

**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;	)	Case No. 2025-00257
(3) Approval Of Certain Regulatory And Accounting	)	
Treatments; and (4) All Other Required Approvals	)	
And Relief	)	

**SECTION III**  
**DIRECT TESTIMONIES**

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Case No. 2025-00257

**DIRECT TESTIMONY OF**  
**CYNTHIA G. WISEMAN**  
**ON BEHALF OF KENTUCKY POWER COMPANY**



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**I. INTRODUCTION**

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

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

**II. BACKGROUND**

5   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
6       **BUSINESS EXPERIENCES.**

7   A.   I received a Bachelor of Arts degree in Journalism with an emphasis in Public Relations  
8       from Marshall University in Huntington, West Virginia in 1989. I have also completed the  
9       International Economic Development Council’s Economic Development Institute at the  
10      University of Oklahoma. Prior to joining American Electric Power Company, Inc.  
11      (“AEP”), I spent most of my career in public relations and customer outreach. I worked for  
12      a public library system in Charleston, West Virginia for 15 years. I joined Kentucky Power  
13      affiliate Appalachian Power Company in 2008 and served in several capacities including  
14      communications, external affairs, and as a lobbyist. I joined Kentucky Power as Vice  
15      President, External Affairs and Customer Services in April 2018 and was named to my  
16      current position in April 2023.

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

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

10 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
11 **PROCEEDINGS?**

12 A. Yes. I testified in Case Nos. 2020-00174 and 2023-00159, the Company's most recent base  
13 rate cases. I also provided rebuttal testimony in response to the Public Service Commission  
14 of Kentucky's ("Commission") June 23, 2023, Order in Case No. 2021-00370.

### **III. PURPOSE OF TESTIMONY**

15 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
16 **PROCEEDING?**

17 A. The purpose of my Direct Testimony is to provide an overview of Kentucky Power and its  
18 role in the communities it serves as well as to identify the themes and major policy  
19 considerations reflected in the Company's application. Specifically, my Direct Testimony  
20 will:

- 21 • Provide an overview of Kentucky Power and its operations;
- 22 • Describe recent organizational changes at Kentucky Power and its parent
- 23 company, AEP, and how those changes benefit Kentucky Power's customers;

- Discuss Kentucky Power’s commitment to its customers and the ways the Company is furthering that commitment;
- Describe Kentucky Power’s need for this case;
- Summarize the themes and major policy considerations reflected in the application, including several measures proposed to reduce customer rate impacts and bill variability; and
- Identify and introduce the Company’s witnesses.

#### **IV. OVERVIEW OF KENTUCKY POWER**

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

A. Kentucky Power is a vertically-integrated utility engaged in the generation, purchase, transmission, and distribution of electric power to approximately 162,000 retail customers in 20 eastern Kentucky counties. It is a wholly-owned subsidiary of AEP. The Company is headquartered in Ashland, Kentucky, maintains distribution operations centers in Hazard, Pikeville, and Ashland, and smaller operations centers in Paintsville and Whitesburg. The Company’s distribution operations centers serve as a base of operations for employees. Company Witness Ross’s Direct Testimony describes the Company’s distribution system in more detail and discusses how Kentucky Power’s service territory includes some of the most geographically challenging terrain to serve in the Commonwealth.

Kentucky Power owns and operates the Big Sandy Plant located near Louisa, Kentucky. The Big Sandy Plant is a natural gas-fired boiler with a nameplate capacity of 295 MW. The Company also owns an undivided 50% interest in the Mitchell Generating Station (“Mitchell Plant”). The Mitchell Plant is comprised of two super-critical pulverized

1 coal-fired baseload generating units. Mitchell Unit 1 has a nameplate capacity of 770 MW  
2 and Mitchell Unit 2 has a nameplate capacity of 790 MW, for a total nameplate capacity  
3 of 1,560 MW. Kentucky Power's share of the Mitchell Plant is 780 MW. The Company's  
4 generation resources are described in more detail in the Direct Testimony of Company  
5 Witness Jessee.

6 **Q. PLEASE DESCRIBE KENTUCKY POWER'S WORKFORCE.**

7 A. Kentucky Power directly employs approximately 250 people across the Company's  
8 distribution and generation functions as well as general support staff. As further described  
9 by Company Witness Carlin, Kentucky Power pays competitive wages and benefits,  
10 enabling it to attract and retain the skilled workers required to provide safe, reliable, and  
11 efficient service to our customers. The Company continuously looks for opportunities to  
12 add staff in our service territory when the cost is justified by the service and customer  
13 benefits provided. Recently, through the AEP Service Corporation, 30 remote call center  
14 employees were hired from the Kentucky Power service territory.

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

20 **Q. HAVE ORGANIZATIONAL CHANGES AT AEP AFFECTED KENTUCKY**  
21 **POWER?**

22 A. Yes. In August 2024, Bill Fehrman became the Chief Executive Officer at AEP. In the  
23 period since this change, AEP has undergone an organizational restructuring to provide

1 more support to and authority for the operating companies, including Kentucky Power. As  
2 President and COO of Kentucky Power, I now directly report to the AEP CEO. As part of  
3 this reorganization, my responsibilities as President and COO of Kentucky Power have  
4 expanded to include direct control of generating plant operations, the Company's safety  
5 program, economic development, and workplace services. These changes reflect a  
6 refocusing of AEP's centralized functions as support for the operating companies.

7 **Q. DO THESE ORGANIZATIONAL CHANGES BENEFIT KENTUCKY POWER'S**  
8 **CUSTOMERS?**

9 A. Yes. The simplified organizational structure along with the expansion of my  
10 responsibilities as President and COO have streamlined Kentucky Power's operations. The  
11 local operating company focus has improved collaboration and internal relationships with  
12 service corporation teams, allowing Kentucky Power to better control costs with increased  
13 operational efficiencies. Kentucky Power still relies on the centralized expertise of the AEP  
14 Service Corporation to support activities for which it would be inefficient and more costly  
15 for Kentucky Power to provide the same services. This addresses services such as  
16 procurement, information technology, fuel purchasing, legal, accounting, and tax.  
17 However, the operating company focus has allowed Kentucky Power greater freedom in  
18 its strategic planning and decision making.

19 **Q. PLEASE PROVIDE AN EXAMPLE OF WHAT IS MEANT BY KENTUCKY**  
20 **POWER'S STRATEGIC PLANNING.**

21 A. Kentucky Power's and AEP's shared strategic vision is "Improving customers' lives with  
22 reliable, affordable power." Through its generation planning efforts, Kentucky Power is  
23 taking concrete steps to implement that vision. First, on June 30, 2025, the Company filed

1 an application in Case No. 2025-00175 for approval to make the investments necessary to  
2 continue taking 50% of the capacity and energy from the Mitchell Plant after December  
3 31, 2028. Second, as described in more detail in the Direct Testimony of Company Witness  
4 Wolfram, the Company has paid a reservation fee for a combustion turbine, a key step in  
5 the development of an additional dispatchable generation resource located in the  
6 Company's service territory to serve Kentucky Power's customers. These steps reflect  
7 Kentucky Power's commitment to providing reliable, "steel in the ground" generation  
8 resources to provide power to its customers while also creating stable and dependable jobs  
9 in eastern Kentucky.

10 **Q. CAN YOU DESCRIBE KENTUCKY POWER'S COST SAVINGS EFFORTS**  
11 **IMPLEMENTED SINCE THE LAST BASE RATE CASE?**

12 A. Yes. Reducing operating costs is important to Kentucky Power. As such, the Company has  
13 undertaken the following cost-saving efforts:

- 14 • Engaging in strategic hiring as Company personnel retire to ensure that the  
15 Company is correctly sized with the right personnel;
- 16 • Implementing the advanced metering infrastructure ("AMI") system approved  
17 by the Commission in Case No. 2024-00344 to reduce operational expenses  
18 incurred with current meters; and
- 19 • Proactive management of operation and maintenance ("O&M") expenses at the  
20 Big Sandy Plant and the Mitchell Plant to ensure that O&M expenses do not  
21 exceed budget as long as it does not jeopardize the safe, reliable, and efficient  
22 operation of the plant.

**V. KENTUCKY POWER'S COMMITMENT TO CUSTOMERS****Customer Service**

1   **Q.   PLEASE DESCRIBE KENTUCKY POWER'S CUSTOMER PHILOSOPHY.**

2   A.   Customer service, specifically an industry-best customer experience, is a core principle  
3       guiding everything we do. This is reflected in all our activities, including our reliability  
4       improvement efforts, vegetation management programs, storm restoration work,  
5       community and economic development activities, and customer assistance initiatives.  
6       Early this summer, to better understand our customers' concerns, Kentucky Power invited  
7       stakeholders from around the service territory to participate in community listening  
8       sessions in Hazard, Pikeville, and Ashland. Participants were presented with a list of  
9       questions to answer, which generated a robust discussion around rates, reliability,  
10      community involvement, customer communications, and education. The Kentucky Power  
11      leadership team took dozens of ideas away from these sessions. In a follow up survey,  
12      participants indicated they would be interested in continuing the conversation prompting  
13      Kentucky Power to work on establishing additional sessions, which the Company intends  
14      to do in the coming year.

**Charitable Giving**

15   **Q.   DOES KENTUCKY POWER AND ITS EMPLOYEES SUPPORT THE**  
16       **COMMUNITIES AND INSTITUTIONS IN THE COMPANY'S SERVICE**  
17       **TERRITORY?**

18   A.   Absolutely. The Company and its employees are active and productive members of the  
19       communities we serve. The Company contributes to charitable, educational, and civic  
20       organizations serving Kentucky Power's service territory. Kentucky Power employees



1 participate and volunteer in numerous community causes, including those that promote  
2 economic development, civic pride, and customer education and safety.

3 Additionally, the Kentucky Power Foundation and the AEP Foundation, charitable  
4 organizations supporting the customers of Kentucky Power, have recently made charitable  
5 contributions in our service area to support efforts to improve housing conditions and  
6 decrease hunger. Charitable contributions made by the AEP Foundation, as well as the  
7 Kentucky Power Foundation, are funded by the Company's shareholders; none are  
8 recovered through customer rates.

9 We recognize that we can do more together, and we are actively seeking partners  
10 with like goals. Each year, Kentucky Power partners with Facing Hunger and God's Pantry  
11 Food banks to raise money and collect food through an event called Power Up the Pantry.  
12 Likewise, Kentucky Power has partnered with organizations like Christian Appalachian  
13 Project, H.O.M.E.S., and the Housing Development Alliance to improve housing in eastern  
14 Kentucky, especially in the past few years as part of the High Ground initiative started by  
15 Governor Beshear. Of the Kentucky Power Foundation grants, one of the more notable  
16 recent ones was a \$1 million contribution in January 2025 to three Kentucky Community  
17 Action Agencies to help pay for home repairs necessary before customers can qualify for  
18 federally funded weatherization program assistance.

19 Kentucky Power further demonstrated its commitment to customers in the wake of  
20 the February 2025 flooding by supporting impacted communities through a coordinated  
21 effort involving employee-led initiatives, AEP Foundation grants, and hands-on  
22 volunteering. Alongside an employee organized supply drive, which resulted in a truck and  
23 trailer filled with essential items like cleaning supplies, food, and bottled water, the AEP

1 Foundation made total financial contributions of \$100,000 to bolster flood relief efforts,  
2 donating \$50,000 to the American Red Cross, \$25,000 to the Foundation for Appalachian  
3 Kentucky, and \$25,000 to the Appalachian Service Project. Kentucky Power, AEP, and  
4 their respective foundations will continue to support programs that help communities  
5 ensure that residents have safe places to call home and access to clean water and nutritious  
6 food.

### **Economic Development**

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

9 A. Economic development and business retention are important priorities to both Kentucky  
10 Power and its customers. The Company's service territory continues to see a decline in  
11 both customer count and load, as described by Company Witness Newcomb. There is a  
12 critical need for the Company to assist with efforts to maintain the existing customer base  
13 and further develop the region's economy to attract new customers and load.

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

21 Kentucky Power has positioned itself as the leader in economic development in  
22 eastern Kentucky by leveraging the expertise of its trained economic development team

1 and building strong relationships with regional and state economic development partners.  
2 This team works closely with local governments and regional economic development  
3 organizations to assist with business and industry recruitment, site development, and  
4 strategic initiatives aimed at fostering growth in the region. With three graduates from the  
5 University of Oklahoma Economic Development Institute and the support of the AEP  
6 Economic and Business Development team, Kentucky Power is well-equipped to address  
7 the unique challenges and opportunities that eastern Kentucky presents.

8 In addition to its internal resources, Kentucky Power holds executive board seats at  
9 several influential organizations, including One East Kentucky, the Northeast Kentucky  
10 Economic Development Authority, TENCO Workforce Development, and the Kentucky  
11 Association for Economic Development. The Company is also represented on the boards  
12 of the Southeast Kentucky Economic Development Corporation, the Hazard-Perry County  
13 Economic Development Alliance, the Greenup-Boyd Riverport Authority, the Southeast  
14 Kentucky Chamber of Commerce, the Northeast Kentucky Chamber of Commerce, the  
15 Kentucky Chamber of Commerce, and Leadership Kentucky. Through these partnerships,  
16 Kentucky Power helps to identify opportunities for growth and investment, aligning its  
17 efforts with the broader goals of economic revitalization in the area. This collaborative  
18 approach has allowed the Company to further support the local economy.

19 Lastly, in addition to these partnerships, Kentucky Power has supported successful  
20 economic development projects through its Kentucky Power Economic Growth Grant (“K-  
21 PEGG”) program that have resulted in the location of new customers, enhanced industrial  
22 sites and the creation of jobs in the Company’s service territory. It is important to build  
23 upon this momentum and continue to support economic development efforts for the benefit

1 of Kentucky Power's customers and the region. To that end, as Company Witness Cobern  
2 explains, the Company seeks approval in this case to continue its K-PEGG program at  
3 current funding levels to be collected through Tariff K.E.D.S.

**Customer Commitment Opportunities**

4 **Q. WHAT OTHER WAYS DOES KENTUCKY POWER SUPPORT ITS**  
5 **COMMITMENT TO CUSTOMERS?**

6 A. Kentucky Power has both near and long-term opportunities to advance its commitment to  
7 customers. The near-term opportunities, some of which are presented with this Application,  
8 include:

- 9 • Implementing a FlexPay program that gives customers more control over the  
10 timing of their bill payment;
- 11 • Implementing residential energy block billing to minimize the impact of high  
12 usage on customer bills;
- 13 • Reducing customer bill variability by increasing the percentage of fixed costs  
14 collected through fixed charges;
- 15 • Reversing some of the historical shift of costs from non-residential to residential  
16 customers;
- 17 • Implementing AMI to provide customers greater visibility into their usage;  
18 approved on July 22, 2025, by Commission Final Order in Case  
19 No. 2024-00344; and
- 20 • Implementing Demand Side Management ("DSM") programs approved on  
21 February 28, 2025, by Commission Final Order in Case No. 2024-00115.

1 **Q. DOES KENTUCKY POWER HAVE LONGER-TERM OPPORTUNITIES TO**  
2 **DEMONSTRATE ITS COMMITMENT TO CUSTOMERS?**

3 A. Yes. The long-term opportunities include:

- 4 • Evaluation of new, expanded, and/or enhanced DSM and energy efficiency  
5 programs to provide further energy and demand savings for customers;
- 6 • Establishing a generation portfolio that can provide the Company's customers  
7 with safe, reliable, and efficient dispatchable generation for decades to come  
8 including "steel in the ground" generation to be located in eastern Kentucky;  
9 and
- 10 • Smoothing of customer bill variability and reduction in large rate steps.

