky Power's system under the EDR. The EDR is available to commercial and industrial customers served under Tariffs L.G.S. and I.G.S. who meet the following requirements:

(1) A new customer must have at least a monthly maximum billing demand of 500 kW. An existing customer must increase its monthly maximum billing demand by at least 500 kW over the current Base Maximum Billing Demand in order to receive the Incremental Billing Demand Discount (IBDD).

(2) A new customer, or the business expansion by an existing customer, will receive a Supplemental Billing Demand Discount (SBDD) for creating and sustaining at least 25 new permanent full time jobs over the contract term at the service location. The Company reserves the right to verify job counts. Failure to demonstrate the creation of new employment positions or to maintain the employment during the contract term will result in the termination of the supplemental discount.

(3) The customer must demonstrate to the Company's satisfaction that, absent the availability of this EDR, the qualifying new or increased electrical demand would be located outside of the Company's service territory or would not be placed in service.

Terms and Conditions

(1) The Company will offer the EDR to qualifying customers with new or increased load when the Company has sufficient generating capacity available. When sufficient generating capacity is not available, the Company will procure the additional capacity on the customer's behalf. The cost of capacity procured on behalf of the customer shall reduce on a dollar-for-dollar basis the customer's IBDD and SBDD. Such reduction shall be capped so that the customer's maximum demand charge shall be the non- discounted tariff demand charge. The reduction will be applied in reverse chronological order beginning with the most recent customer to receive discounted service under this tariff. The last customer to sign up for the EDR tariff would be the first customer responsible for paying the cost of incremental capacity purchases. In any year during the discount period in which the customer pays the full tariff demand charge for all twelve months, the Company will reduce the term of the contract by one year.

(2) The new or increased load cannot accelerate the Company's plans for additional generating capacity during the period for which the customer receives a demand discount. Customers receiving Temporary Service are not eligible for this EDR.

(3) To receive service under this EDR, the customer shall make written application to the Company with sufficient information contained therein to determine the customer's eligibility for service. At a minimum, such information must include:

a. A description and good faith estimate of the new or increased load to be served during each year of the contract,
b. The number of new employees or jobs that will be added as a result of the new load,
c. A description of the anticipated capital investment,
d. A description of all other federal, state or local economic development tax incentives, grants, or any other incentives or assistance associated with the new or expanded project, and
e. A statement that without the EDR discount, the customer would locate elsewhere or would choose not to expand within Kentucky Power's service territory.

Continued on Sheet 25-2

Tariff E.D.R. Continued
(Economic Development Rider)

Terms and Conditions Continued

(4) For new and existing customers, billing demands for which reductions will be applicable under this EDR shall be for service at a new service location or expanded production at an existing facility and not merely the result of a change of ownership. Relocation of the delivery point of the Company's service, moving existing equipment from another Company-served location or load transfers from another Company-served location do not qualify as a new service location. Relocating existing facilities from within the Company's service territory shall not disqualify the customer from the IBDD as long as the new relocated facility exceeds the Base Maximum Billing Demand of the previous facility by the minimum required amount.

(5) For existing customers, billing demands for which deductions will be applicable under this EDR shall be the result of an increase in business activity and not merely the result of resumption of normal operations following a force majeure, strike, equipment failure, renovation or refurbishment, or other such abnormal operating condition. In the event that such an occurrence has taken place prior to the date of the application by the customer for service under this EDR, the monthly Base Maximum Billing Demand shall be adjusted as appropriate for this analysis to eliminate the effects of such occurrence.

(6) Service under the EDR will be offered under the applicable Tariff L.G.S. or I.G.S. schedule. An EDR will be filed as a Special Contract and must be approved by the Kentucky Public Service Commission before it can be implemented. The total contract period is equal to twice the number of years for which the customer receives a demand discount. The special contract term will be for two (2), four (4) six (6), eight (8), or ten (10) years only.

(7) The IBDD and the SBDD, if applicable, begin when the customer's new or expanded operations are billed for service under this Rider. Temporary jobs created during the construction of new facilities or the expansion phase of existing operations are not eligible to be counted as permanent jobs for the purposes of this EDR.

(8) If construction of new or expanded local distribution and/or transmission related facilities by the Company is required in order to provide the additional service, the customer may be required to make a contribution-in-aid of construction (CIAC) for the installed cost of such facilities pursuant to the provisions of the Company's Terms and Conditions of Service. The total cost of the CIAC, including gross-up by the effect of applicable taxes, will be recovered over the life of the EDR contract period, with no less than 80% recovered during the period for which the customer receives a demand discount. If the customer breaches the terms of the contract or ends the contract prematurely, any unpaid contribution-in-aid of construction must be paid to the Company, and any EDR discounts provided to the customer must be repaid to the Company. CIAC payment provided under this Rider supersedes other payment provisions only in the Company's Terms and Conditions Sheet 2-5 Section 9.

(9) The L.G.S., and I.G.S. tariffs each contain a monthly minimum billing demand charge provision. The minimum demand charge provision is waived for EDR customers for up to 36 months depending upon the length of the contract. The provision is waived for the first 36 months of a 10 year contract, the first 24 months of an 8 year contract and the first 12 months of a 6 year contract. If during the special contract discount period, the customer's monthly demand falls below the minimum billing demand level for four (4) consecutive months or six (6) months total in a contract year, then the EDR discount will not be applied and the appropriate tariff minimum billing demand charge provision will be in force until the customer achieves the minimum billing demand level. Applicable EDR discounts will be applied to the qualifying incremental maximum billing demand only and will appear as a separate line item on the customer's bill.

Continued on Sheet 25-3

Tariff E.D.R. Continued
(Economic Development Rider)

Determination of Monthly Qualifying Incremental Billing Demand
For the purposes of this Rider, the monthly qualifying incremental billing demand will be calculated in the following manner:

Where the new qualifying incremental demand resides in new facilities (or separate facilities for existing customers), those facilities may be metered on a separate meter according to Tariffs L.G.S., I.G.S., for the current billing period and the incremental billing demand will be calculated based upon that facility's meter readings.

Where the new qualifying incremental demand resides in a customer's existing facility with sufficient service and metering capability to accommodate the business expansion, the qualifying incremental billing demand is equal to demand in excess of the Base Maximum Billing Demand. The Base Maximum Billing Demand for each billing month will be calculated by the Company as the average of the previous three years, corresponding month maximum billing demands, subject to Terms and Conditions Items (3) and (4), and will be agreed to by the customer in advance.