**VI. KENTUCKY POWER'S NEED FOR THIS CASE**

11 **Q. PLEASE BRIEFLY DESCRIBE KENTUCKY POWER'S NEED FOR THIS CASE.**

12 A. Kentucky Power's current rates were established in Case No. 2023-00159. These rates  
13 reflect the cost of providing electric service to customers based on a historic test year ended  
14 March 31, 2023, and an opportunity to earn a just and reasonable return on equity ("ROE")  
15 of 9.75%. The rates were ordered on January 19, 2024, for service rendered on and after  
16 January 16, 2024. Unfortunately, the current rates are deficient and do not allow Kentucky  
17 Power the opportunity to earn the reasonable return currently authorized by the  
18 Commission, as Kentucky Power is earning an ROE of 3.93% (as of May 2025). In turn,  
19 this impacts the ability of the Company to attract low-cost capital.

20 To fully recover the cost of providing electric service to customers, including the  
21 cost of equity capital, Kentucky Power is seeking to increase its annual revenue  
22 requirement by approximately \$95.6 million, an increase of approximately 14.62%.

1 Kentucky Power's need to file this case and the basis for the proposed revenue requirement  
2 increase is described in more detail in the Direct Testimony of Company Witness  
3 Newcomb.

4 **Q. WHAT MEASURES DID KENTUCKY POWER ADOPT TO MINIMIZE THE**  
5 **SIZE OF THE REQUESTED INCREASE IN THIS CASE?**

6 A. In addition to the day-to-day, Company-wide efforts to manage costs and provide service  
7 to our customers in the most efficient manner possible, Kentucky Power took the following  
8 steps to reduce the size of the requested increase in revenue requirement:

- 9 • The Company is proposing a capital structure that reduces the Company's  
10 equity layer which, in turn, reduces the Company's weighted average cost of  
11 capital. This measure is described in more detail in the Direct Testimony of  
12 Company Witness Newcomb.
- 13 • The Company is proposing an ROE of 10.0%, which is at the lowest end of the  
14 range recommended by Company Witness McKenzie who supported a range of  
15 10.0% to 11.0%.
- 16 • While the Company is proposing to update depreciation rates in this case, the  
17 Company is not proposing to adjust depreciation rates for the Mitchell Plant as  
18 discussed in the Direct Testimony of Company Witness Wolfram. Not only  
19 does this reduce immediate bill impacts to customers, it better positions the  
20 Company to pursue securitization of the Mitchell investments as further  
21 discussed by Company Witness Wolfram. Additional information regarding  
22 the depreciation study and proposed depreciation rates can be found in the  
23 Direct Testimony of Company Witness Spanos.

- The Company is proposing to remove storm expense from base rates and be authorized to automatically establish regulatory assets for all storm costs incurred. The Company is engaged with legislators and interested stakeholders to develop and pass legislation that would allow securitization of certain utility and regulatory assets including storm expense regulatory assets. Securitizing storm expense regulatory assets allows those costs to be paid for by customers over a longer period of time, bringing immediate rate relief to customers. Additional information about the Company's storm expense and its treatment in this case can be found in the Direct Testimony of Company Witness Wolfram.

**VII. OVERVIEW OF KENTUCKY POWER'S MAJOR PROPOSALS  
AND COST CONTROLS**

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

A. Kentucky Power has new faces on its leadership team. This leadership team is focused on working more collaboratively with stakeholders, being intentional with its regulatory proposals, and emphasizing a customer focus. To that end, below is a summary of Kentucky Power's major proposals in this case including:

- **New tariff rates, terms, and conditions:** In addition to the new base rates proposed in this case that are required as described above, the Company reviewed tariff rates, terms, and conditions and provided recommendations to be more customer friendly and reduce customer concerns. The Company considered customer inquiry and complaint data as part of its review and Kentucky Power is proposing modifications to tariff rates, terms, and conditions

1 to address: (1) historical shift of costs from non-residential to residential  
2 customers, and (2) customer bill variability, especially in high usage winter  
3 months. The Company is also proposing a new FlexPay program which will  
4 give residential customers a “pay-as-you-go” option that will allow customers  
5 better insight into their usage and the ability to control how and when payments  
6 are made.

- 7 • **Cost allocation**: Residential high bill concerns is the top complaint from our  
8 customers. One way that the Company is proposing to respond to residential  
9 high bill complaints is to address the historical shift of costs from  
10 non-residential to residential customers. As discussed earlier in my Direct  
11 Testimony, Kentucky Power’s revenue deficiency in this proceeding is  
12 calculated to be approximately \$95.6 million. The Company is proposing a band  
13 of reasonable outcomes around how the different classes of customers are  
14 allocated their fair share of the revenue increase. Specifically, no customer class  
15 should experience more than a 15% increase, which is described more fully in  
16 Company Witness Wolfram’s Direct Testimony.

- 17 • **Rate design**: Residential high bill concerns are the top complaint from our  
18 customers. Kentucky Power most frequently receives these residential high bill  
19 complaints during high usage periods typically during the winter months.  
20 Another way that the Company is proposing to respond to residential high bill  
21 complaints is to reduce customer bill variability by increasing the percentage of  
22 fixed costs collected through fixed charges. The impact of the Company’s



proposed rate design on high usage customers is described in more detail in the Direct Testimony of Company Witness Spaeth.

- **Generation Rider**: The Company is proposing a new Generation Rider to recover non-environmental Mitchell Plant capital plant balances, including associated depreciation expense. The Company is proposing the Generation Rider because it is continuing to pursue securitization legislation that would allow it to securitize the remaining net book value of the Mitchell Plant, and the Generation Rider would make reflecting securitization in rates more efficient. The Generation Rider is described in detail in the Direct Testimony of Company Witness Wolfram.

#### **VIII. IDENTIFICATION OF KENTUCKY POWER WITNESSES**

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

**A.** Kentucky Power is presenting 18 witnesses, other than myself, supporting the Company's proposals in this case. Table CGW-1 below summarizes and introduces each witness and provides a brief description of their Direct Testimony:

**Table CGW – 1: Kentucky Power's Witnesses**

<b>WITNESS</b>	<b>TOPICS</b>
Jeffrey D. Newcomb	<ul style="list-style-type: none"> <li>• Kentucky Power's revenue requirement and need for this case;</li> <li>• Kentucky Power's earned and requested return on equity;</li> <li>• Kentucky Power's proposed capital structure.</li> </ul>

WITNESS	TOPICS
Tanner S. Wolfram	<ul style="list-style-type: none"> <li>• Case organization and filing requirements;</li> <li>• Proposed changes to the Company's cost allocation, customer charges, and rate design;</li> <li>• Proposed changes to the Company's special and non-recurring charges;</li> <li>• Proposal to create a new rider mechanism to recover the non-environmental Mitchell Plant amounts;</li> <li>• Proposed changes to Tariff Purchase Power Adjustment ("Tariff P.P.A.");</li> <li>• Proposed changes to the Federal Tax Cut Tariff ("Tariff F.T.C.");</li> <li>• Requests for certain deferral and accounting treatment associated with the Company's proposals in this case;</li> <li>• The level of storm expense in base rates;</li> <li>• Certain proposed ratemaking adjustments.</li> </ul>
Michele Ross	<ul style="list-style-type: none"> <li>• An overview of the Company's service territory, distribution system, and operational challenges to providing safe, reliable and efficient service to Kentucky Power's customers;</li> <li>• The Company's reliability indices and performance;</li> <li>• The Company's distribution reliability programs, including the Company's proposed expansion of its trees outside the right-of-way and trees inside the right-of-way programs;</li> <li>• The reasonableness of the distribution capital investments the Company has made since its last base rate case;</li> <li>• The test year level of distribution O&amp;M expense;</li> <li>• The Company's AMI plan;</li> <li>• Details on the Company's Smart Grid investments.</li> </ul>
Robert A. Jessee	<ul style="list-style-type: none"> <li>• Kentucky Power's generation fleet;</li> <li>• The reasonableness of Kentucky Power's generation non-fuel, non-labor O&amp;M expenses for the Mitchell and Big Sandy Plants;</li> <li>• Capital investments placed in-service at Kentucky Power's generating assets since the Company's last base rate case.</li> </ul>
Stevi N. Cobern	<ul style="list-style-type: none"> <li>• The Company's proposal for the FlexPay program;</li> <li>• Maintaining the current funding level for the residential energy assistance and Kentucky Economic Development Surcharge;</li> <li>• Changes to the Company's tariffs and terms and conditions, including new tariff proposals and modifications to several existing tariffs.</li> </ul>

WITNESS	TOPICS
John D. Cullop	<ul style="list-style-type: none"> <li>• Update to the Company's base revenue requirement for its environmental surcharge;</li> <li>• Certain capitalization and rate base adjustments.</li> </ul>
Jaclyn N. Cost	<ul style="list-style-type: none"> <li>• Jurisdictional cost-of-service study;</li> <li>• Certain proposed ratemaking adjustments.</li> </ul>
Nicole M. Coon	<ul style="list-style-type: none"> <li>• Class cost-of-service study;</li> <li>• Allocation of requested increase to customer classes.</li> </ul>
Michael M. Spaeth	<ul style="list-style-type: none"> <li>• Overview of the relation between the Company's base rates and its surcharges and riders;</li> <li>• Rate design;</li> <li>• Certain proposed ratemaking adjustments.</li> </ul>
Franz D. Messner	<ul style="list-style-type: none"> <li>• Kentucky Power's proposed capital structure;</li> <li>• Kentucky Power's credit ratings.</li> </ul>
Adrien M. McKenzie	<ul style="list-style-type: none"> <li>• Calculation of a fair, just, and reasonable ROE range.</li> </ul>
Brian C. Ciborek	<ul style="list-style-type: none"> <li>• Certain known and measurable adjustments to the Company's revenues and operating expenses, rate base, and capitalization.</li> </ul>
David A. Hodgson	<ul style="list-style-type: none"> <li>• Calculate the Gross Revenue Conversion Factor;</li> <li>• Certain adjustments to the jurisdiction federal, state, and local income taxes to which Kentucky Power is subject;</li> <li>• Tax effects of certain fixed, known, and measurable ratemaking adjustments for the test year;</li> <li>• Certain modifications to the Company's existing Tariff F.T.C.</li> </ul>
Andrew R. Carlin	<ul style="list-style-type: none"> <li>• Employee compensation strategy and costs;</li> <li>• Associated pro forma adjustments.</li> </ul>
Clinton M. Stutler	<ul style="list-style-type: none"> <li>• Kentucky Power's natural gas procurement strategy;</li> <li>• Total amount of gains and losses on incidental gas sales included within the test year.</li> </ul>
Timothy S. Lyons	<ul style="list-style-type: none"> <li>• Lead/Lag study.</li> </ul>
John Wolfram	<ul style="list-style-type: none"> <li>• Zero-intercept study.</li> </ul>
John J. Spanos	<ul style="list-style-type: none"> <li>• Depreciation study.</li> </ul>

## **IX. CONCLUSION**

1    **Q.     DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2    **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 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.

Cynthia G. Wiseman

Cynthia G. Wiseman

Commonwealth of Kentucky )  
County of Boyd )

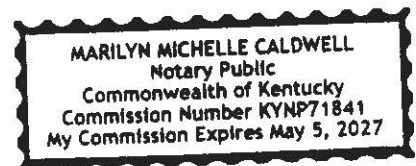
Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Cynthia G. Wiseman, on August 22, 2025.

Marilyn Michelle Caldwell  
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841



**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 Certain Regulatory And Accounting     )  
Treatments; and (4) All Other Required Approvals     )  
And Relief                                                         )

Case No. 2025-00257

**DIRECT TESTIMONY OF**  
**JEFFREY D. NEWCOMB**  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
JEFFREY D. NEWCOMB ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**DIRECT TESTIMONY OF  
JEFFREY D. NEWCOMB ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is Jeffrey D. Newcomb. I am the Vice President, Regulatory and Finance, for  
3       Kentucky Power Company (“Kentucky Power” or the “Company”). My business address  
4       is 1645 Winchester Avenue, Ashland, Kentucky 41101.

**II. BACKGROUND**

5   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
6       **BUSINESS EXPERIENCES.**

7   A.   I graduated from the Kelley School of Business, Indiana University, Bloomington, Indiana,  
8       in 2007 as a Bachelor of Science in Business Administration, and in 2008 as a Master of  
9       Business Administration, both with a major in Accounting. My professional career started  
10      with Ernst & Young, LLP, as an Intern during the summers of 2006 and 2007 before  
11      working full-time as an Associate from 2008 to 2010 and Senior Associate from 2010 to  
12      2011 with the firm’s tax practice in Chicago, Illinois. Prior to joining Kentucky Power, I  
13      worked for NiSource Inc. from 2011 to 2022, where I held various roles, including Senior  
14      Financial Analyst in Accounting, Lead Financial Planning Analyst, Lead Regulatory  
15      Strategy and Support Analyst, Capital Planning and Execution Manager, and Manager,  
16      Regulatory – Rate Case Optimization. I also was Senior Manager, Rates and Regulatory,

1 for Kentucky-American Water Company from October 2022 to August 2024. I accepted  
2 my current position with Kentucky Power in August 2024.

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

5 A. As Vice President, Regulatory and Finance, I am primarily responsible for managing the  
6 regulatory and financial strategies and business functions for Kentucky Power. I am  
7 responsible for managing the Company's financial operating plans, including preparation  
8 and coordination of various capital and operation and maintenance ("O&M") budgets to  
9 ensure that adequate resources such as debt, equity, and cash are available to build, operate,  
10 and maintain Kentucky Power's electric system assets used to provide service to the  
11 Company's retail customers. My responsibilities also include the planning and execution  
12 of rate applications and other regulatory filings, as well as applications for certificates of  
13 public convenience and necessity ("CPCNs") before the Public Service Commission of  
14 Kentucky ("Commission").

15 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
16 **PROCEEDINGS?**

17 A. Yes. I have previously filed testimony before this Commission in support of  
18 Kentucky-American Water Company's Qualified Infrastructure Program ("QIP") in Case  
19 Nos. 2023-00030 ("QIP 4"), 2023-00300 ("QIP 3 Balancing Adjustment"), and  
20 2024-00173 ("QIP 5"), as well as in support of Kentucky-American Water Company's  
21 application for an adjustment of base rates in Case No. 2023-00191. I have also previously  
22 submitted testimony before the Indiana Utility Regulatory Commission in support of  
23 Northern Indiana Public Service Company LLC's gas base rate case in Cause No. 45621



1 and the Public Service Commission of Maryland in support of Columbia Gas of Maryland's  
2 gas base rate case in Case No. 9644.

### III. PURPOSE OF TESTIMONY

3 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
4 **PROCEEDING?**

5 A. The purpose of my Direct Testimony is to discuss the major regulatory and financial policy  
6 considerations contained in the Company's application for an adjustment of base rates in  
7 this proceeding. Specifically, my Direct Testimony will:

- 8 • Describe the revenue requirement and Kentucky Power's need for this case;
- 9 • Discuss Kentucky Power's earned and requested return on equity; and
- 10 • Provide Kentucky Power's proposed modifications to its capital structure.

### IV. REVENUE REQUIREMENT

11 **Q. WHAT IS THE TEST YEAR IN THIS CASE?**

12 A. Kentucky Power used a historical test year of the 12 months ended May 31, 2025, and has  
13 made pro forma adjustments to normalize the test year and reflect any known and  
14 measurable increases or decreases to test-year expenses, investments, financings, and  
15 revenues going forward.

16 **Q. WHAT COMPRISES KENTUCKY POWER'S ANNUAL REVENUE**  
17 **REQUIREMENT?**

18 A. Kentucky Power's annual revenue requirement is equal to the cost of providing electric  
19 service to approximately 162,000 customers in all or part of 20 eastern Kentucky counties  
20 (including Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott,  
21 Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and

1 Rowan Counties), plus an opportunity to earn a just and reasonable return on equity  
2 (“ROE”) invested to ensure the long-term provision of adequate and reliable electric  
3 service.

4 Providing electric service is an extensive and cost intensive endeavor that starts  
5 with sourcing adequate electric power generation to accommodate peak usage and demand  
6 from either Kentucky Power’s Big Sandy Power Plant (“Big Sandy Plant”), the Mitchell  
7 Plant (“Mitchell Plant”), or the PJM Interconnection, LLC (“PJM”) market. It also includes  
8 transmitting and distributing that electric power through the Company’s over 11,400 miles  
9 of power lines attached to over 228,000 poles to reach all of the homes, businesses, schools,  
10 and industries throughout its nearly 5,000 square mile service territory, which includes  
11 some of the most geographically challenging terrain to serve in the Commonwealth.  
12 Kentucky Power also provides customer service, monthly billing, 24-hour call handling,  
13 and a self-service website.

14 To provide that service, Kentucky Power necessarily incurs costs for which it then  
15 seeks recovery through customer rates. The Company’s costs include a variety of operating  
16 expenses, depreciation and amortization, and various local, state, and federal taxes.  
17 Kentucky Power also must be granted the opportunity to earn a reasonable return on  
18 approximately \$1.9 billion of electric rate base that supports the Company’s provision of  
19 service to customers.

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

3   A.   Kentucky Power's revenue requirement in this proceeding is based on the historical test  
4   year described above and is equal to the cost of providing service plus an opportunity to  
5   earn a reasonable return.

6           The Company proposes a total annual base revenue requirement increase of  
7   \$75,269,689. Section V, Schedule 2 shows how Kentucky Power derived the change in  
8   base revenue requirement increase. The proposed annual base rate revenue requirement  
9   increase represents approximately 11.52%, over the Test Year ended May 31, 2025  
10   adjusted total retail revenues of \$653,489,895. The Company is also proposing a new  
11   Generation Rider, which has an initial revenue requirement of \$20,288,559. Taken  
12   together, the total revenue requirement increase is \$95,558,248. The total proposed annual  
13   revenue requirement increase represents approximately 14.62%, over the Test Year ended  
14   May 31, 2025 adjusted total retail revenues of \$653,489,895. The total increase to base  
15   rates proposed by the Company are designed to produce \$672,038,794 in annual total base  
16   rate revenues. Please refer to Section V, the Summary Tab and Schedule 1, for the  
17   derivation of the proposed base rate revenue requirement, which is supported by Company  
18   Witness Wolffram.

19   **Q.   PLEASE DESCRIBE HOW KENTUCKY POWER'S REVENUE DEFICIENCY,**  
20   **WHICH INFORMS THE INCREASE IN ANNUAL REVENUES PROPOSED IN**  
21   **THIS CASE, IS DERIVED.**

22   A.   Kentucky Power's revenue deficiency, found in Section V, Exhibit 1, and sponsored by  
23   Company Witness Wolffram, is measured as the difference between the revenue

1 requirement described above and the Company's adjusted test-year retail sales revenues,  
2 which are approximately \$653.5 million. Kentucky Power's revenue deficiency in this  
3 proceeding is calculated to be approximately \$95.6 million, which is an approximate 14.6%  
4 deficiency.

5 **Q. PLEASE SUMMARIZE THE DEVELOPMENT OF THE PROPOSED ANNUAL**  
6 **REVENUE REQUIREMENT, EXCLUDING THE GENERATION RIDER,**  
7 **PRESENTED IN SCHEDULE 1 OF SECTION V, EXHIBIT 1.**

8 A. Schedule 1 summarizes the components of Net Electric Operating Income for the 12  
9 months ended May 31, 2025, as adjusted, under present rates in Column 3, and the effects  
10 of the proposed rate increase on those components in Column 4. Also shown are the  
11 components of Net Electric Operating Income after giving effect to the proposed rate  
12 increase in Column 5. The total amount of rate base and capitalization is also shown along  
13 with the calculated overall rates of return.

14 **Q. WHAT DRIVES THE NEED FOR THIS CASE?**

15 A. Kentucky Power is at a significant inflection point in the Company's journey to "Improving  
16 customers' lives with reliable, affordable power." The need for this case is fundamentally  
17 driven by the Company's financing and capital investment needs to ensure the long-term  
18 reliability of electric service.

19 Kentucky Power is also at a significant point of time for capital investment with,  
20 for example, its metering program, generation portfolio, and vegetation management  
21 program. The investments being made in these programs are in addition to other capital  
22 investments that have been made since March 31, 2023, which was the historical test year  
23 used to establish current base rates in Case No. 2023-00159. Specifically, the Company

1 needs to reflect the capital that has and will be invested between now and the end of the  
2 post-test-year pro forma adjustment period. This includes the Company's 50% interest in  
3 the Mitchell Plant and increased trimming of trees outside the right-of-way ("TOR"), in  
4 addition to other capital investments.

5 Kentucky Power also plans to invest in in-state dispatchable generation to  
6 complement the Big Sandy Plant and the Mitchell Plant by building a new 450 MW natural  
7 gas-fired combustion turbine at the existing Big Sandy Plant site. This is a significant  
8 investment and also is a driver of the need for this case to ensure Kentucky Power can  
9 attract low-cost capital to make that important investment.

10 Lastly, the placement of approximately \$477.7 million of securitization bonds in  
11 June 2025 also drives the need to reflect an updated capital structure and cost of capital,  
12 which is ultimately used to derive rates. For that reason, the Company proposes to reflect  
13 in its capital structure the repayment of \$300 million in term loans as a reduction to  
14 long-term debt, the repayment of approximately \$85.2 million of short-term debt, and is  
15 proposing an equity reduction of approximately \$83.1 million. I explain these proposals  
16 later in my Direct Testimony, and Company Witness Messner provides additional detail in  
17 his Direct Testimony.

## **V. CURRENTLY EARNED AND REQUESTED RETURN ON EQUITY**

### **Q. WHAT IS THE COMPANY'S CURRENTLY AUTHORIZED ROE?**

19 A. Kentucky Power's current Commission-authorized ROE is 9.75%, as approved by the  
20 January 19, 2024, Order in Case No. 2023-00159.<sup>1</sup>

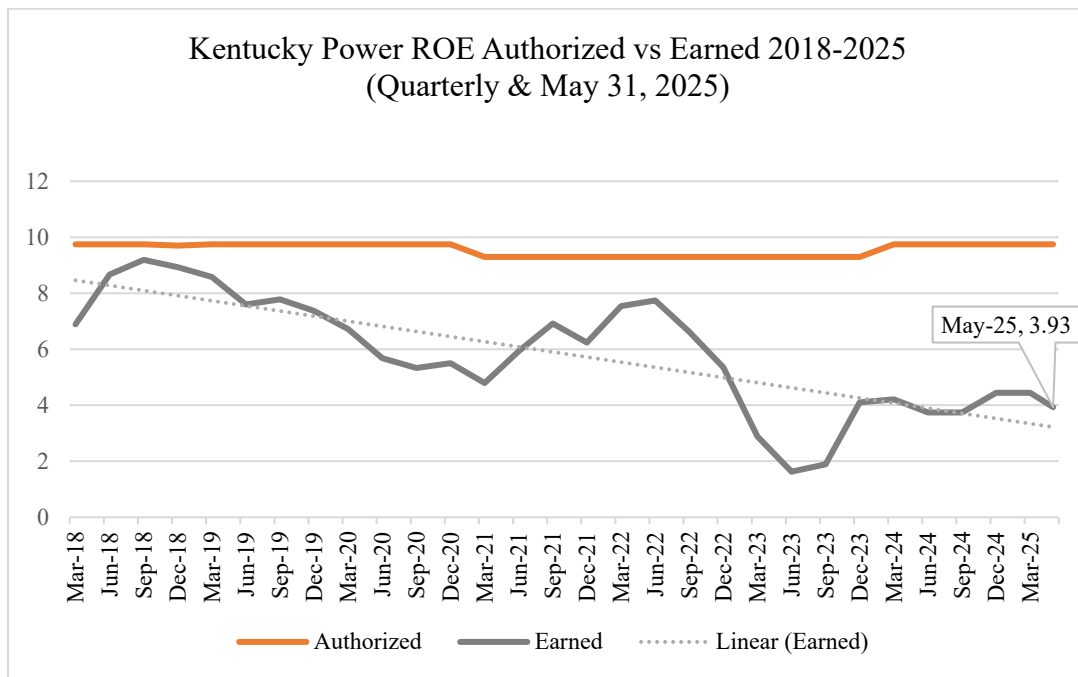
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<sup>1</sup> See Order at 61, *In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) A Securitization Financing Order; And (5) All Other Required Approvals And Relief*, Case No. 2023-00159, (Ky. P.S.C. Jan. 19, 2024).

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

A. No. Figure JDN-1 below compares Kentucky Power's quarterly earned ROE to its authorized ROE from Q1 2018 through May 31, 2025. As shown, the Company has been unable to earn its authorized ROE during that period, which must be prospectively addressed for the Company to continue providing adequate and reliable service to customers.

**Figure JDN-1**



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

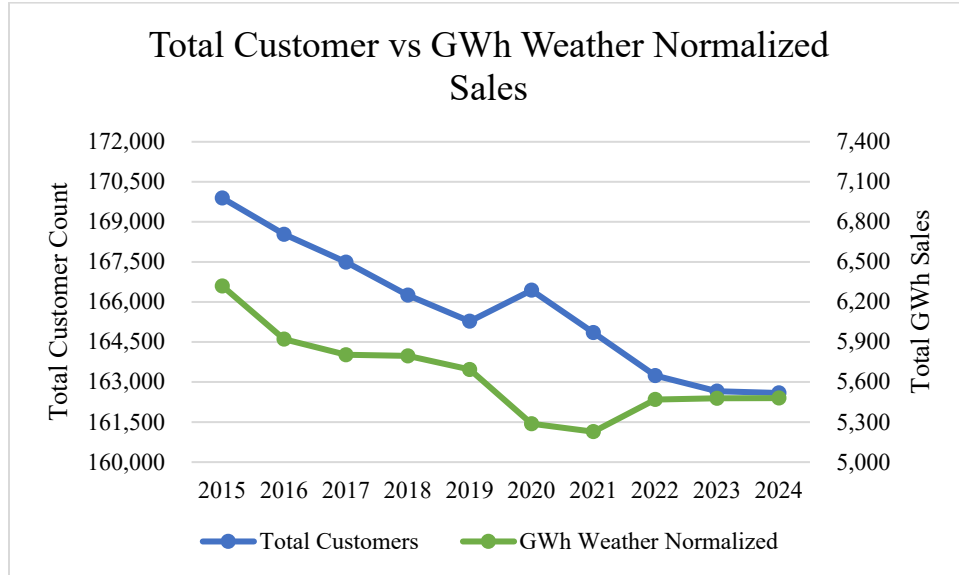
A. The Company's earned ROE for the 12 months ended May 31, 2025, was 3.93%. This is far below the ROE found to be just and reasonable by the Commission in Case No. 2023-00159, or otherwise, especially considering that new base rates were recently established for service rendered on and after January 16, 2024, to provide an opportunity to earn an authorized ROE of 9.75%.

1 **Q. WHAT IS DRIVING KENTUCKY POWER'S EARNED ROE TO TREND**  
2 **LINEARLY DOWNWARD?**

3 A. This downward linear trend is driven by two main factors. First, the Company has  
4 experienced the loss of significant non-residential customers that has contributed to the  
5 revenue deficiency driving both this case and past base rate cases. In between base rate  
6 cases, the loss of customers results in downward pressure on earned ROE because the rates  
7 being charged are insufficient to produce the approved revenue requirements from which  
8 those rates were derived. Second, regulatory lag on increases to non-rider eligible rate base  
9 and increases to non-rider eligible operating and interest expense between base rate cases  
10 has put additional downward pressure on earned ROE.

11 **Q. HOW HAS KENTUCKY POWER'S CUSTOMER COUNT AND WEATHER**  
12 **NORMALIZED SALES CHANGED IN THE LAST 10 YEARS?**

13 A. Kentucky Power's customer count and weather normalized usage have been trending  
14 linearly downward since 2015. Figure JDN-2 shows that total customer count has  
15 decreased by 8,128 customers from 169,893 as of December 31, 2015, to 161,765 as of  
16 May 31, 2025. Figure JDN-2 also shows that total weather normalized usage has decreased  
17 by 957 gigawatt hours ("GWh") since 2015 from 6,319 GWh for the 12 months ended  
18 December 31, 2015, to 5,362 GWh for the 12 months ended May 31, 2025.

**Figure JDN-2**

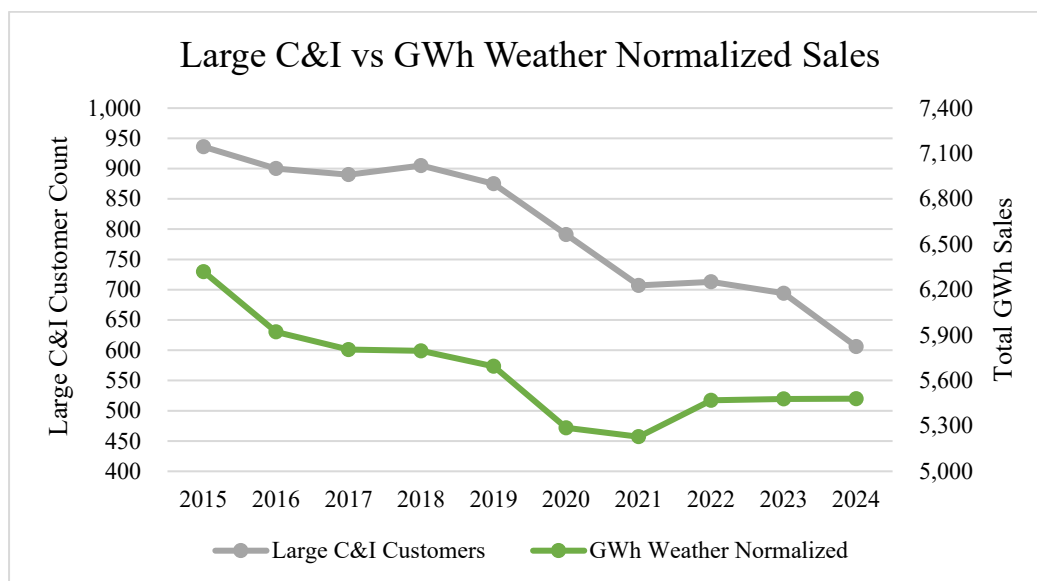
**Q. HOW HAS KENTUCKY POWER’S CUSTOMER COUNT CHANGED IN THE LAST 10 YEARS SPECIFIC TO LARGE COMMERCIAL AND INDUSTRIAL (“C&I”) CUSTOMERS?**

**A.** Kentucky Power’s large C&I customer count has also been trending linearly downward since 2015. Figure JDN-3 shows that large C&I customer count has decreased by 316 customers from 936 as of December 31, 2015, to 620 as of May 31, 2025. Figure JDN-3 also shows that total weather normalized sales follows the trend in large C&I customer



count and decreased by 957 GWh since 2015 from 6,319 GWh for the 12 months ended December 31, 2015, to 5,362 GWh for the 12 months ended May 31, 2025.