Determination of Incremental Billing Demand Discount
Customers meeting all Availability of Service and Terms and Conditions above may contract for service for a period of up to ten (10) years, with a commensurate discount period of up to five (5) years. The qualifying incremental billing demand charge shall be reduced by 50%, 40%, 30%, 20%, 10% in the order of the Customer's choosing at the time of the contract filing. A sample illustration of an (IBDD) for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced by 50% from the applicable tariff L.G.S. or I.G.S., demand charge;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced by 40% from the applicable tariff L.G.S. or I.G.S., demand charge;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced by 30% from the applicable tariff L.G.S. or I.G.S., demand charge;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced by 20% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced by 10% from the applicable tariff L.G.S. or I.G.S., demand charge, but shall not be less than the applicable tariff rate schedule minimum billing demand; and

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10).

The starting point for the IBDD is dependent upon the length of contract: i.e., an eight (8) year contract will have four (4) years of discount and a maximum annual IBDD of 40% in one year. Similarly, a six (6) year contract will have three (3) years of discount and a maximum annual IBDD of 30% in one year.

Continued on Sheet 25-4

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Tariff E.D.R. Continued
(Economic Development Rider)

Determination of Supplemental Billing Demand Discount
At the Company's discretion, a (SBDD) which is applicable to the monthly incremental billing demand charge is available to customers meeting all Availability of Service and Terms and Conditions above, and that create at least twenty five (25) new permanent job opportunities in the facility and that maintain those job opportunities in each discount year. The amount of additional discount is determined by the actual number of jobs maintained in each year. The order in which the SBDD is applied will follow the same order selected by the Customer for the IBDD contract. A sample illustration of the SBDD for a ten (10) year contract follows:

(a) For the twelve consecutive monthly billings of the first contract year, the qualifying incremental billing demand charge shall be reduced an additional 5% for an increase of at least 50 jobs or 2.5% for an increase of at least 25 jobs;

(b) For the twelve consecutive monthly billings of the second contract year, the qualifying incremental billing demand charge shall be reduced an additional 4.5% for an increase of at least 50 jobs or 2.0% for an increase of at least 25 jobs;

(c) For the twelve consecutive monthly billings of the third contract year, the qualifying incremental billing demand charge shall be reduced an additional 4% for an increase of at least 50 jobs or 1. 5% for an increase of at least 25 jobs;

(d) For the twelve consecutive monthly billings of the fourth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3.5% for an increase of at least 50 jobs or 1. 0% for an increase of at least 25 jobs;

(e) For the twelve consecutive monthly billings of the fifth contract year, the qualifying incremental billing demand charge shall be reduced an additional 3% for an increase of at least 50 jobs or 0.5% for an increase of at least 25 jobs; and

(f) All subsequent monthly billings shall be at the full charges stated in the applicable tariff rate schedule for contract years six (6) through ten (10)

The length of the SBDD shall be identical to the length of the IBDD. The starting point for the discount will be commensurate with the contract length, i.e., an eight (8) year contract will have four (4) years of discount with a maximum SBDD of either 4.5% or 2.0% as appropriate during one year of the contract.

The appropriate discount(s) shall be applicable over a period of up to 60 consecutive billing months as selected by the Customer in 12-month increments at the time of the contract.

Terms of Contract
A contract or agreement addendum for service under this Rider, in addition to service under Tariffs L.G.S. or I.G.S., shall be executed by the Customer and the Company for the time period which includes the start-up period and the multi-year period during which a Total Demand Charge discount is in effect and an equal multi-year period during which the customer agrees to pay the full rates in the applicable Tariff rate schedule.

At a minimum, the contract or agreement addendum shall specify the Base Maximum Billing Demand, the anticipated annual total qualifying demand, the Adjustment Factor and related provisions to be applicable under this Rider, and the effective date for the contract addendum.

The customer may discontinue service under this Rider before the end of the contract or agreement addendum only by reimbursing the Company for any and all demand reductions received under this Rider when billed at the applicable tariff schedule rate.

Special Terms and Conditions
Except as otherwise provided in this Rider, written agreements shall remain subject to all of the provisions of the applicable tariffs. This Rider is subject to the Company's Terms and Conditions of Service.

KENTUCKY POWER COMPANY | P.S.C. KY. NO. 13 ORIGINAL SHEET NO. 26-1
CANCELLING P.S.C. KY. NO. 12 ORIGINAL SHEET NO. 26-1

Tariff R.E.A.
(Residential Energy Assistance)

Proceeds of the charge and matching Company contributions will be used to provide financial assistance to eligible residential customers fix electric bills during peak hearting months (January through April).

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D.2

Rate
$0.4~~3~~0 per month per residential account.

Programs
Participation in the programs below will be determined by the residential customer's local community action agency in accordance with guidelines approved by the Commission and the availability of funds. Customer participation is limited to one program each calendar year.

Home Energy Assistance in Reduced Temperatures (HEART)
Participating low-income residential customers, whose primary source of heat is electric, are eligible to receive an electric bill credit of $115.00 a month for bills rendered in January through April.

Participating low-income residential customers, whose primary source of heat is non-electric, are eligible to receive an electric bill credit of $58.00 a month for bills rendered in January through April.

Temporary Heating Assistance in Winter (THAW)
Participating residential customers, who are experiencing temporary economic hardships, are eligible to receive electric bill credits totaling no more than $175.00 for bills rendered in January through April in any single calendar year.

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Tariff K.E.D.S.
(Kentucky Economic Development Surcharge)

Proceeds of the surcharge and matching Company contributions will be used to fund economic development programs and activities as determined by the Company within the 20 counties comprising Kentucky Power's certified territory.

Applicable
To Tariffs G.S, S.G.S. – T.O.D., M.G.S. – T.O.D., L.G.S., L.G.S. – T.O.D., I.G.S., ~~C.S. – Coal,~~ C.S. – I.R.P., M.W.

Rate
$1.00 per month per commercial account.

Tariff D.S.M.C.
(Demand-Side Management Adjustment Clause)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., ~~C.S. Coal,~~ and M.W.,

Rate

1. The Demand-Side Management (DSM) clause shall provide for periodic adjustment per KWH of sales equal to the DSM costs per KWH by customer sector according to the following formula:

$$\text{(c) Adjustment Factor} \quad = \quad \frac{DSM}{S(c)}$$

   Where DSM is the cost by customer sector of demand-side management programs, net lost revenues, incentives, and any over/under recovery balances; (c) is customer sector; and S is the adjusted KWH sales by customer sector.