**Figure JDN-3**



**Q. PLEASE DESCRIBE KENTUCKY POWER’S DECLINE IN CUSTOMER COUNT SINCE ITS LAST BASE RATE CASE AND ITS IMPACT.**

A. Kentucky Power’s customer count has declined by 1,598 customers since its last base rate case from 163,363 as of March 31, 2023, to 161,765 as of May 31, 2025. The decline in customer count, particularly the decline in large C&I customer count from 664 as of March 31, 2023, to 620 as of May 31, 2025, in addition to the loss of two wholesale customers in 2025, has contributed to Kentucky Power’s revenue deficiency in this case with fewer customers over which to spread the fixed costs of providing electric service.

**Q. PLEASE DESCRIBE KENTUCKY POWER’S DECLINE IN WEATHER NORMALIZED SALES SINCE ITS LAST BASE RATE CASE AND ITS IMPACT.**

A. Kentucky Power’s weather normalized sales have declined 130 GWh from 5,493 GWh for the 12 months ended March 31, 2023, to 5,362 GWh for the 12 months ended May 31,

1 2025. The decline in weather normalized sales has contributed to Kentucky Power's  
2 revenue deficiency and the need for this case. The impact of this decline in usage has been  
3 magnified by the fact that the Company does not collect 100% of its fixed costs of  
4 providing electric service through fixed charges.

5 **Q. PLEASE DESCRIBE THE HISTORICAL SHIFT OF COSTS FROM**  
6 **NON-RESIDENTIAL TO RESIDENTIAL CUSTOMERS AS A RESULT OF THE**  
7 **LOSS OF SIGNIFICANT NON-RESIDENTIAL CUSTOMERS.**

8 A. The loss of significant non-residential customers has resulted in a shift of the costs incurred  
9 to meet the demand imposed by those customers from the non-residential class to the  
10 residential class, particularly fixed costs that use demand as the basis to allocate those costs  
11 between the non-residential and residential classes. The demand of a non-residential  
12 customer is typically significantly higher than the demand of a residential customer, so the  
13 loss of significant non-residential customers that Kentucky Power has experienced, such  
14 as those in mining, metals, and manufacturing, has resulted in a shift of costs to the  
15 residential class.

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

19 A. Kentucky Power is an important part of the fabric of eastern Kentucky as a service provider,  
20 employer, corporate citizen, and investor. It is important to note that public utilities are  
21 provided an opportunity to earn a reasonable return on investment to ensure that they can  
22 attract low-cost capital to invest for customers' long-term benefit. Indeed, as previously  
23 discussed, the need to file this case is fundamentally driven by financing and capital

1 investment needs to ensure the long-term reliability of electric service. Continued or  
2 sustained poor financial performance will adversely affect the capital available to the  
3 Company and that capital's cost, as well as Kentucky Power's ability to continue to provide  
4 reliable service to customers while remaining an important part of eastern Kentucky.  
5 Company Witness McKenzie discusses in detail the basis for his recommended ROE range  
6 and the importance of Kentucky Power being permitted the opportunity to earn it.

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

12 As a public utility, the Company abides by federal, state, and local rules and  
13 regulations, including those of the Commonwealth and the Commission. Under the  
14 regulatory compact, Kentucky Power provides safe and reliable service in return for an  
15 opportunity to earn a just and reasonable return on its investments for the long-term  
16 reliability of electric service for the Company's customers. As has been described above,  
17 Kentucky Power's existing rates are deficient and new base rates should be established  
18 equal to the cost of providing electric service and provide a return at least equal to the  
19 Company's cost of capital.

20 Lastly, earning an ROE less than that authorized over a sustained period creates a  
21 vicious cycle of adversely impacting the financial health of the public utility and increasing  
22 the reliance on debt to finance the cash needs of the business. Increased reliance on debt  
23 not only results in additional interest expense, but it also impacts the ability to attract

1 low-cost capital to invest in infrastructure. Reduced ability to invest in infrastructure  
2 impacts the ability to ensure service quality and reliability. There are also possible broader  
3 economic implications. Reliable and affordable power is crucial for economic activity in  
4 the service territory. In sum, earning an ROE less than that authorized over a sustained  
5 period can negatively impact businesses, deter investment, and impede regional economic  
6 growth.

7 **Q. WHAT OTHER FACTORS IMPACT KENTUCKY POWER'S ABILITY TO**  
8 **ATTRACT LOW-COST CAPITAL?**

9 A. In addition to the low level of earned ROE, Kentucky Power's credit rating and funds from  
10 operations ("FFO") as a percentage of debt ("FFO/Debt") impact the Company's ability to  
11 attract low-cost capital. Kentucky Power's current credit rating at Moody's is Baa3 (the  
12 lowest investment-grade rating) and at Standard & Poor's ("S&P") is BBB (the second  
13 lowest investment-grade rating). The Company's FFO/Debt for the 12 months ended May  
14 31, 2025, was 8.08%, which is below Kentucky Power's downgrade threshold from  
15 Moody's of 11%. The June 2025 placement of securitization bonds will help the  
16 Company's FFO/Debt, but fair, just, and reasonable new base rates also need to be  
17 established to reflect Kentucky Power's updated capital structure and cost of capital, as

well as to ensure an appropriate FFO/Debt is maintained going forward to prevent further downgrade of the Company's credit ratings.

## **VI. PROPOSED MODIFICATIONS TO CAPITAL STRUCTURE**

**Q. PLEASE PROVIDE THE COMPANY'S CURRENTLY-APPROVED CAPITAL STRUCTURE.**

A. The Company's currently-approved capital structure was established by the Commission's January 19, 2024, Order in Case No. 2023-00159 and is presented below as Figure JDN-4.

**Figure JDN-4**

<u>Type of Capital</u>	<u>Amount</u>	<u>Ratios</u>
Long-Term Debt	\$953,708,560	52.62%
Short-Term Debt	\$111,251,046	6.14%
Common Equity	<u>\$747,579,969</u>	<u>41.25%</u>
Total	\$1,812,539,574	100%

**Q. HOW DID THE PLACEMENT OF SECURITIZATION BONDS IN JUNE 2025 AFFECT THE COMPANY'S CAPITAL STRUCTURE?**

A. The placement of approximately \$477.7 million of securitization bonds in June 2025, net of approximately \$9.4 million of upfront financing costs, resulted in proceeds of approximately \$468.3 million. Kentucky Power has utilized \$300 million of the net proceeds for the repayment of two \$150 million term loans, reducing the amount of long-term debt in its current capital structure, and \$85.2 million for the repayment of its short-term debt balance as May 31, 2025, reducing the amount of short-term debt in its capital structure.

1   **Q.   WHAT MODIFICATIONS TO THE CAPITAL STRUCTURE DOES KENTUCKY**  
2       **POWER PROPOSE IN ORDER TO ADDRESS THE EFFECTS OF**  
3       **SECURITIZATION?**

4   A.   The Company proposes to make certain adjustments to the test year capital structure and  
5       weighted average cost of capital (“WACC”) to adjust for the use of proceeds from the June  
6       2025 issuance of securitization bonds. Company Witness Messner describes the proposed  
7       capital structure and WACC in more detail in his Direct Testimony. Generally, the  
8       Company proposes to reflect in its capital structure the repayment of \$300 million in term  
9       loans as a reduction to long-term debt, the repayment of approximately \$85.2 million of  
10      short-term debt, and is proposing an equity reduction of approximately \$83.1 million.

11           Absent the proposed equity reduction, the revenue requirement and WACC in this  
12      case would increase as a result of a higher ratio of common equity in the Company’s capital  
13      structure which generally carries a higher cost than long-term and short-term debt.

14           The use of the securitization proceeds and the proposed capital structure are  
15      consistent with the Commission’s prior directives. For example, in the Company’s last base  
16      rate case, in approving the Company’s current capital structure, the Commission said,  
17      “[t]he Commission expects Kentucky Power to find cost-effective measures to improve its  
18      current credit rating of Baa3 and corporate credit rating of BBB while keeping its capital  
19      structure reasonably balanced so that it does not over burden its ratepayers to the benefit  
20      of shareholders, but that Kentucky Power would nevertheless have the ability to reasonably  
21      attract capital.”<sup>2</sup> Each of the proposed modifications to the capital structure effectuate the  
22      Commission’s directives in that order.

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<sup>2</sup> *Id.* at 50.

1   **Q.   WHAT WOULD BE THE EFFECTS IF THE COMPANY'S PROPOSED**  
2       **MODIFICATIONS TO THE CAPITAL STRUCTURE ARE NOT APPROVED?**

3   A.   If the Company's proposed modifications to the capital structure are not approved, the  
4       capital structure would not reflect known and measurable changes and the resulting new  
5       base rates would not provide the Company an opportunity to earn the ROE authorized in  
6       this proceeding. Likewise, any capital riders that would use the resulting approved WACC  
7       would also not provide the Company an opportunity to earn the ROE authorized in this  
8       proceeding on their respective rider-eligible rate bases.


**VII. CONCLUSION**

9   **Q.   DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

10  A.   Yes, it does.

## VERIFICATION

The undersigned, Jeffrey D. Newcomb, being duly sworn, deposes and says he is the Vice President of Regulatory and Finance for Kentucky 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.

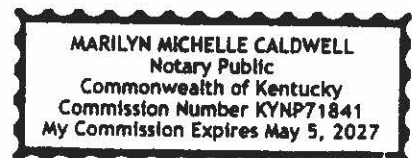
  
\_\_\_\_\_  
Jeffrey D. Newcomb

Commonwealth of Kentucky )  
                                          )  
County of Boyd )

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffrey D. Newcomb, on August 26, 2025.

  
\_\_\_\_\_  
Notary Public



My Commission Expires May 5, 2027

Notary ID Number KYNP71841



**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 Certain Regulatory And Accounting    )  
Treatments; and (4) All Other Required Approvals    )  
And Relief                                                        )

Case No. 2025-00257

**DIRECT TESTIMONY OF**  
**TANNER S. WOLFFRAM**  
**ON BEHALF OF KENTUCKY POWER COMPANY**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT TSW-1	Support for Special Charges
EXHIBIT TSW-2	Generation Rider Rate Design
EXHIBIT TSW-3	Generation Rider Tariff

**DIRECT TESTIMONY OF  
TANNER S. WOLFFRAM ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is Tanner S. Wolfram and I am Director of Regulatory Services for Kentucky  
3       Power Company (“Kentucky Power” or the “Company”). My business address is 1645  
4       Winchester Avenue, Ashland, Kentucky 41101.

**II. BACKGROUND**

5   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
6       **BUSINESS EXPERIENCES.**

7   A.   I received a Bachelor of Arts degree in Political Science from Miami University in  
8       Oxford, Ohio in 2015 and my Juris Doctor from The Ohio State University in Columbus,  
9       Ohio in 2018. I began my utility industry career with American Electric Power Service  
10      Corporation (“AEPSC”) in September 2018 as a Legal Fellow, where I worked on a variety  
11      of matters across AEP’s various jurisdictions. In September 2019, I was hired as  
12      Counsel – Regulatory East, where I was responsible for providing legal support and  
13      guidance on various complaint, fuel cost recovery, tracker/rider, and base rate proceedings  
14      in AEP’s East jurisdictions, primarily for Kentucky Power Company, Indiana Michigan  
15      Power Company, and Ohio Power Company. In June 2021, I transferred to AEPSC’s  
16      central regulatory function as a Regulatory Case Manager, where I coordinated state  
17      regulatory filings across AEP’s footprint. My primary responsibilities were related to

1 filings made in Kentucky, Ohio, and Indiana. In July 2024, I accepted my current position  
2 as Director, Regulatory Services for Kentucky Power.

3 **Q. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR OF REGULATORY**  
4 **SERVICES FOR KENTUCKY POWER?**

5 A. I am responsible for managing the regulatory strategy for Kentucky Power. This includes  
6 planning and executing rate filings for state regulatory agencies, as well as filings for  
7 certificates of public convenience and necessity and for other approvals before the Public  
8 Service Commission of Kentucky (“Commission”).

9 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY**  
10 **PROCEEDINGS?**

11 A. Yes. I adopted the Direct Testimony of Scott E. Bishop and submitted rebuttal testimony  
12 in the Company’s most recent Demand-Side Management proceeding, Case  
13 No. 2024-00115. I also provided testimony in the Company’s requests for approval of a  
14 Renewable Energy Purchase Agreement for the Bright Mountain Solar Facility in Case  
15 No. 2024-00243, approval of a certificate of public convenience and necessity (“CPCN”)  
16 for the Bellefonte Station Upgrade Project in Case No. 2024-00343, and approval of a  
17 CPCN to extend the Company’s interest in the energy and capacity from Mitchell  
18 Generating Station (“Mitchell” or “Mitchell Plant”) in Case No. 2025-00175.

### **III. PURPOSE OF TESTIMONY**

19 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
20 **PROCEEDING?**

21 A. The purpose of my Direct Testimony is to support:

- 22 • Case organization and filing requirements;

- Proposed changes to the Company’s cost allocation, customer charges, and rate design;
- Proposed changes to the Company’s special and non-recurring charges;
- The Company’s proposal to create a new rider mechanism, the Generation Rider, to recover non-environmental Mitchell Plant amounts;
- Proposed changes to Tariff Purchase Power Adjustment (“Tariff P.P.A.”);
- Proposed changes to Federal Tax Cut Tariff (“Tariff F.T.C.”);
- Requests for certain deferral and accounting treatment associated with the Company’s proposals in this case;
- The level of storm expense in base rates; and
- Certain proposed ratemaking adjustments.

**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

These schedules provide details of the capitalization and rate base amounts, as well as the revenue requirement.

**Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following exhibits:

<u>EXHIBIT</u>	<u>DESCRIPTION</u>
Exhibit TSW-1	Support for Special Charges
Exhibit TSW-2	Generation Rider Rate Design

Exhibit TSW-3

Generation Rider Tariff

1 **Q. WERE THESE SCHEDULES AND EXHIBITS PREPARED BY YOU OR UNDER**  
2 **YOUR DIRECTION?**

3 A. Yes.

**IV. CASE ORGANIZATION AND FILING REQUIREMENTS**

4 **Q. PLEASE DESCRIBE HOW THE COMPANY HAS ORGANIZED THE VARIOUS**  
5 **ELEMENTS OF THIS CASE.**

6 A. This case has been organized into the following components:

- 7 • Section I: Application;
- 8 • Section II: Minimum filing requirements in support of the Company's application  
9 in conformity with 807 KAR 5:001, Section 16, 807 KAR 5:011, and other  
10 applicable provisions;
- 11 • Section III: Prepared Direct Testimony and exhibits in support of the Company's  
12 application in conformity with 807 KAR 5:001, Section 16;
- 13 • Section IV: Financial exhibit in the form prescribed by 807 KAR 5:001, Section  
14 12. Balance sheet data is shown as of May 31, 2025, and income statement data is  
15 shown for the 12 months ended May 31, 2025; and
- 16 • Section V: Description and quantification of all proposed adjustments, with proper  
17 support for any proposed changes as prescribed by 807 KAR 5:001, Section 16.