2. Demand-Side Management (DSM) costs shall be the most recent forecasted cost plus any over/under recovery balances recorded at the end of the previous period.

   a. Program costs are any costs the Company incurred associated with demand-side management which were approved by the Kentucky Power Company DSM Collaborative. Examples of costs to be included are contract services, allowances, promotion, expenses, evaluation, lease expense, etc. by customer sector.

   b. Net lost revenues are the calculated net lost revenues by customer sector resulting from the implementation of the DSM programs.

   c. Incentives are a shared-savings incentive plan consisting of one of the following elements: The <u>efficiency incentive</u>, which is defined as 15 percent of the estimated net savings associated with the programs. Estimated net savings are calculated based on the California Standard Practice Manual's definition of the Total Resources Cost (TRC) test, or the <u>maximizing incentive</u> which is defined as 5 percent of actual program expenditures if program savings cannot be measured.

   d. Over/ Under recovery balances are the total of the differences between the following:

      i. the actual program costs incurred versus the program costs recovered through DSM adjustment clause, and

      ii. the calculated net lost revenues realized versus the net lost revenues recovered through the DSM adjustment clause, and

      iii. the calculated incentive to be recovered versus the incentive recovered through the DSM adjustment clause.

3. Sales (S) shall be the total ultimate KWH sales by customer sector less non-metered, opt-out and lost revenue impact KWHs by customer sector.

4. The provisions of the Demand-Side Management Adjustment Clause will be effective for the period ending December 31, 2023.

5. The DSM adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

Continued on Sheet 28-2

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Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Rate Continued

6. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

7. The resulting range for each customer sector per KWH during the three-year Experimental Demand-Side Management Plan is as follows:

	Customer Sector		
	Residential	Commercial	Industrial*
DSM(c)	$479,489	$181,893	0
S(c)	1,943,627,965	1,448,924,338	0
Adjustment Factor	$0.000247	$0.000126	0

* The Industrial Sector has been discontinued pursuant to the Commission's Order dated September 28, 1999.

Program Descriptions
The D.S.M.C. program availability, program, rate, and equipment descriptions follow:

Continued on Sheet 28-3

Tariff D.S.M.C. Continued
(Demand-Side Management Adjustment Clause)

Program: TEE – Targeted Energy Efficiency

Availability of Service
Available on a voluntary basis to individual residential customers receiving retail electric service from the Company, who have primary electric heat and use an average of 700 kWh per month. Residential customers without primary electric heating may also be eligible for limited efficiency measures if they have electric water heating and use an average of 700 kWh per month from November through March. To qualify, the household's income cannot exceed the designated poverty guidelines as administered by the local community action agency.

Program Description
The Kentucky Power Targeted Energy Efficiency Program (TEE) provides weatherization and energy efficiency services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. The program funding and service is supplemental to the Weatherization Assistance Programs offered by the local community action agency. This program provides energy saving improvements to an existing home. Program services include residential energy audits, the installation of home weatherization/energy conservation items and customer education on home energy efficiency. The home weatherization/energy conservation measures may include, but not limited to:

- High efficiency lighting
- Domestic hot water pipe insulation
- Water heater insulation wrap (electric DHW only)
- Low flow showerhead
- Low flow faucet aerator
- Air and duct sealing (electric heat only)
- Insulation (electric heat only)
- Efficient windows and doors
- Air source heat pump

Rate
No rate applies for this program.

Equipment
The Kentucky Community Action network of not-for-profit community action agencies will furnish and install, in the customer's presence, the equipment as provided by this program.

Tariff S.S.C.
(System Sales Clause)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., ~~C.S. Coal,~~ M.W., O.L. and S.L.

Rate

1. When the annual net revenues from system sales are above or below the annual base net revenues from system sales, as provided in paragraph 2 below, an additional credit or charge equal to the product of the KWHs and a system sales adjustment factor (A) shall be made, where "A", calculated to the nearest 0.0001 mill per kilowatt-hour, is defined as set forth below.

   Annual System Sales Adjustment Factor (A) = (1.0 [Ta –Tb+U/a])/Sa

   In the above formula "T" is Kentucky Power Company's (KPCo) annual net revenues from system sales in the current annual (a), base (b) periods, and "S" is the KWH sales in the current annual (a) period, all defined below. "U/a" represents any under-or-over recovery from the prior period.

   The applicable rate for service rendered on and after September 28, 2021, calculated in accordance with the above formula, is $(.00066) per kWh.

2. The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

   a. KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.

   b. KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

      The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

   c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

3. The base annual net revenues from system sales are: $ 1,935,350~~7,326,879~~

4. Sales (S) shall be equated to the sum of (a) generation (including energy produced by generating plant during the construction period), (b) purchase, and (c) interchange-in, less (d) energy associated with pumped storage operations, less (e) inter-system sales and less (f) total system losses.

5. The system sales adjustment factor shall be based upon actual annual revenues and costs for system sales, subject to subsequent adjustment upon final determination of actual revenues and costs.

6. The annual System Sales Clause shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle. The Company shall update the Annual System Sales Adjustment Factor for the period ending June 30, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

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Tariff F.A.C.
(Fuel Adjustment Clause)

Applicable

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, R.S.D., G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., ~~C.S. Coal,~~ M.W., O.L., and S.L.

Rate

1. The fuel clause shall provide for periodic adjustment per kWh of sales equal to the difference between the fuel costs per kWh of sales in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below:

2. F(b)/S(b) shall be so determined that on the effective date of the Commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero (0).