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

20 A. Yes. The information required to be filed with a general rate case, including those  
21 requirements set forth in 807 KAR 5:001, Section 16 and 807 KAR 5:011, are presented

1 in Section II (filing requirements), Section III (testimony), and Section V (adjustments)  
2 of the Company's filing.

**V. PROPOSED CHANGES TO CUSTOMER CLASS ALLOCATIONS**

3 **Q. IS THE COMPANY PROPOSING ANY CHANGES TO HOW IT ALLOCATES**  
4 **COSTS ON A JURISDICTIONAL AND CLASS BASIS?**

5 A. Yes. First, the Company provided service to two wholesale customers, the City of  
6 Vanceburg and the City of Olive Hill during the test year. The Company's wholesale  
7 contracts with those two customers terminated at the end of May 2025 and, therefore, the  
8 Company has removed the wholesale jurisdiction from its jurisdictional cost-of-service.  
9 Company Witness Cost sponsors the going-level adjustment required to effectuate this  
10 change (Adjustment W18).

11 Additionally, when the Company performed its class cost-of-service analysis in the  
12 preparation of this case, the results showed that both the industrial and residential customer  
13 classes were receiving subsidies from the other customer classes. The residential class has  
14 historically received a subsidy from other classes, and the Company proposed to maintain  
15 the existing residential class subsidy in its 2023 base rate case. After reviewing the results  
16 of the class cost-of-service analysis prepared for this case by Company Witness Coon, the  
17 results showed that eliminating the interclass subsidy to the residential class would result  
18 in a significant rate increase for the average residential customer. However, even  
19 maintaining the existing subsidy would result in an approximate 18.5% increase for the  
20 average residential customer. Accordingly, Company Witness Wiseman, Company  
21 Witness Newcomb, and I made the decision to limit the average increase for each customer  
22 class to no more than 15%, inclusive of the Generation Rider, which is discussed further

below. Based on that directive, Company Witness Coon allocated the proposed revenue increase to ensure no customer class received more than a 15% total rate increase. This allocation resulted in the following proposed base rate increases for the average customer in each customer class:

**Figure TSW-1**

<b>Class</b>	<b>Base Increase Compared to Test Year</b>	<b>Generation Rider Compared to Test Year</b>	<b>Total Rate Increase Compared to Test Year</b>
Residential	11.5%	3.4%	14.9%
General Service	11.4%	2.4%	13.8%
Large General Service	11.9%	2.5%	14.4%
Industrial General Service	11.5%	3.4%	15.0%
Municipal Waterworks	11.5%	2.0%	13.5%
Outdoor Lighting	11.6%	0.3%	11.9%
Street Lighting	11.5%	0.3%	11.8%
Total Kentucky Power Jurisdiction	11.5%	3.1%	14.6%

The proposed allocations are described in more detail by Company Witness Coon.

**Q. IS LIMITING THE PROPOSED RATE INCREASE TO NO MORE THAN 15% FOR EACH CLASS REASONABLE?**

A. Yes. Although it is always the Company's goal to continue to make progress in reducing interclass subsidies and achieve cost-based rates, the Kentucky Power leadership team is keenly aware of the economic challenges throughout the service territory, specifically for residential customers. Therefore, at this point in time, it is more appropriate to allocate the revenue requirement more equally among the classes rather than attempting to eliminate



1 interclass subsidies at the expense of its residential customers or any other specific  
2 customer class.

**VI. PROPOSED CHANGES TO RESIDENTIAL RATE DESIGN**

3 **Q. PLEASE PROVIDE AN OVERVIEW OF THE PRINCIPALS THAT INFORMED**  
4 **THE CHANGES TO RATE DESIGN AND CUSTOMER OFFERINGS PROPOSED**  
5 **IN THIS PROCEEDING.**

6 A. Generally speaking, prior to filing this case the Company performed a detailed review of  
7 how rates and fixed charges were designed to see if any changes were warranted to address  
8 intraclass subsidies and better align the Company's costs with the basic principles of cost  
9 causation. As explained further below, the Company proposes a few changes to the fixed  
10 and variable cost components of customers rates in order to better align fixed charges with  
11 the fixed costs of service, and to more fairly and accurately assign costs to cost-causers.

12 First, the Company proposes to make an incremental increase to its customer charge  
13 in order to recover more fixed costs through that fixed rate component. The Company is  
14 continuing to follow the general principal of gradualism in its proposal to increase the  
15 customer charge for its average and low energy users, and therefore is not proposing to  
16 reflect the maximum level of customer charge supported by Company Witness Spaeth.  
17 Instead, the Company proposes a more modest, yet meaningful increase to the customer  
18 charge that is more in line with the actual fixed costs to serve customers.

19 Second, in order to address high winter and summer bills, the Company proposes a  
20 new residential rate design that includes a two-tiered customer charge and a two-block  
21 variable energy charge, which Company Witness Spaeth and I describe in more detail. This  
22 design shifts a greater amount of fixed costs from the variable energy charge to the fixed

1 customer charge for customers using more than 2,000 kWh in a month. This has the effect  
2 of reducing the variable energy rate and reflecting a variable energy rate that is more in  
3 line with the Company's actual variable costs. This will also reduce the intraclass subsidy  
4 currently provided by residential higher energy users, as under the current residential rate  
5 design, higher energy users contribute more to the Company's fixed costs given the  
6 significant amount of fixed costs recovered through the Company's current variable energy  
7 rate.

8 Third, the Company proposes to reflect the actual costs of performing services that  
9 customers pay for through existing special charges. The change the Company proposes to  
10 special charges will ensure that the customers requesting those services are responsible for  
11 the entirety of those costs, thereby reducing the cost-of-service for all other customers.

12 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO INCREASE THE**  
13 **RESIDENTIAL CUSTOMER CHARGE.**

14 A. The current residential service charge is \$20.00 per month. The Company calculated a  
15 residential customer-related unit cost of \$46.19 per month. Or said another way, the total  
16 residential customer-related revenue requirement of \$72.3 million divided by 1,564,142  
17 (the total number of annual residential bills) equals \$46.19 per month, as further detailed  
18 in Company Witness Spaeth's Direct Testimony. Company Witness J. Wolfram supports  
19 the zero-intercept study, which apportions certain distribution costs between the customer  
20 and demand classifications, and Company Witness Coon supports the class cost-of-service  
21 study, where the total customer-related cost is ultimately determined by class. Although  
22 the resulting customer-related unit cost supports a fairly significant increase to the

1 customer charge, the Company proposes to set its customer charge at a level lower than  
2 that supported by those analyses.

3 As discussed in detail by Company Witness Spaeth, the Company proposes a  
4 two-tiered structure where customers who consume between 0–2,000 kWh in a month will  
5 be charged the Tier 1 charge of \$26.00 per month, and customers who consume greater  
6 than 2,000 kWh in a month will be charged the Tier 2 charge of \$40.00 per month.

7 In addition, the two-tiered customer charge is designed to work hand-in-hand with  
8 the Company's proposed declining energy rates, where all customers are charged \$0.15750  
9 per kWh for the first 600 kWh of usage in a month and \$0.12606 for all usage in excess of  
10 600 kWh. In effect, as the customer's usage increases, the variable rates decline to account  
11 for recovery of more fixed costs through the higher customer charge, and through the  
12 higher variable rates at lower usage levels. In other words, as usage increases, the variable  
13 rates decrease to more closely align variable rates with variable costs. For lower energy  
14 users, the Company is still proposing to make progress toward including more fixed costs  
15 in those fixed charges, but through a smaller customer charge increase in order to more  
16 gradually increase recovery through that fixed cost component.

17 **Q. WHY IS IT REASONABLE AND APPROPRIATE TO STRUCTURE THE**  
18 **CUSTOMER CHARGE IN TWO TIERS BASED ON USAGE?**

19 A. The two-tiered customer charge, coupled with the declining energy rate, provide incentives  
20 to higher usage customers to lower their usage to under 2,000 kWh per month in order to  
21 receive the lower customer charge. At the same time, the Company recognizes that  
22 high-usage residential customers are currently subsidizing low-usage residential customers  
23 for some fixed-cost components of the Company's cost to serve, as current rates recover a

1 higher amount of fixed costs through the variable energy rate component. In order to  
2 address this issue, the Company proposes that higher-usage customers pay a higher  
3 customer charge, which more closely aligns the fixed cost component of their bills with  
4 their actual contribution to fixed costs. The proposed declining energy rate also allows the  
5 Company to provide higher-usage customers a lower variable rate for usage above 600  
6 kWh. As explained by Company Witness Spaeth, this rate design will significantly reduce  
7 bill volatility for customers using 2,000 kWh or more per month in the winter and summer  
8 months.

9 **Q. DID PRIOR COMMISSION PRECEDENT INFORM THE COMPANY'S**  
10 **DECISIONS IN EVALUATING POTENTIAL CHANGES TO ITS CUSTOMER**  
11 **CHARGE?**

12 A. Yes. The Company carefully considered this Commission's prior precedent, which  
13 encourages utilities to engage in rate design that makes progress toward aligning fixed  
14 costs with fixed charges.<sup>1</sup> The Commission also has previously required the Company to  
15 perform a zero-intercept study and expressed its preference for the use of a zero-intercept  
16 study for the purposes of determining the demand/customer expense allocations for the  
17 distribution plant classifications.<sup>2</sup> Further, in the Company's last base rate case, the  
18 Commission stated that, "the Commission expects Kentucky Power to address the issue of

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<sup>1</sup> See Order at 30, *In The Matter Of: Electronic Application Of Shelby Energy Cooperative, Inc. For A General Adjustment Of Rates*, Case No. 2024-00351 (Ky. P.S.C. July 23, 2025) ("The Commission has consistently found it reasonable to raise the consumer facility charge in utility rate cases to better reflect the fixed costs inherent in provided utility service. However, the Commission has also found it reasonable to embrace the principle of gradualism in ratemaking, which mitigates the financial impact of rate increases on customers while providing reasonable rates." (citations omitted)).

<sup>2</sup> Order at 53, 55, *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 Certification Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief*, Case No. 2020-00174, (Ky. P.S.C. Jan. 13, 2021).

low-income and residential customers [sic] energy usage during the winter months and find cost-effective measures to reduce demand.”<sup>3</sup> Each of these factors influenced and informed the Company’s rate design proposals in this case.

**Q. HAS THE COMPANY EMPLOYED OTHER MEASURES TO HELP ADDRESS HIGH USAGE FOR RESIDENTIAL CUSTOMERS SPECIFICALLY?**

A. Yes. As a result of the Commission’s final order in Case No. 2024-00115, the Company has implemented new demand-side management programs. Specifically, the Company expanded its Targeted Energy Efficiency Program and launched its new Home Energy Improvement Program, which is designed to increase weatherization and reduce energy inefficiencies for residential customers.

**VII. PROPOSED CHANGES TO SPECIAL CHARGES**

**Q. WHAT ARE SPECIAL CHARGES?**

A. Special charges are non-recurring charges for certain services that should logically be designed to recover the specific cost of that service from the customer(s) causing the cost.

**Q. PLEASE DESCRIBE THE COMPANY’S CURRENT SPECIAL CHARGES.**

A. Currently, the Company’s tariff includes special charges for: Reconnection and Disconnection or Field Trip, Meter Read Check, Returned Check Charge, Meter Test Charge, Delayed Payment Charge, Temporary Service Charge, and Energy Diversion Charge.

The Company last proposed changes to its special charges in its 2014 base rate case, Case No. 2014-00396, over 10 years ago. In that case, the amount of those charges were

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<sup>3</sup> Order at 70, *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, (Ky. P.S.C. Jan. 19, 2024).

1 agreed to as part of a Commission-approved settlement. Although part of a settlement, they  
2 were designed to reflect the actual costs to perform those services at that time. In the  
3 Company's 2020 base rate case, Case No. 2020-00174, the Commission held that certain  
4 special charges should reflect only the marginal costs to provide the service during normal  
5 working hours. Accordingly, the Commission reduced the Company's "reconnection fees  
6 during regular hours" and "termination or field trip charges" from \$21.00 and \$13.00 to  
7 \$4.70 and \$4.70, respectively.

8 **Q. IS THE COMPANY PROPOSING TO MODIFY SPECIAL CHARGES?**

9 A. Yes. The Company proposes to update the following special charges: (1) Reconnection and  
10 Disconnection or Field Trip, (2) Meter Read Check, (3) Returned Check Charge, and  
11 (4) Meter Test Charge. The Company completed an analysis of the costs to perform each  
12 of these activities and proposes certain changes to those special charges based on the results  
13 of that analysis. The Company is not proposing to change its current Delayed Payment  
14 Charges, Temporary Service Charge, or Energy Diversion Charge. The proposed special  
15 charges are reflected in Section II, Exhibits D and E, on Original Sheet 2-12. Please see  
16 Figure TSW-2 below for a summary of the proposed changes.

**Figure TSW-2**

<b>Special Charge</b>	<b>Current Rate</b>	<b>Proposed Rate</b>
Reconnect during regular hours for non-AMI meters	\$4.70	\$54.11
Reconnect at the end of the day (no “call out” required) for non-AMI meters	\$30.00	\$137.20
Reconnect prior to 8pm (“call out” required) for non-AMI meters	\$95.00	\$137.20
Reconnect when double time is required (Sundays and holidays) for non-AMI meters	\$124.00	\$178.75
Reconnect for meters with remote reconnection capability (AMI)	N/A	\$0
Termination or field trip	\$4.70	\$54.11
Meter Read Check	\$21.00	\$54.11
Returned Check Charge	\$14.65	\$6.60
Meter Test Charge	\$48.00	\$74.88

**Q. WHY IS MODIFICATION TO THESE CHARGES REASONABLE AND NECESSARY?**

A. There are numerous reasons why it is reasonable and necessary to modify the non-recurring special charges. First, as I describe further below, the deployment of Advanced Metering Infrastructure (“AMI”) in Kentucky Power’s service territory will have a substantial impact on the costs associated with reconnection and disconnection. Additionally, the current charges for Reconnection and Disconnection associated with non-AMI customers, as well as Field Trip, Meter Read Check Charge, Returned Check Charge, and Meter Test Charge do not collect the actual costs to perform those services. Specific to Reconnection and Disconnection or Field Trips during normal hours, the Company’s current charges do not collect the actual costs of the work performed because they are currently based on marginal costs, not on the actual cost, to perform those services. Finally, the following costs of service are not currently being collected entirely from the cost-causer, as the Company’s

1 current special charges for these services have not been updated since its 2014 base rate  
2 case: (1) Reconnection at the end of the day where no call-out is required; (2) Reconnection  
3 where a weekday call-out is required; (3) Reconnection where the call out requires  
4 overtime and Sunday or holiday call-out; (4) Meter Read Check Charge; (5) Returned  
5 Check Charge; and (6) Meter Test Charge. Therefore, at least a portion of the actual costs  
6 to perform those services is being socialized to other customers who did not request those  
7 services.