3. Fuel costs (F) shall be the most recent actual monthly cost of:

   a. Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of the fuel related substitute generation, plus

   b. The actual identifiable fossil and nuclear fuel costs [if not known--the month used to calculate fuel (F), shall be deemed to be the same as the actual unit cost of the Company generation in the month said calculations are made. When actual costs become known, the difference, if any, between fuel costs (F) as calculated using such actual unit costs and the fuel costs (F) used in that month shall be accounted for in the current month's calculation of fuel costs (F)] associated with energy purchased for reasons other than identified in paragraph (c) below, but excluding the cost of fuel related to purchases to substitute the forced outages, plus

   c. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases, the charges as a result of scheduled outage, and other charges for energy being purchased by the Company to substitute for its own higher cost of energy; and less

   d. The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

   e. The fuel-related costs charged to the Company by PJM Interconnection LLC those costs identified in the following Billing Line Items, as may be amended from time to time by PJM Interconnection LLC: Billing Line Items 1210, 2210, 1215, 1218, 2217, 2218, 1230, 1250, 1260, 2260, 1370, 2370, 1375, 2375, 1400, 1410, 1420, 1430, 1478, 1340, 2340, 1460, 1350, 2350, 1360, 2360, 1470, 1377, 2377, 1480, 1378, 2378, 1490, 1500, 2420, 2220, 1200, 1205, 1220, 1225, 2500, 2510, 1930, 2211, 2215, 2415 and 2930.

   f. All fuel costs shall be based on weighted average inventory costing.

   ~~f.~~g. All Commission approved financial power hedging program-related contract settlements, and related contract costs.

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Tariff F.A.C. Continued
(Fuel Adjustment Clause)

Rate Continued

4. Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the Commission, include the fuel costs of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel costs (F) in subsection (3)(a) and (b) above, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

5. Sales (S) shall be all kWh's sold, excluding intersystem sales. If, for any reason billed system sales cannot be coordinated with the fuel costs for the billing period, sales may be equated to: (i) generation, plus (ii) purchases, plus (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) intersystem sales referred to in subsection (3)(d) above, less (vi) total system losses. Utility used energy shall not be excluded in the determination of sales (S).

6. The cost of fossil fuel shall only include the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees, less any cash or other discounts.

7. At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the Commission and all other agreements, options, amendments, modifications, and similar documents related to the procurement of fuel supply or purchased power. Any changes in the contracts or other documents, including price escalations, and any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. If fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges, which are unreasonable, shall be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges. The Commission on its own motion may investigate any aspect of fuel purchasing activities covered by 807 KAR 5:056 (Fuel Adjustment Clause).

8. The monthly fuel adjustment shall be filed with the Commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment.

9. Copies of all documents required to be filed with the Commission under 807 KAR 5:056 shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

10. At six (6) month intervals, the Commission shall conduct a formal review and may conduct public hearings on a utility's past fuel adjustments. The Commission shall order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments the Commission finds unjustified due to improper calculation or application of the charge or improper fuel procurement practice.

11. Every two (2) years following the initial effective date of each utility's fuel clause, the Commission shall conduct a formal review and evaluate past operations of the clause, disallow improper expenses, and to the extent appropriate, reestablish the fuel clause charge in accordance with Section 1 (2) of 807 KAR 5:056.

12. The Commission may conduct a public hearing if the Commission finds that a hearing is necessary for the protection of a substantial interest or is in the public interest.

13. Resulting cost per kilowatt-hour in February 2020 to be used as the base cost in Standard Fuel Adjustment Clause is:

Fuel	February 2020	÷	$12,810,858	=	$0.02612/kWh
Sales	February 2020		490,482,730		

This, as used in the Fuel Adjustment Clause, is 2.612¢ per kilowatt-hour.

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~~**Tariff F.A.C. Continued**~~
~~**(Fuel Adjustment Clause)**~~

~~14. Kentucky Power will temporarily reduce the FAC rate from 0.03466 to 0.03226, which will be applied to customer bills rendered between June 29, 2022 and July 28, 2022. This rate reduction reflects Company's election to collect t $2,000,000 of the remaining $3,000,000 of postponed February 2022 and March 2022 estimated costs, which otherwise would have been collected from customers during the July 2022 billing month. The rate reduction described in this paragraph will only be effective for and applied to customer bills rendered between June 29, 2022 and July 28, 2022. More information about the Company's requests to temporarily levelize fuel costs for customers, including its pending request to amortize and collect the remainder of postponed costs in the August 2022 billing cycle, can be found in the Company's Application filed in Case No. 2022-00125.~~

Tariff P.P.A.
(Purchase Power Adjustment)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., ~~C.S. Coal,~~ M.W., O.L. and S.L.

Rate
The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

PPANC = N+CSIRP~~+OATT~~+RKP+RP-BPP

Where:

BPP = The annual amount of purchase power costs included in base rates, $6,554,678~~98,165,699~~.

a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements and purchased power expense from avoided cost payments to net metering customers under tariff N.M.S.II~~.~~above or below the $1,269,331 included in BPP.~~-~~ All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
b. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P., Tariff D.R.S., Tariff V.C.S. and special contracts for interruptible service above or below the $1,165,983~~454,997~~ included in BPP.
~~c. OATT = 100% The net annual PJM load-serving entity Open Access Transmission Tariff Charges above or below the $96,896,495 included in BPP, less the transmission return difference pursuant to the Commission approved Settlement agreement in Case No. 2017-00179.~~
~~d.~~c. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:
    ~~1. Increase in Rockport collection resulting from reduction in base rate deferral;~~
    ~~2.~~1. Rockport deferral amount to be recovered;
    ~~3. Rockport fixed cost savings; and~~
    ~~4.~~2. Rockport offset estimate and true-up.
    ~~5.~~3. Final (over)/under recovery associated with tariff CC following its expiration
~~e.~~d. RP = The cost of fuel related to substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages above or below the $4,119,364~~814,208~~ included in BPP.

Continued on Sheet 31-2

Tariff P.P.A. Continued
(Purchase Power Adjustment)

Rates

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00353	--
S.G.S.-T.O.D.	$0.00288	--
M.G.S.-T.O.D.	$0.00288	--
G.S.	$0.00288	--
L.G.S., L.G.S.-T.O.D.	$0.00014	$0.82
L.G.S.-L.M.-T.O.D.	$0.00265	--
I.G.S. and C.S.-I.R.P.	$0.00014	$1.04
M.W.	$0.00199	--
O.L.	$0.00051	--
S.L.	$0.00051	--

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class} / CP_{Total})}{BD_{Class}}$$

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Tariff P.P.A. Continued
(Purchase Power Adjustment)

Rates Continued

Where:

1. “PPA(D)” is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.

2. “PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.

3. “BE $_{Class}$” is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.