8 It is more appropriate from a cost causation perspective to allocate the costs of those  
9 nonrecurring services to the actual cost-causers and to eliminate the subsidy from  
10 customers who do not receive those services. For example, customers with AMI meters  
11 should not be responsible for costs incurred to physically reconnect or disconnect  
12 customers, because there is virtually no cost to the Company when these services are  
13 provided to AMI customers remotely.

14 **Q. HAVE THERE BEEN MATERIAL CHANGES TO THE COMPANY'S**  
15 **OPERATIONS THAT IMPACT THE MARGINAL COST ANALYSIS**  
16 **PREVIOUSLY USED BY THE COMMISSION IN SETTING SPECIAL**  
17 **CHARGES?**

18 A. Yes. As approved in Case No. 2024-00344, the Company is beginning to deploy AMI  
19 technology throughout its service territory. The new AMI meters will have remote  
20 reconnect and disconnect capabilities, meaning the Company will not have to send  
21 personnel out to physically reconnect or disconnect meters once AMI is installed. As such,  
22 all trips to customer premises become incremental to work that distribution employees  
23 would otherwise be performing. Thus, it is appropriate to reflect the actual costs of these



1 services for non-AMI customers in special charges to align with the principles of cost  
 2 causation. This is also consistent with the Commission’s Order in Case No. 2020-00349,  
 3 where Louisville Gas & Electric Company and Kentucky Utilities Company were approved  
 4 to charge special and non-recurring rates that aligned with the actual costs to perform such  
 5 non-recurring services as a result of AMI.<sup>4</sup>

6 **Q. HOW WERE THE PROPOSED RECONNECTION AND DISCONNECTION**  
 7 **CHARGES DETERMINED?**

8 A. First, based on the Commission’s approval of the Company’s request to deploy AMI meters  
 9 in Case No. 2024-00344, the Company proposes to set Reconnection and Disconnection  
 10 fees for AMI customers to \$0. This is consistent with the Commission’s final order in that  
 11 case, which made clear that the Company should create a plan for reducing the frequency  
 12 and amount of its tariffed non-recurring charges concurrent with AMI deployment.<sup>5</sup> Given  
 13 the remote reconnection capabilities of AMI, the Company is not required to send an  
 14 employee to a customer’s premises to manually reconnect the meter, and it therefore incurs  
 15 virtually no actual cost to do so.

16 The same is not the case for non-AMI customers. The Company used data and  
 17 information supplied by field employees and their supervisors to determine the average  
 18 time to perform different activities associated with disconnection and reconnection of

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<sup>4</sup> Order at 50, *In The Matter Of: Electronic Application Of Kentucky Utilities Company For An Adjustment Of Its Electric Rates, A Certificate Of Public Convenience And Necessity To Deploy Advanced Metering Infrastructure, Approval Of Certain Regulatory And Accounting Treatments, And Establishment Of A One-Year Surcredit*, Case No. 2020-00349, (Ky. P.S.C. June 30, 2021) (“Due to the phasing out of disconnect/reconnect charges as AMI meters are deployed and KU’s use of employee and contract labor to perform these services, the Commission has chosen not to remove labor from the disconnect/reconnect charge.”).

<sup>5</sup> Order at 22, *In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A Certificate Of Public Convenience And Necessity Authorizing The Deployment Of Advanced Metering Infrastructure; (2) Request For Accounting Treatment; And (3) All Other Necessary Waivers, Approvals, And Relief*, Case No. 2024-00344, (Ky. P.S.C. July 22, 2025).

1 non-AMI meters. The Company then aggregated the total labor costs, transportation costs,  
2 fringe benefit costs, and any other associated costs to arrive at the total cost to perform  
3 each of the different activities listed on Exhibit TSW-1. For example, for Reconnection  
4 requiring a call-out at night, on weekends, or on holidays, the minimum hours that can be  
5 logged by the worker is two hours. Therefore, the cost of Reconnection varies from \$54.11  
6 during regular hours, to \$137.20 for a weekday call-out or where the call out requires  
7 overtime (at the end of the day), and to \$178.75 for a Sunday or holiday call-out, which  
8 requires payment of double time.

9 **Q. HOW WERE THE REMAINING PROPOSED SPECIAL CHARGES**  
10 **DETERMINED?**

11 A. The Company performed a similar analysis as that described above (for non-AMI  
12 Reconnection/Disconnection) to determine the actual cost to perform services that make  
13 up the remaining special charges. Please also see Exhibit TSW-1 for an analysis of the  
14 various labor costs, transportation costs, fringe benefit, and other associated costs incurred  
15 by the Company for each of those services. I describe the proposed special charges for the  
16 remaining services and why they are reasonable below.

17 **Q. HOW WAS THE PROPOSED METER TEST CHARGE DETERMINED?**

18 A. Upon written request by the customer, the Company will test the meter for accuracy. Based  
19 upon the Company's analysis, the Company determined that it incurs a cost of \$74.88 for  
20 each test. The Company therefore proposes that amount as the reasonable charge for Meter  
21 Test Charge.

**Q. HOW WAS THE PROPOSED RETURNED CHECK CHARGE DETERMINED?**

A. When a customer pays their monthly bill with a check that is subsequently returned, there are associated bank fees assessed to the Company in the amount of \$6.60. The Company therefore proposes that amount as the reasonable charge for Returned Check Charge.

**Q. HOW WAS THE PROPOSED METER READ CHECK CHARGE DETERMINED?**

A. When a customer requests that a meter be re-read, and the second reading shows the original reading was correct, there are labor and other costs involved in the testing. The Company views this similarly to the normal Termination or Field Trip special charge because the Meter Read Check takes a similar amount of time and does not require any additional equipment as compared to the Meter Test Charge. As such, based upon the Company's analysis, the Company determined that it incurs a cost of \$54.11 for this service. The Company therefore proposes that amount as the reasonable charge for Meter Read Check Charge.

**Q. WHAT ADJUSTMENT TO THE ANNUAL REVENUE REQUIREMENT DOES THE COMPANY PROPOSE TO EFFECTUATE THESE MODIFIED SPECIAL CHARGES?**

A. If the proposed changes to special charges were in effect for the 12 months ending December 31, 2024, and the number of transactions for each activity remained the same, the Company's special charges revenue would have increased by \$643,148. The Company recovered \$238,329 of special charge revenue during the test year. As such, I am sponsoring Adjustment W6 to increase Other Operating Revenue to a going level of \$881,476.77 (\$238,329 test-year amount + \$643,148). The \$643,148 increase to Other

Operating Revenue is a credit to cost-of-service and ultimately reduces the Company's revenue deficiency.

### **VIII. GENERATION RIDER**

**Q. PLEASE PROVIDE AN OVERVIEW OF KENTUCKY POWER'S INTEREST IN THE MITCHELL PLANT.**

A. Currently, the Company's interest in the energy and capacity from the Mitchell Plant is set to terminate on December 31, 2028.<sup>6</sup> However, the Company filed an application in Case No. 2025-00175<sup>7</sup> for a CPCN and all other required regulatory approvals to extend its interest in the energy and capacity from the Mitchell Plant beyond December 31, 2028. That case is currently pending before this Commission.

Notwithstanding the outcome of that case, the Company has evaluated ways to best address the recovery of the Company's remaining net book value of the Mitchell Plant, which totals approximately \$537 million as of May 31, 2025. Of the \$537 million remaining net book value of the Mitchell Plant as of May 31, 2025, approximately \$388 million is recoverable through the Company's environmental surcharge,<sup>8</sup> approximately \$22 million related to asset retirement costs has historically been recovered by including a level of depreciation expense in the Company's base rate cost-of-service, and

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<sup>6</sup> See Order at 7, *In The Matter Of: Electronic Application Of Kentucky Power Company For Approval Of A Certificate Of Public Convenience And Necessity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets*, Case No. 2021-00004 (Ky. P.S.C. May 3, 2022); Order at 13, *In The Matter Of: Electronic Application Of Kentucky Power Company For Approval Of Affiliate Agreements Related To The Mitchell Generating Station*, Case No. 2021-00421 (Ky. P.S.C. May 3, 2022).

<sup>7</sup> Application, *In The Matter Of: Electronic Application Of Kentucky Power Company For Approval Of (1) A Certificate Of Public Convenience And Necessity To Make The Capital Investments Necessary To Continue Taking Capacity And Energy From The Mitchell Generating Station After December 31, 2028, (2) An Amended Environmental Compliance Plan, (3) Revised Environmental Surcharge Tariff Sheets, And (4) All Other Required Approvals And Relief*, Case No. 2025-00175 (Ky. P.S.C. June 30, 2025).

<sup>8</sup> Composed of approximately \$160 million related to Mitchell FGD and \$228 million related to Mitchell Non-FGD.

1 approximately \$127 million related to non-environmental investment has historically been  
2 recovered through the Company's base rate revenue requirement. The proposed Generation  
3 Rider is intended to address recovery of the remaining net book value of the Company's  
4 non-environmental investment at the Mitchell Plant, as I explain further below.

5 **Q. WHAT COSTS ARE PROPOSED TO BE RECOVERED THROUGH THE**  
6 **GENERATION RIDER AND WHAT ADJUSTMENTS DO YOU SUPPORT IN**  
7 **ORDER TO ACCOMPLISH THAT RECOVERY?**

8 A. The proposed Generation Rider is designed to recover the revenue requirement related to  
9 \$127 million of non-environmental Mitchell Plant capital plant balances that have  
10 historically been recovered through base rates, plus the \$60.4 million of non-Effluent  
11 Limitations Guidelines Rule ("ELG") capital that the Company will be responsible to pay  
12 should the Commission approve the Company's pending application in Case  
13 No. 2025-00175.

14 However, given that the Company's application in Case No. 2025-00175 is still  
15 pending, the Company has not included that \$60.4 million in the initial Generation Rider  
16 revenue requirement requested to be approved in this case. As discussed further below, the  
17 Company is instead requesting authority to defer the non-environmental annual revenue  
18 requirement related to the \$60.4 million of non-ELG capital to a regulatory asset until it  
19 can be reflected in rates.

20 As such, the initial revenue requirement for the Generation Rider is set to recover  
21 only the non-environmental Mitchell Plant plant balances on the Company's books as of  
22 May 31, 2025, contained in Adjustment W49.

1 **Q. ARE YOU SPONSORING ANY ADJUSTMENTS ASSOCIATED WITH THE \$60.4**  
2 **MILLION OF NON ELG CAPITAL?**

3 A. Yes. I am supporting an adjustment to rate base, Adjustment W51-A, to include the \$60.4  
4 million of non-ELG capital. Adjustment W51-B then immediately adjusts that amount back  
5 out of rate base consistent with the Company's proposal to recover the related revenue  
6 requirement beginning on the date capital is invested and plant is recorded on the  
7 Company's books through the Generation Rider, if the Company is approved to recover  
8 those costs in Case No. 2025-00175.

9 **Q. WHY IS ADJUSTMENT W51A-B NECESSARY IF THE COMPANY PROPOSES**  
10 **TO RECOVER THE \$60.4 MILLION THROUGH THE GENERATION RIDER IN**  
11 **THE FUTURE?**

12 A. If the Company's proposal to create the Generation Rider is not approved, but the  
13 Company's application in Case No. 2025-00175 is approved, then Adjustment W51-B  
14 would need to be reversed, but Adjustment W51-A to include the \$60.4 million of non-  
15 ELG capital in rate base would still need to be made in order to reflect the Company's full  
16 50% share of the Mitchell Plant costs to continue Kentucky Power's interest in the plant  
17 after 2028.

18 Further, should the Company's proposal to create the Generation Rider be denied,  
19 Adjustment W49 to remove the Mitchell Plant non-environmental plant balances as of May  
20 31, 2025 would need to be reversed to keep those amounts in base rates going forward.

1 **Q. ARE THERE MITCHELL PLANT-RELATED COSTS THAT WILL REMAIN IN**  
2 **BASE RATES AND THAT WILL NOT BE RECOVERED THROUGH THE**  
3 **GENERATION RIDER?**

4 A. Yes. The base revenue requirement for the environmental surcharge, as discussed by  
5 Company Witness Cullop, will remain in base rates to avoid confusion and unnecessary  
6 complexity in calculating the revenue requirement for the proposed Generation Rider.

7 Ongoing operations and maintenance expense (“O&M”) for plant operations will  
8 also continue to be collected through already existing mechanisms. The environmental  
9 O&M related to items approved for recovery in Tariff Environmental Surcharge (“Tariff  
10 E.S.”) will remain in Tariff E.S., and the amounts approved for recovery through base rates  
11 will continue to be collected through base rates. Finally, accumulated deferred income tax  
12 (“ADIT”) related to the Mitchell Plant balances will continue to be reflected in existing  
13 mechanisms (*i.e.*, the Company will continue to reflect ADIT for the environmental plant  
14 through the environmental surcharge and the non-environmental ADIT will remain in base  
15 rates).

16 **Q. PLEASE EXPLAIN WHY RIDER RECOVERY FOR THE**  
17 **NON-ENVIRONMENTAL MITCHELL PLANT CAPITAL IS APPROPRIATE.**

18 A. As I explained in my Direct Testimony in Case No. 2025-00175, the Company is  
19 continuing to pursue securitization legislation that would allow it to securitize the  
20 remaining net book value of the Mitchell Plant, including the investments proposed to be  
21 approved in that application. In order to most efficiently effectuate securitization, the  
22 Company proposes to remove all non-environmental Mitchell Plant capital plant from base  
23 rates and instead collect those costs through the new Generation Rider. Accordingly, if

1 securitization occurs, collection of those costs through the rider can cease without having  
2 to file another base rate case.

3 **Q. ARE THERE OTHER FACTORS THAT SUPPORT RIDER RECOVERY FOR**  
4 **THE MITCHELL PLANT CAPITAL?**

5 A. Yes. The Generation Rider also provides the benefit of updating and reflecting the actual  
6 undepreciated plant balance on an annual basis. Under the current ratemaking framework,  
7 customers only see the effects of a reduced plant balance when the Company files its base  
8 rate cases, which historically has occurred every two to three years. With the proposed  
9 Generation Rider, the Company will update and reflect a reduced plant balance each year  
10 as the asset is being depreciated.

11 Further, given that the Company is committed to seeking securitization of the  
12 remaining net book value of the Mitchell Plant, and the currently-pending application in  
13 Case No. 2025-00175, the Company also made the decision not to update the depreciation  
14 rates for the Mitchell Plant at this time. That decision results in a roughly \$11 million  
15 reduction to the Company's cost-of-service in this proceeding.

16 **Q. IS THE DECISION TO PROPOSE A NEW RIDER IN ANTICIPATION OF NEW**  
17 **SECURITIZATION LEGISLATION BASED ON ANY FEEDBACK FROM**  
18 **STAKEHOLDERS?**

19 A. Yes. After the Company's last securitization application in Case No. 2023-00159, various  
20 legislators and customers provided feedback to the Company that it would have been better  
21 to seek a securitization financing order from this Commission outside of a base rate case.  
22 Given that the Company is committed to seeking new securitization legislation for the  
23 Mitchell Plant in order to provide savings to customers, it would be much more efficient



1 to have the amounts to be securitized in a rider mechanism so that once the securitization  
2 bonds are issued, the Company could cease collection of the securitized cost without  
3 having to file a base rate case.

4 **Q. HOW WOULD SECURITIZATION AFFECT THE MITCHELL PLANT COSTS**  
5 **CURRENTLY RECOVERED THROUGH THE ENVIRONMENTAL**  
6 **SURCHARGE?**

7 A. The environmental surcharge calculates the monthly total environmental costs approved  
8 for recovery and then deducts the base environmental revenue requirement authorized for  
9 collection in base rates. However, if securitization of these costs were approved, those  
10 amounts would be removed from recovery through the environmental surcharge, but still  
11 reduce the total by the base environmental revenue requirement (*i.e.*, crediting customers  
12 the amounts of environmental plant that are included in base rates). Notably, this same  
13 concept was employed for Rockport-related environmental costs after the Rockport Unit  
14 Power Agreement expired in December 2022 and until the Company could remove these  
15 costs from base rates as part of its next base rate case (Case No. 2023-00159).

16 **Q. PLEASE DESCRIBE HOW THE COMPANY PROPOSES TO RECOVER COSTS**  
17 **THROUGH THE GENERATION RIDER.**

18 A. The rider is designed to mimic, as closely as possible, recovery of the non-environmental  
19 plant as if it were to be collected in base rates, as it is currently. Accordingly, customers  
20 will have either have a (a) per kWh factor or (b) per kW factor. Please see Exhibit TSW-2  
21 for the rate design and Exhibit TSW-3 for the proposed Generation Rider Tariff.

1 **Q. HOW OFTEN DOES THE COMPANY PROPOSE TO UPDATE THE**  
2 **GENERATION RIDER RATE?**

3 A. After initially setting the rate as part of this proceeding, which would be effective March  
4 1, 2026, the Company proposes to true-up the Generation Rider annually by February 15  
5 each year, to be effective beginning with April billing.

6 **Q. WHAT IS THE PROPOSED INITIAL ANNUAL REVENUE REQUIREMENT**  
7 **FOR THE GENERATION RIDER?**

8 A. The initial annual revenue requirement for the new Generation Rider will be approximately  
9 \$20.3 million. The Company is requesting that the Generation Rider include an annual  
10 true-up, with the annual true-up amount to be included in the Company's proposed annual  
11 February filing, resulting in recovery of any under-collection during the prior year period  
12 or credit for any over-collection during the period. Company Witness Ciborek discusses  
13 the Company's corresponding request for deferral accounting authority for the Generation  
14 Rider, so that it can account for any over or under recovery monthly.

15 To the extent the Company's currently pending CPCN application is approved and  
16 the Generation Rider is approved, the Company would make a filing to begin recovering  
17 the non-environmental annual revenue requirement related to the \$60.4 million of  
18 non-ELG capital and related regulatory asset balance.

19 **Q. IS THE COMPANY REQUESTING ANY OTHER ACCOUNTING TREATMENT**  
20 **RELATED TO THE BALANCES PROPOSED TO BE INCLUDED IN THE**  
21 **GENERATION RIDER?**

22 A. Yes. As explained above, given that the Company's application in Case No. 2025-00175  
23 is still pending, the Company has not included the \$60.4 million of non-ELG capital being

1 reviewed in that case in its initial Generation Rider revenue requirement. Should that  
2 application be approved, the Company expects there will be a delay between investment of  
3 that capital and when recovery will begin. To address this expected timing difference, the  
4 Company requests authority to defer to a regulatory asset that amount of the  
5 Non-Environmental Mitchell Annual Revenue Requirement<sup>9</sup> invested but not yet  
6 recovered in rates, beginning on the date capital is invested and recorded on the Company's  
7 books, and ending on the date that begin being reflected in rates. The Company would  
8 recover this regulatory asset through a subsequent update to the Generation Rider. Should  
9 the Generation Rider not be approved, the Company would request to recover this  
10 regulatory asset in a future rate proceeding.

#### **IX. PROPOSALS TO MODIFY EXISTING TARIFFS**

11 **Q. WHAT MODIFICATIONS TO EXISTING TARIFFS ARE YOU SUPPORTING?**

12 A. I am sponsoring modifications to the Company's existing Tariff P.P.A. and Tariff F.T.C.

13 First, the Company proposes to modify Tariff P.P.A. to provide for the collection  
14 or credit of any gains and losses on incidental sales of gas procured for natural gas  
15 generation, which I explain in further detail below. The Company also proposes to remove  
16 Rockport-related items from recovery through Tariff P.P.A. considering that those amounts  
17 were securitized in June 2025, and that the Capacity Credit amounts have been fully  
18 recovered.

19 Second, the Company also proposes to modify Tariff F.T.C. to create a line-item  
20 for the net operating loss carryforward ("NOLC") regulatory asset established in  
21 accordance with the Commission's January 19, 2024 Order in Case No. 2023-00159.

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<sup>9</sup> As defined in and calculated consistent with the Company's proposed Tariff Generation Rider.

1 Finally, while the Company does not propose to modify the Decommissioning  
2 Rider (“D.R.”) as part of this case, the proposals in the Company’s most recent annual  
3 filing for that rider necessitate modifications to the cost-of-service in this case. Specifically,  
4 on August 15, 2025, the Company filed its annual D.R. update to reinstate that rider  
5 mechanism. Tariff D.R. was initially suspended as a result of the Commission’s Order in  
6 Case No. 2023-00159 while securitization was pending. Post securitization, the Company  
7 has incurred additional costs associated with asset retirement obligations (“ARO”) related  
8 to the retired Big Sandy coal facilities. The Company’s annual filing proposed to resume  
9 recovery of those AROs through Tariff D.R. As such, Company Witness Ciborek has  
10 removed those coal-related ARO costs from the Company’s cost-of-service to allow  
11 recovery through Tariff D.R.

**Gains and Losses on Incidental Gas Sales (Tariff P.P.A.)**

**Q. WHAT ARE GAINS AND LOSSES ON INCIDENTAL SALES OF GAS?**

12 A. As explained in further detail by Company Witness Stutler, the Company enters into  
13 fixed-price, forward-month contracts for the supply of gas for generation. From time to  
14 time, a plant is unable to burn the gas that has been purchased due to real-time dispatch  
15 decisions by PJM or because of operational issues such as a forced outage. During those  
16 periods where the Company has excess gas available on the pipeline, its current practice is  
17 to liquidate its position on the pipeline. The sale can result in either a gain or loss on the  
18 price the Company paid for that gas depending on market conditions at the time.  
19

1   **Q.     PLEASE PROVIDE AN OVERVIEW OF THE PROPOSED CHANGE TO TARIFF**  
2       **P.P.A. RELATED TO THE GAINS AND LOSSES ON INCIDENTAL SALES OF**  
3       **GAS.**

4   A.    The Company does not currently have a mechanism to pass back any gains or collect any  
5       losses on sales of gas. As such, the Company proposes to set a base amount for incidental  
6       sales of gas (based on the amount of gains and losses experienced during the test year) and  
7       then perform annual over-/under-recovery accounting on the base level of sales of gas  
8       approved in this case and collect or credit that difference through Tariff P.P.A. This allows  
9       the Company to recover or credit the difference between the base amount and the amounts  
10      actually realized from such sales so that customers pay no more and no less than that  
11      actually realized.

12               Specifically, the over/under calculation will track the amounts of these sales  
13      throughout the year as compared to the base amount set in this proceeding, and in each of  
14      the Company's subsequent annual Tariff P.P.A. updates, the Company will seek to recover  
15      any losses above the base amount or credit back to customers the difference between the  
16      base amount and the actual amount of sales incurred during the year if it is less than the  
17      base rate amount. The base amount proposed to be set in this proceeding is roughly \$1.9  
18      million, which is the actual amount of the losses on incidental sales of gas that the Company  
19      experienced during the test year. Any gains and losses from these incidental sales will be  
20      included with other purchase power-related costs as part of the calculation of the annual  
21      P.P.A. factor.

1   **Q.   WHY IS TARIFF P.P.A. THE APPROPRIATE MECHANISM THROUGH**  
2       **WHICH TO COLLECT LOSSES OR CREDIT GAINS ON INCIDENTAL SALES**  
3       **OF GAS?**

4   A.   These amounts are appropriate for collection through a rider like Tariff P.P.A. because they  
5       can be volatile and are largely outside the Company's control. Specifically, as explained  
6       further by Company Witness Stutler, there has been significant volatility in the natural gas  
7       market in recent years that directly impacts the amount of the gains or losses the Company  
8       experiences on its incidental sales of natural gas. Further, the resulting gain or loss may  
9       also be driven by forced outages, maintenance outages or extensions of planned outages,  
10      and market economics of PJM's real time operation.

11           Further, the Company generally has two mechanisms through which it currently  
12      recovers fuel costs: the fuel adjustment clause and Tariff P.P.A. I understand that gains or  
13      losses on incidental sales of gas do not appear to be eligible for recovery through the fuel  
14      adjustment clause. However, Tariff P.P.A. currently provides for the recovery of the cost  
15      of fuel to substitute generation, less the cost of fuel that would have been used in plants  
16      suffering a forced generation or transmission outage. This is similar to the situation the  
17      Company proposes to address here. As such, Tariff P.P.A. is the most appropriate existing  
18      mechanism to effectuate recovery of losses or to credit gains resulting from gas sales.

19   **Q.   IS THIS PROPOSAL REASONABLE, NECESSARY, AND IN CUSTOMERS'**  
20       **INTEREST?**

21   A.   Yes. The proposal to track the actual amounts of incidental sales through Tariff P.P.A.  
22       ensures customers are responsible only for the actual costs the Company incurs to secure  
23       natural gas for use at its generating facilities. As explained further by Company Witness

1 Stutler, the Company appropriately hedges its gas position to mitigate impacts caused by  
2 variability in the commodities market. However, given the instances described above and  
3 by Company Witness Stutler, it is sometimes unavoidable for the Company to sell surplus  
4 gas in order to abide by pipeline balancing requirements. As such, it also is appropriate to  
5 have a mechanism to share any gains or to recover the difference between what the  
6 Company paid for the gas and what it sold for. Otherwise, the Company would be  
7 positioned to retain any gains on sales in years where gas was resold at a surplus or would  
8 be left to weather the impacts of surplus gas sold at a loss.

**NOLC Regulatory Asset (Tariff F.T.C.)**

9 **Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE FEDERAL TAX CUT**  
10 **TARIFF.**

11 A. In the Company's last base rate case proceeding, Case No. 2023-00159, the Commission  
12 approved the Company to defer the revenue requirement related to the NOLC ADIT to a  
13 regulatory asset with recovery contingent on Kentucky Power receiving a Private Letter  
14 Ruling ("PLR") from the Internal Revenue Service ("IRS") that affirms the Company's  
15 position regarding the NOLC ADIT. Given the Commission's order in that case, the  
16 Company proposes to modify the Tariff F.T.C. upon receipt of a PLR to allow recovery of  
17 the regulatory asset associated with the NOLC ADIT.

18 **Q. HAS THE COMPANY RECEIVED A PLR FROM THE IRS AS OF THIS FILING?**

19 A. Not at this time. However, given the other PLRs that sister companies have received in  
20 which the Internal Revenue Service affirmed those companies' analysis of the applicable  
21 tax law, the Company wants to ensure it has established the associated recovery mechanism  
22 to effectuate the PLR in accordance with IRS guidance. Company Witness Hodgson

1 explains the expectations for recovery of the NOLC based on a new PLR that makes rider  
2 recover necessary.

**X. DEFERRAL REQUESTS AND ACCOUNTING TREATMENT**

3 **Q. ARE YOU PROPOSING ANY DEFERRALS FOR ANY OF THE PROGRAMS OR**  
4 **TEST-YEAR AMOUNTS IN THIS PROCEEDING?**

5 A. Yes. I am sponsoring two deferral requests in this case, in addition to the deferral request  
6 associated with the Generation Rider. First, the Company seeks authority to defer the  
7 test-year amount of losses on sales of gas for inclusion in its next annual Tariff P.P.A. filing  
8 consistent with the proposed changes to Tariff P.P.A. Second, I am supporting deferral of  
9 the costs associated with implementing the FlexPay Program that is supported by Company  
10 Witness Cobern.

11 **Q. PLEASE EXPLAIN THE DEFERRAL RELATED TO THE INCIDENTAL GAINS**  
12 **AND LOSSES ON SALES OF GAS.**

13 A. As explained by Company Witness Stutler, the Company incurred roughly \$1.9 million of  
14 losses on its incidental sales of gas during the test year. As explained above, the Company  
15 currently does not have a mechanism to recover these test-year costs incurred to provide  
16 service to customers, as these amounts do not appear to be eligible for recovery through  
17 the fuel adjustment clause or any other existing mechanism. As such, the Company requests  
18 authority to defer the test-year amount and the amounts incurred post-test-year until the  
19 next Tariff P.P.A. annual update, of losses on the incidental sale of gas, and proposes to  
20 amortize and collect that amount through Tariff P.P.A. in its next annual Tariff P.P.A.  
21 filing.



1 **Q. PLEASE EXPLAIN THE PROPOSED DEFERRAL OF FLEXPAY PROGRAM**  
 2 **COSTS.**

3 A. The Company expects to incur roughly \$75,000 to develop the FlexPay offering proposed  
 4 in this case. The Company does not expect FlexPay to be available for customers until the  
 5 third quarter of 2026 based on the current AMI deployment schedule. Rather than include  
 6 those costs in the test year now, the Company seeks to defer those amounts to be recovered  
 7 in a subsequent base rate case after AMI has been deployed.

8 **Q. WHY IS A DEFERRAL APPROPRIATE FOR EACH OF THESE ITEMS?**

9 A. For the request to defer actual losses on incidental sales of gas during the test year, those  
 10 costs are extraordinary and non-recurring expenses that the Company could not have  
 11 reasonably anticipated. The amount of those losses are tied to PJM market economics and  
 12 volatility within the gas supply market, generally, and are based on outages the Company  
 13 cannot reasonably predict. Therefore, deferral authority is appropriate and should be  
 14 granted.

15 For the request to defer FlexPay program costs, the Commission approved the  
 16 Company's application for AMI deployment in Case No. 2024-00344,<sup>10</sup> and in the final  
 17 order in that case, the Commission made clear that it expects the Company to pursue all  
 18 reasonable and cost effective programs, including adding prepay programs, made possible  
 19 by AMI.<sup>11</sup> The Commission also approved the Company's requested deferral treatment of  
 20 for AMI deployment in that case. Given that the Company seeks to meet the Commission's

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<sup>10</sup> Order at 21, *In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A Certificate Of Public Convenience And Necessity Authorizing The Deployment Of Advanced Metering Infrastructure; (2) Request For Accounting Treatment; And (3) All Other Necessary Waivers, Approvals, And Relief*, Case No. 2024-00344, (Ky. P.S.C. July 22, 2025).

<sup>11</sup> *Id.* at 15.

directives to pursue all reasonable programs to fully enhance the benefits of AMI by proposing to create a prepay program to be available once AMI deployment begins, deferral of the costs required to accomplish the FlexPay offering is appropriate.