4. “BD $_{Class}$” is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. “CP $_{Class}$” is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.022970~~428~~%	
S.G.S.-T.O.D.		0.018187~~962~~%	
M.G.S.-T.O.D.		0.018187~~962~~%	
G.S.		0.018187~~962~~%	
L.G.S., L.G.S.-T.O.D.		0.016146~~798~~%	
L.G.S.-L.M.-T.O.D.		0.016146~~798~~%	
I.G.S. and C.S.-I.R.P.		0.011832~~232~~%	
M.W.		0.012350~~326~~%	
O.L.		0.005294~~263~~%	
S.L.		0.005375~~262~~%	

6. “BE $_{Total}$” is the sum of the BE Class for all tariff classes.

7. “CP $_{Total}$” is the sum of the CP Class for all tariff classes.

8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.40~~1~~% and the KPSC Maintenance Fee of 0.1493~~956~~% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment Rider revenues.

9. The annual PPA factors shall be filed with the Commission by August 15 of each year, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

   Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

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Tariff E.S.
(Environmental Surcharge)

Applicable
To Tariffs R.S., R.S.D.,R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., ~~C.S. Coal,~~ M.W., O.L., and S.L.

Rate
The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 2 below and in the current period as provided in Paragraph 3 below.

The retail share of the revenue requirement will be allocated between residential and non-residential retail customers based upon their respective total revenues during the previous calendar year. The Environmental Surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

The revenues to which the residential Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax ~~Cut~~Change, Residential Energy Assistance,~~ Capacity Charge, and~~ Purchase Power Adjustment, and Distribution Reliability Rider.

The revenues to which the all other customer Environmental Surcharge factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax ~~Cut~~Change, Kentucky Economic Development Surcharge, ~~Capacity Charge, and~~ Purchase Power Adjustment, and Distribution Reliability Rider.

1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

Where:	E(m)	=	CRR-BRR
	CRR	=	Current Period Revenue Requirement for the Expense Month.
	BRR	=	Base Period Revenue Requirement.

2. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month		Base Net Environmental Costs
January	$	3,022,418~~503,207~~
February		2,558,332~~3,961,295~~
March		2,621,611~~3,695,547~~
April		2,519,828~~4,652,708~~
May		2,514,284~~4,476,891~~
June		2,644,974~~3,896,996~~
July		2,594,563~~4,132,198~~
August		2,741,097~~3,932,695~~
September		2,508,995~~3,687,618~~
October		2,376,639~~3,775,108~~
November		2,423,992~~3,816,807~~
December	$	2,597,739~~3,814,390~~
	$	31,124,472~~47,345,460~~

In accordance with the Stipulation and Settlement Agreement approved by the Commission by its Order dated October 7, 2013 in Case No. 2012-00578, the Mitchell FGD and all related associated costs are not included in base rates or the Base Revenue Requirement but will be included in the Current Period Revenue Requirement. The Mitchell FGD will be excluded from Base Rates at least until June 30, 2020.

Continued on Sheet 32-2

KENTUCKY POWER COMPANY P.S.C. KY. NO. 13 ORIGINAL SHEET NO. 32-2
CANCELLING P.S.C. KY. NO. 12 ORIGINAL SHEET NO. 32-2

Tariff E.S. Continued
(Environmental Surcharge)

3. Current Period Revenue Requirement, CRR
CRR=[((RB $_{KP(c)}$)(ROR $_{KP(c)}$)/12) + OE $_{KP(c)}$ ~~+ [((RB $_{IM(c)}$) (ROR$_{IM(c)}$)/12) + OE$_{IM(c)}$] (.15)~~ – AS]

Where:

RB $_{KP(c)}$ = Environmental Compliance Rate Base for Mitchell.

ROR $_{KP(c)}$ = Annual Rate of Return on Mitchell Environmental Compliance Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.

OE $_{KP(c)}$ = Monthly Pollution Control Operating Expenses for Mitchell.

~~RB $_{IM(c)}$ = Environmental Compliance Rate Base for Rockport.~~

~~ROR $_{IM(c)}$ = Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.~~

~~OE $_{IM(c)}$ = Monthly Pollution Control Operating Expenses for Rockport.~~

AS = Net proceeds from the sale of Title IV and CSAPR SO 2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt.

"KP(C)" identifies components from Mitchell Units – Current Period.~~, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period.~~

The Environmental Compliance Rate Base for ~~both~~ Kentucky Power ~~and Rockport~~ reflects the current cost associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan. The Environmental Compliance Rate Base for Kentucky Power should also include construction work in progress until assets are placed in service. The Operating Expenses for ~~both~~ Kentucky Power ~~and Rockport~~ reflects the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, the 2007 Plan, the 2015 Plan, the 2017 Plan, the 2019 Plan, and the 2021 Plan.

The Rate of Return for Kentucky Power is 9.9~~1~~0% rate of return on equity as authorized by the Commission in its Order Dated ~~January 13, 2021~~XXXX XX, 20XX, Case No. 2023~~0~~-00159~~74~~.

~~The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.~~

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

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Tariff E.S. Continued
(Environmental Surcharge)

4. Revenue Allocation

$$\text{Residential Allocation RA(m)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(m) = the expense month.
(b) = the most recent calendar year revenues

5. Environmental Surcharge Factor

$$\text{Residential Monthly Environmental Surcharge Factor} \quad \frac{\text{Net KY Retail E(m)} \;*\; \text{RA(m)}}{\text{KY RR(m)}}$$

$$\text{All Other Monthly Environmental Surcharge Factor} \quad \frac{\text{Net KY Retail E(m)} \;*\; \text{AO(m)}}{\text{KY OR(m)- KY OF(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

RR(m) = Average Kentucky Residential Retail Revenues for the Preceding Twelve Month Period

OR(m) = Average Kentucky All Other Classes Retail Revenues for the Preceding Twelve Month Period

OF(m) = Average Kentucky All Other Classes Fuel Revenues for the Preceding Twelve Month Period.

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Tariff E.S. Continued
(Environmental Surcharge)

6. Environmental costs "E" shall be the Company's costs of compliance with the Clean Air Act and those environmental requirements that apply to coal combustion wastes and by-products, as follows:

Total Company:

- return on Title IV and CSAPR SO_2 allowance inventory
- over/under recovery balances between the actual costs incurred less the amount collected through the environmental surcharge
- costs associated with any Commission's consultant approved by the Commission
- costs associated with the consumption of Title IV and CSAPR SO_2 allowances
- costs associated with the consumption of NO_x allowances
- return on NO_x allowance inventory
- costs associated with maintaining approved pollution control equipment including material and contract labor (excluding plant labor)
- costs associated with consumables used in conjunction with approved environmental projects.
- return on inventories of consumables used in conjunction with approved environmental projects.
- return on environmental compliance rate base including construction work in progress.
- Monthly expense to amortize the $1,446,998.35 regulatory asset for prudently incurred ELG (Effluent Limitation Guidelines) project costs over a two-year period to begin with July 2022 billing and conclude with June 2024 billing.

~~The Company's share of costs associated with the following environmental equipment at the Rockport Plant:~~

- ~~Continuous Emissions Monitors~~
- ~~Air Emission Fees~~
- ~~Costs Associated with the Rockport Unit Power Agreement~~
- ~~Activated Carbon Injection~~
- ~~Mercury Monitoring~~
- ~~Precipitator Modifications~~
- ~~Dry Sorbent Injection~~
- ~~Coal Combustion Waste Landfill~~
- ~~Low NO_x burners, over Fire Air Landfill~~
- ~~Selective Catalytic Reduction Technology~~

The Company's share of costs associated with the following environmental equipment at the Mitchell Plant:

- Mitchell Unit Nos 1 and 2 Water Injection, Low NO_x burners, Low NO_x burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO_3 Mitigation
- Mitchell Plant Common CEMS, Replace Burner Barrier Valves and Gypsum Material Handling Facilities
- Air Emission Fees
- Precipitator Modifications and Upgrades
- Coal Combustion Waste Landfill
- Bottom Ash and Fly Ash Handling
- Mercury Monitoring (MATS)
- Dry Fly Ash Handling Conversion
- Wastewater Ponds (for the Mitchell CCR compliance project) with depreciation expense calculated using a 20 percent depreciation rate approved by the Commission's July 15, 2021 and May 3, 2022 Orders in Case No. 2021-00004.

7. The monthly environmental surcharge shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

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Decommissioning Rider
(D.R.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., ~~C.S. Coal,~~ M.W., O.L., and S.L..

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) as set in the Company's most recent Rate Case carrying cost over a 25 year period beginning with the date rates became effective in Case No. 2014-00396. The term "Retirement Costs" are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

   The applicable rates for service rendered on and after September 28, 2022 to be applied to the revenues described in paragraph 5 of this tariff are:

$$\text{Residential Adjustment Factor} = \frac{\$12{,}203{,}475}{\$260{,}106{,}760} = 4.6917\%$$

$$\text{All Other Classes Adjustment Factor} = \frac{\$14{,}511{,}306}{\$183{,}145{,}514} = 7.9234\%$$

2. The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve month period, ending June 30 according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{ARR(y)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(y)} = \text{ARR(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

   Where:

   (y) = the expense year;
   (b) = Most recent available twelve month period ended June 30.

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Decommissioning Rider Continued

3. The Residential D.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential D.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation NRA(y)}}{\text{Residential Retail Revenue RR(b)}}$$

Where:

Net Annual Residential Allocation NRA(b)	=	Annual Residential Allocation RA(y), net of Over/(Under) Recovery Adjustment;
Residential Retail Revenue RR(b)	=	Annual Retail Revenue for all KY residential classes for the year (b).

4. The All Other Classes D.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes D.R. Adjustment Factor} = \frac{\text{Net Annual All Other Allocation NOA(y)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(b)}}$$

Where:

Net Annual All Other Allocation NOA(y)	=	Annual All Other Allocation OA(y), net of Over/(Under) Recovery Adjustment;
All Other Classes Non-Fuel Retail Revenue ONR(b)	=	Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b).

5. The Revenues to which the residential Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax ~~Cut~~Change, Residential Energy Assistance, ~~Capacity Charge, and~~ Purchase Power Adjustment, and Distribution Reliability Rider.

   The Revenues to which the all other customer Decommissioning Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax ~~Cut~~Change, Kentucky Economic Development Surcharge~~, Capacity Charge, and~~ Purchase Power Adjustment, and Distribution Reliability Rider.

6. The annual Decommissioning Rider adjustments shall be filed with the Commission no later than August 15th of each year before it is scheduled to go into effect on Cycle 1 of the October billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

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DATE EFFECTIVE: January 1, 2024
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TITLE: Vice President, Regulatory & Finance
By Authority of an Order of the Public Service Commission
In Case No.: 2023-00159 Dated XXXX XX, XXXX

Distribution Reliability Rider
(D.R.R.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S. Secondary and Primary, S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S. Secondary and Primary, L.G.S.-T.O.D. Secondary and Primary, I.G.S. Secondary and Primary, C.S. – I.R.P. Secondary and Primary, and M.W.

Rate
The Distribution Reliability Rider will apply to all customers served at secondary and primary voltages excluding customers receiving service under Tariffs O.L. and S.L. The Annual Distribution Reliability Net Costs to be recovered through this rider will be calculated on a per bill basis using the following formula:

1. Annual Distribution Reliability Net Costs (ADRNC)

ADRNC = ERW + ATL + DACRR + ANDSS + ARSHR

Where:

a. ERW = targeted widening of primary distribution circuits.

b. ATL = the cost of constructing primary lines to tie two circuits together to permit electrical load to be transferred.

c. DACRR = the costs of installing automation equipment to allow for the isolation of a fault and reconfiguration of the circuit to close other devices to re-energize the non-impacted areas of original circuit impacted by the initial fault and the recloser devices upgrade from three-phase to single-phase to allow for future DACR implementation, closure via electronics, event recordings and power quality investigations, and more precise coordination with other devices.

d. ANDSS = the costs of new distribution substations in remote areas with associated transmission lines in and out to reduce the number of radial distribution circuits and reduce outage times.

e. ARSHR = the costs of targeted facilities projects to renew and improve cable, conductor, hardware, and equipment to reduce feeder-level outages.

f. Subparts a through e include the capital expenditure and operations and maintenance to support that capital to enhance customer reliability.

2. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2021-00159 dated ________ as filed and approved by the Commission, Kentucky Power Company is to recover from its retail customers the costs associated with the Distribution Reliability Work Plan including vegetation management and other targeted investments to maintain and improve reliability.

Continued on Sheet 34-2

Distribution Reliability Rider Continued
(D.R.R.)

3. The allocation of the ADRNC between residential and all other customers shall be based upon their respective contribution to total non-fuel retail revenues for the most recent twelve-month period, ending December 31 according to the following formula:

$$\text{Residential Allocation}(y) = \frac{\text{KY Residential Retail Revenue RR}(b)}{\text{KY Retail Revenue R}(b)}$$

$$\text{All Other Classes Allocation}(y) = \frac{\text{KY All Other Classes Non-Fuel Retail Revenue OR}(b)}{\text{KY Retail Revenue R}(b)}$$

Where:

(y) = the expense year;
(b) = most recent available twelve month period ended December 31;.
RR = $XXX;
OR = $XXX; and
R = $XXX.

4. The rate will be calculated according to the following formula:

$$\text{Residential Factor} = \frac{\text{Residential Allocation x ADRNC}}{\text{Number of Residential Bills}}$$

$$\text{All Other Classes Factor} = \frac{\text{All Other Classes Allocation x ADRNC}}{\text{Number of All Other Classes Bills}}$$

5. The applicable rates for service rendered on and after _________, calculated in accordance with the above, is:

$$\text{Residential Factor} = \frac{\$XXX}{XXX} = \$X/\text{bill}$$

$$\text{All Other Classes Factor} = \frac{\$XXX}{XXX} = \$X/\text{bill}$$

All Other Classes excludes Tariffs O.L. and S.L. and all customers receiving service at subtransmission and transmission voltage levels.

6. The annual Distribution Reliability Rider adjustments shall be filed with the Commission no later than February 15th of each year before it is scheduled to go into effect Cycle 1 of April billing, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

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7. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Securitization Financing Rider
(S.F.R.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L..

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023-00159, Kentucky Power Company is to recover from retail ratepayers the costs approved for securitization by the Commission.

   This rider is designed to recover from customers the amounts necessary to service, repay and administer customer-backed bonds associated with the approved securitized costs pursuant to the terms of the financing order of the Kentucky Public Service Commission in Case No. 202#-#####.

   This rider shall remain in effect until the complete repayment and retirement of any customer-backed bonds, or refunding bonds, associated with the approved securitized costs. This schedule is irrevocable and nonbypassable for the full term during which it applies.

   The applicable rates for service rendered on and after XXXXXXXXX ##, 202# to be applied to the revenues described in paragraph 5 of this tariff are:

$$\text{Residential Adjustment Factor} = \frac{\$X}{\$X} = X.X\%$$

$$\text{All Other Classes Adjustment Factor} = \frac{\$X}{\$X} = X.X\%$$

2. The allocation of the actual revenue requirement (ARR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent twelve-month period ending December 31 or June 30, according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{ARR(y)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(y)} = \text{ARR(y)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(y) = the expense year;
(b) = Most recent available twelve month period ended December 31 or June 30.

Continued on Sheet 35-2

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KENTUCKY POWER COMPANY P.S.C. KY. NO. 13 ORIGINAL SHEET NO. 35-2
CANCELLING P.S.C. KY. NO. 12 3rd REVISED SHEET NO. 35-2

Securitization Financing Rider Continued
(S.F.R.)

3. The Residential S.F.R. Adjustment shall provide for annual adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential S.F.R. Adjustment Factor} = \frac{\text{Net Annual Residential Allocation NRA(y)}}{\text{Residential Retail Revenue RR(b)}}$$

Where:

Net Annual Residential Allocation NRA(y)	=	Annual Residential Allocation RA(y), net of Over/(Under) Recovery Adjustment;
Residential Retail Revenue RR(b)	=	Annual Retail Revenue for all KY residential classes for the year (b).

~~1.~~4. The All Other Classes S.F.R. Adjustment shall provide for annual adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes S.F.R. Adjustment Factor} = \frac{\text{Net Annual All Other Allocation NOA(y)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(b)}}$$

Where:

Net Annual All Other Allocation NOA(y)	=	Annual All Other Allocation OA(y), net of Over/(Under) Recovery Adjustment;
All Other Classes Non-Fuel Retail Revenue ONR(b)	=	Annual Non-Fuel Retail Revenue for all classes other than residential for the year (b).

5. The Revenues to which the residential Securitization Financing Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Residential Energy Assistance, Purchase Power Adjustment and Distribution Reliability Rider.

   The Revenues to which the all other customer Securitization Financing Rider factor are applied is the sum of the customer's Service Charge, Demand Charge, Energy Charge(s) less Base Fuel, Minimum Charge, Reactive Charge, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Change, Kentucky Economic Development Surcharge, Purchase Power Adjustment and Distribution Reliability Rider.

6. The initial Securitization Financing Rider rates shall be file on the day following the pricing of the bonds and shall become effective the first billing cycle following the closing of the bonds. All subsequent Rider rate adjustments shall be semi-annual (every six months).

   The semi-annual Securitization Financing Rider adjustments shall be filed with the Commission no later than February 15 and August 15th of each year before it is scheduled to go into effect on Cycle 1 of the April and October billing cycles, respectively, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

   Interim Securitization Financing Rider adjustments may be filed with the Commission outside of the standard semi-annual timeframe in order to correct for over- or under-collection to be submitted no later than 10 days before the rate is to be effective.

~~2.~~ Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

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Federal Tax ~~Cut~~ Change Tariff
(F.T.C.)

Applicable
To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., ~~C.S. Coal,~~ M.W., O.L., and S.L.

Rate

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2023~~0~~-001559~~74~~, Kentucky Power Company is to credit to retail ratepayers the approved annual amount of excess accumulated deferred federal income taxes (ADIT) beginning January XX~~14~~, 2024~~1 at the rates set forth below and continue to do so until the Company's base rates are re-set in a future base rate proceeding~~.

2. The Company shall amortize the~~ –~~ calendar year retail Generation and Distribution related ~~ARAM of~~ Protected Excess ADIT of $1,678,164 ~~and the amount of retail Generation and Distribution related Unprotected Excess ADIT needed~~ to support the ~~remainder of the actual calendar year~~ rate credits provided to customers through this ~~rider~~tariff.

3. Beginning with the October 2024 Federal Tax Change Tariff adjustment filing, the actual Corporate Alternative Minimum Tax (CAMT) expense and credits for the prior calendar/tax year shall be included in the Annual Revenue Requirement based on the Company's actual 2023 federal income tax return. This methodology will continue on a year to year basis.

4. For purposes of computing over or under-recovery under this tariff, the Company shall include the actual CAMT expense and the actual CAMT credits at the time that the credits can be used.

5. The Company shall include a final reconciliation of the retail Generation and Distribution related Unprotected Excess ADIT as part of the over or under-recovery computation in the October 2024 Federal Tax Change Tariff adjustment filing.

~~2.~~

~~3.~~6. The applicable rates~~Residential rate credits and All Other rate credits shall be credited to customers~~ on a kWh basis are as follows:

	Residential ($/kWh)	All Other ($/kWh)
~~January-March and December~~	$(0.00053)~~2187~~	$(0.00037)~~672~~
~~April-November~~	~~$0.00010~~	~~$0.00672~~

~~The Residential rate credit will end the earlier of December 31, 2023 or the billing month when the $30 million credit for Residential customers is calculated to be distributed in full. The All Other rate credit will end the earlier of December 31, 2023 or the billing month when the $10 million credit for All Other customers is calculated to be distributed in full. The rates set forth above may be adjusted in their final billing month to reconcile the amounts distributed to the $30 million credit available for distribution to Residential customers and the $10 million credit available for distribution to All Other customers.~~

~~4.~~7. The allocation of the Annual Revenue Requirement (ARR) which consists of the ~~actual~~ retail Generation and Distribution related ~~ARAM of~~ Protected Excess ADIT, the actual CAMT expenses and credits and any over or under-recovery based upon actual information for prior periods ~~Commission authorized amount of Unprotected Excess ADIT,~~ between residential and all other customers shall be based upon their respective contribution to total retail revenues, according to the following formula:

$$\text{Residential Allocation RA(y)} = \text{AC(y)} \times \frac{\text{KY Residential Retail Revenue RR}}{\text{KY Retail Revenue R}}$$

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All Other Allocation OA(y) = AC(y) x $\frac{\text{KY All Other Classes Retail Revenue OR}}{\text{KY Retail Revenue R}}$

Where:

(y)	=	the credit year;
RR	=	$301,523,011~~248,770,246~~;
OR	=	$392,479,515~~279,559,942~~; and
R	=	$694,002,526~~528,330,188~~.

8. The annual Federal Tax Change Tariff adjustments shall be filed with the Commission no later than October 15th of each year before it is scheduled to go into effect on Cycle 1 of the December billing cycle, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

9. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

Tariff C.F.F~~T~~.
(City's Franchise ~~Tarif~~Fee~~f~~)

Availability of Service

Where a city or town within Kentucky Power's service territory requires the Company to pay a percentage of revenues from certain customer classifications collected within such city or town for the right to erect the Company's poles, conductors, or other apparatus along, over, under, or across such city's or town's streets, alleys, or public grounds, the Company shall increase the rates and charges to such customer classifications within such city or town by a like percentage. The aforesaid charge shall be separately stated and identified on each affected customer's bill.

U.G.R.T.
(Utility Gross Receipts Tax)
(School Tax)

Applicable
To all Tariff Schedules.

Rate
This tariff schedule is applied as a rate increase pursuant to KRS 160.617 to all other tariff schedules for the recovery by the utility of the utility gross receipts license tax imposed by the applicable school district pursuant to KRS 160.613 with respect to the customer's bill. The current utility gross receipts license tax for school imposed by a school district may not exceed 3%. The utility gross receipts license tax shall appear on the customer's bill as a separate line item.

K.S.T.
(Kentucky Sales Tax)

Applicable
To all Tariff Schedules.

Rate
This tariff schedule is applied as a rate increase to all other applicable tariff schedules for the recovery by the utility pursuant to KRS 139.210 of the Kentucky Sales Tax imposed by KRS 139.200 for all customers not exempted by KRS 139.470(7). For any other exempt customers, an exemption certification must be received and on file with the Company. The Kentucky Sales Tax rate is currently imposed by the Commonwealth of Kentucky at the rate of 6%. The Kentucky Sales Tax shall appear on the customer's bill as a separate line item.

Sales of electricity under Tariff R.S. are exempt from sales tax only if the service is to the customer's place of domicile as defined by KRS 139.470(7)(b). Kentucky Power may retroactively charge a customer, under the parameters of KRS 278.225, for all applicable sales tax the Department of Revenue determines is due for service that is not exempt. It is the customer's responsibility to file all necessary documentation, including Form 51A380 (1-23), when notified by the Company, establishing the customer's place of domicile. In such a case, any exemption will become effective with the customer's first full billing cycle after the customer's delivery of a properly executed Form 51A380 (1-23).

~~Tariff K.F.R.F.~~
~~(EASTERN KENTUCKY FUEL RELIEF FUND)~~

~~Applicable~~
~~To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., R.S.-T.O.D. 2, R.S.D, G.S., S.G.S-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.~~

~~Rate~~

1. ~~Pursuant to the Public Service Commission's May 4, 2022 Order in Case No. 2021-00481, and contingent upon the closing of the acquisition of Kentucky Power by Liberty Utilities Co., Kentucky Power shall provide retail ratepayers a $40 million credit beginning the later of (a) the date on which Liberty Utilities Co. files written notice of its acquisition of Kentucky Power; or (b) July 1, 2022.~~

2. ~~The $40 million credit shall be allocated 75% to Residential customers ($30 million) and 25% ($10 million) to All Other customers, in accordance with Ordering Paragraph 13 and the manner illustrated in Appendix B of the Public Service Commission's May 4, 2022 Order in Case No. 2021-00481.~~

3. ~~The Residential rate credits and All Other rate credits shall be credited to customers on a kWh basis as follows:~~

~~Billing Month~~	~~Residential ($/kWh)~~	~~All Other ($/kWh)~~
~~January – March and December~~	~~XXXXX~~	~~XXXXX~~
~~April – November~~	~~XXXXX~~	~~XXXXX~~

~~The Residential rate credit will end the earlier of December 31, 2023 or the billing month when the $30 million credit for Residential customers is calculated to be distributed in full. The All Other rate credit will end the earlier of December 31, 2023 or the billing month when the $10 million credit for All Other customers is calculated to be distributed in full. The rates set forth above may be adjusted in their final billing month to reconcile the amounts distributed to the $30 million credit available for distribution to Residential customers and the $10 million credit available for distribution to All Other customers.~~

4. ~~The $30 million credit available for distribution to Residential customers and the $10 million credit available for distribution to All Other customers shall be subject to final reconciliation and distribution or collection by Order of the Commission in the Company's next base rate case.~~

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