## **XI. STORM EXPENSE ADJUSTMENT**

### **Storm Damage Expense** **(Section V, Exhibit 2, W21)**

**Q. PLEASE EXPLAIN HOW KENTUCKY POWER HAS TRADITIONALLY SET A NORMALIZED LEVEL OF STORM EXPENSE FOR BASE RATES PRIOR TO ITS MOST RECENT BASE RATE CASE (CASE NO. 2023-00159 (“2023 RATE CASE”)).**

A. Prior to the Company’s 2023 Rate Case, Kentucky Power adjusted its test-year distribution major storm damage expense by using a historical three-year average of distribution major storm damage expenses, excluding in-house labor, and then adjusting by the Handy-Whitman Contract Labor Index.<sup>12</sup> The Company included the actual, unadjusted test-year level of distribution non-major storm damage expense, as well as the actual level of test-year transmission major and non-major storm damage expense.

**Q. PLEASE EXPLAIN HOW THE METHODOLOGY FOR STORM NORMALIZATION WAS MODIFIED IN THE 2023 RATE CASE.**

A. In the 2023 Rate Case, Kentucky Power proposed, and the Commission approved, to change the previously-used methodology by (a) reducing the level of total distribution major and non-major storm project expense in the test year to approximately \$1.0 million,

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<sup>12</sup> The Handy-Whitman Index is a publication that is released semi-annually on January 1 and July 1, tracking construction costs for public utilities. It is published by Whitman, Requardt and Associates, with a specific focus on the electric utility industry. The index is used to escalate costs for various projects, particularly in the electric power sector. It serves multiple purposes, such as adjusting costs for future periods in long-term projects, determining the value of utility assets like dams, and predicting future transmission costs for electrical energy systems.

1 and (b) maintaining the actual test-year level of transmission major and non-major storm  
2 project expense of \$0.1 million.

3 **Q. WHAT LEVEL OF STORM EXPENSE DID KENTUCKY POWER INCUR**  
4 **DURING THE TEST YEAR IN THIS CASE?**

5 A. During the test year, Kentucky Power incurred approximately \$23 million in storm  
6 expense. This amount includes those costs that the Company was approved to defer in  
7 various applications requesting to establish regulatory assets.

8 **Q. IF THE COMPANY USED THE STORM EXPENSE NORMALIZATION**  
9 **APPROACH THAT IT USED PRIOR TO THE 2023 RATE CASE, WHAT LEVEL**  
10 **OF STORM EXPENSE WOULD IT PROPOSE TO BE INCLUDED IN BASE**  
11 **RATES?**

12 A. If the Company adjusted its test-year distribution major storm damage expense by using a  
13 historical three-year average of distribution major storm damage expenses, excluding  
14 in-house labor, and then adjusted by the Handy-Whitman Contract Labor Index, the level  
15 of storm expense to be included in base rates would be \$13.5 million.

16 Even using a historical five-year average, the level of storm expense to be included  
17 in base rates would be approximately \$8.7 million.

18 **Q. WHAT LEVEL OF STORM EXPENSE DOES THE COMPANY PROPOSE TO**  
19 **INCLUDE IN BASE RATES IN THIS CASE?**

20 A. In an effort to mitigate customer rate impact, the Company proposes to adjust its test-year  
21 distribution storm damage expense to \$0. To accomplish that, the Company started with its  
22 per books test-year storm damage cost of approximately \$23.0 million and removed the  
23 approximately \$23.2 million of current deferrals associated with those events. This results

1 in a total test-year amount of storm expense of (\$215,408). The Company then increased  
2 its test-year storm damage expense by \$215,408 as shown Adjustment W21 in order to set  
3 the amount of expense to \$0.

4 **Q. HOW WILL THE COMPANY OTHERWISE RECOVER STORM EXPENSE IF**  
5 **STORM EXPENSE IN BASE RATES IS SET TO \$0?**

6 A. The Company proposes that, going forward, it be approved for accounting purposes only  
7 to establish regulatory assets for all storm costs incurred without the requirement to seek  
8 prior authority from the Commission to record the regulatory asset. The Company would  
9 also make quarterly updates to the Commission on detailing any such “automatic” storm  
10 deferral activity. It is important to note, as stated above, that the request to record deferrals  
11 without pre-approval is for accounting purposes only, meaning that the Company will still  
12 need to support the reasonableness and prudence of the costs at the time it seeks recovery.

13 **Q. HOW WOULD THE COMPANY PROPOSE TO AMORTIZE AND COLLECT**  
14 **THOSE DEFERRED COSTS?**

15 A. With respect to future recovery of storm regulatory assets, as Company Witness Wiseman  
16 also explains, the Company is actively engaged with state legislators and other interested  
17 stakeholders to pass legislation allowing securitization of additional utility regulatory  
18 assets. The Company’s previous application to securitize a significant amount of costs,  
19 made as part of Case No. 2023-00159, included the securitization of several storm  
20 regulatory assets and was successful in allowing those costs to be paid for by customers  
21 over a longer period of time, thereby bringing immediate rate relief to customers.  
22 Therefore, if additional securitization legislation is passed, the Company would propose to  
23 securitize all existing storm regulatory assets, including those created consistent with the

1        automatic deferral mechanism described above. If securitization does not occur, the  
2        Company would propose to amortize and recover the storm costs comprising those  
3        regulatory assets as part of its next base rate case or as part of another appropriate  
4        proceeding before this Commission.

5        **Q.    WHY IS IT REASONABLE AND APPROPRIATE TO SET STORM EXPENSE**  
6        **TO \$0?**

7        A.    While the Company acknowledges that it will certainly incur storm costs going forward,  
8        including storm expense in base rates in this case would have increased the Company's  
9        revenue requirement by over \$13 million using its traditional three-year average approach,  
10       or by nearly \$9 million using as five-year average approach. The Company closely  
11       reviewed the requests in this case for viable opportunities to reduce the requested annual  
12       revenue requirement increase. The proposed adjustment to set the amount of storm expense  
13       in base rates to \$0, in combination with the automatic deferral mechanism, is a creative  
14       way to balance the impact of the requested rate increase with the Company's present  
15       financial needs on a short-term basis. It also sets up those costs to be securitized, if such  
16       legislation is passed, which brings further rate relief to customers. Importantly, the proposal  
17       to set storm expense to \$0 is reasonable and workable if it is approved in conjunction with  
18       the proposed automatic deferral mechanism.

1 **Q. THE COMPANY HAS FILED MULTIPLE STORM DEFERRAL APPLICATIONS**  
2 **WITH THE COMMISSION SINCE ITS LAST BASE RATE CASE. DOES THE**  
3 **COMPANY PROPOSE TO RECOVER THOSE REGULATORY ASSETS IN THIS**  
4 **CASE?**

5 A. No. Although the Company's typical practice has been to amortize the regulatory assets  
6 approved in its deferral applications over a five-year period in past base rate cases, the  
7 Company instead proposes here, as another cost mitigation measure, to not seek  
8 amortization of those regulatory assets in this proceeding. If new securitization legislation  
9 is approved and those regulatory assets are eligible to be securitized as I just described, the  
10 Company could lower the associated impacts on customers' bills. If securitization does not  
11 occur, the Company will seek to amortize and recover those existing and any new storm  
12 regulatory assets in the Company's next base rate case or other appropriate proceeding.

13 **Q. PLEASE DESCRIBE THE ADJUSTMENT NECESSARY TO REFLECT NOT**  
14 **AMORTIZING THE EXISTING STORM REGULATORY ASSETS AT THIS**  
15 **TIME.**

16 A. I am sponsoring Adjustment W22 in order to accomplish this cost mitigation effort. The  
17 adjustment shows the current deferral amounts of \$23.3 million, inclusive of the deferral  
18 application for the May 16–17, 2025 Major Event Storms currently pending in Case No.  
19 2025-00264. The adjustment does not assign an amortization period so that the amount in  
20 the test-year cost-of-service is reflected as \$0.

**XII. RATE MAKING ADJUSTMENTS****Public Service Commission of Kentucky Maintenance Assessment  
(Section V, Exhibit 2, W40)**

1   **Q.   PLEASE EXPLAIN THE PURPOSE OF THE ADJUSTMENT TO TEST-YEAR**  
2       **LEVEL OF PUBLIC SERVICE COMMISSION MAINTENANCE ASSESSMENT**  
3       **AND WHY IT IS REASONABLE AND NECESSARY.**

4   **A.**   This adjustment simply adjusts the test-year amount of Public Service Commission of  
5       Kentucky Maintenance Fee expense in the cost-of-service to the actual current assessment  
6       amount, received July 1, 2025. This results in an increase to the test-year level of \$114,529.

**Ongoing Level of Non-F.A.C. Eligible Purchase Power Expense  
(Section V, Exhibit 2, W45)**

7   **Q.   PLEASE EXPLAIN THE PURPOSE OF THE ADJUSTMENT TO SET THE**  
8       **ONGOING LEVEL OF NON-F.A.C. ELIGIBLE PURCHASED POWER EXPENSE**  
9       **AND WHY IT IS REASONABLE AND NECESSARY.**

10   **A.**   The purpose of this adjustment is to reflect the test-year level of purchased power expense  
11       not eligible for recovery through the fuel adjustment clause. The peaking unit equivalent  
12       caps the amount of purchased power expense to be recovered in the Company's monthly  
13       Fuel Adjustment Clause Tariff ("Tariff F.A.C.") surcharge. As part of the  
14       Commission-approved the settlement agreement in the Company's most recent two-year  
15       F.A.C. review, Case No. 2023-00008, the Company now calculates the startup cost  
16       component of the peaking unit equivalent using \$4.62/MWh instead of the previously-  
17       approved \$30/MWh. This change reduces the peaking unit equivalent threshold for  
18       determining whether certain fuel costs are eligible for F.A.C recovery. Thus, in all months  
19       in the test year that used the new startup cost amount established in Case No. 2023-00008,  
20       the Company incurred additional non-F.A.C. eligible costs.

1           The total non-F.A.C. eligible purchased power expense recorded in the test year  
2 ended May 31, 2025, was \$9,341,868. The Company recalculated the months where the  
3 \$30/MWh for startup costs were used in the test year (June 2024 through December 2024)  
4 to identify the amount of non-F.A.C. eligible costs the Company would have incurred using  
5 \$4.62/MWh as the startup cost. This results in an adjustment to increase test-year expense  
6 by \$1,212,198 to establish the test-year level of non-F.A.C. eligible purchased power  
7 expense in the test year of \$10,554,065.16. This adjustment is directly assigned to the  
8 Company's retail jurisdiction.

**Turbine Reservation Fee**  
**(Section V, Exhibit 2, W52)**

9   **Q.   PLEASE EXPLAIN THE PURPOSE OF THE ADJUSTMENT FOR THE**  
10 **TURBINE RESERVATION FEE AND WHY IT IS REASONABLE AND**  
11 **NECESSARY.**

12   **A.**   On July 22, 2025, the Company contracted to reserve two combustion turbines for a new  
13 450 MW combustion turbine ("CT") that the Company plans to build at the existing Big  
14 Sandy Plant site. The reservation fee was \$10 million. The Company proposes to add this  
15 balance to rate base. The Company intends to submit an application for a CPCN and all  
16 other necessary regulatory approvals by the end of the first quarter of 2026 for the new 450  
17 MW CT. It is important to provide for recovery of the reservation fee amounts now so that  
18 the Company is well-positioned to move forward with construction of the new facility.

**XIII. CONCLUSION**

19 **Q.   DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

20 **A.**   Yes, it does.



## VERIFICATION

The undersigned, Tanner S. Wolfram, being duly sworn, deposes and says he is the Directory of Regulatory Services for Kentucky 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.

  
Tanner S. Wolfram

Commonwealth of Kentucky )  
                                                  )  
County of Boyd )

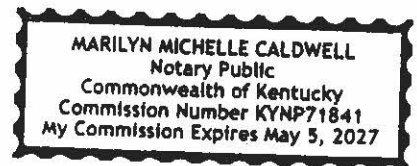
Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tanner S. Wolfram, on August 25, 2025.

  
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841



Misc. Non-recurring charges

Description of Charge	Standard charge amount	Account	Actual Cost
<b>Reconnection</b>			
Reconnect for nonpayment during regular hours	\$ 4.70	4510001	\$ 54.11
Reconnect at the end of the day (no "call out")	\$ 30.00	4510001	\$ 137.20
Reconnect for nonpayment prior to 8pm ("call out" required)	\$ 95.00	4510001	\$ 137.20
Reconnect for nonpayment when double time is required (Sundays and holidays)	\$ 124.00	4510001	\$ 178.75
<b>Termination or field trip</b>			
	\$ 4.70	4510001	\$ 54.11
<b>Meter Read Check</b>			
	\$ 21.00	4510001	\$ 54.11
<b>Returned Check Charge</b>			
	\$ 14.65	4510001	\$ 6.60
<b>Meter Test Charge</b>			
	\$ 48.00	4510001	\$ 74.88
<b>Delayed Payment Charge</b>			
	5% of unpaid balance	4500000	
<b>Temporary Service Charge</b>			
	*variable	4510001	
<b>Energy Diversion</b>			
	actual cost	4510001	

\*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.

12  
(Ln 6 + Ln 8 + Ln 10+Ln 11)

GL Unit	Eff Date	Act Fringe Rate	Act CIP fringe
103	3/31/2025	34	11.3
110	3/31/2025	39.42	11.3
114	3/31/2025	37.83	11.3
117	3/31/2025	57.05	11.3
119	3/31/2025	39.16	11.3
120	3/31/2025	35.8	11.3
132	3/31/2025	40.18	11.3
140	3/31/2025	40.29	11.3
150	3/31/2025	35.84	11.3
159	3/31/2025	37.28	11.3
160	3/31/2025	35.86	11.3
161	3/31/2025	38.41	11.3
167	3/31/2025	37.32	11.3
168	3/31/2025	35.86	11.3
169	3/31/2025	38.71	11.3
170	3/31/2025	37.22	11.3
180	3/31/2025	35.78	11.3
190	3/31/2025	32.29	11.3
192	3/31/2025	34.35	11.3
194	3/31/2025	39.71	11.3
198	3/31/2025	36.63	11.3
210	3/31/2025	41.39	11.3
211	3/31/2025	39.78	11.3
215	3/31/2025	37.74	11.3
230	3/31/2025	40.05	11.3
250	3/31/2025	37.36	11.3
270	3/31/2025	69.87	11.3
400	3/31/2025	30.25	11.3
413	3/31/2025	38.03	11.3
474	3/31/2025	36.61	11.3

<b>Field Revenue Specialist</b>	<b>Reconnect Regular Hours</b>
<b>Hourly Rate</b>	29.8
<b>Overtime</b>	14.9
<b>2024 Fleet Cost Per Hour</b>	12.56
<b>Rate Used</b>	100.00%

**KENTUCKY POWER COMPANY**  
**Estimated Generation Rider Annual Revenue Requirement**

Ln. No.	Cost Component	Mitchell Non- Environmental
1	Utility Plant at Original Cost	\$ 327,699,888
2	Less Accumulated Depreciation	\$ 200,045,017
3	Less Accumulated Deferred Income Tax	\$ -
4	Net Utility Plant	<b>\$ 127,654,871</b>
5	Construction Work in Progress (CWIP)	\$ -
6	<b>Total Rate Base</b>	<b>\$ 127,654,871</b>
7	WACC for Capital Riders	9.14%
8	Return on Capital	\$ 11,667,655
9	<b>Return on Capital</b>	<b>\$ 11,667,655</b>
10	Annual Depreciation Expense	\$ 8,425,896
11	Annual Property Tax	\$ 195,008
12	<b>Annual Other Expense</b>	<b>\$ 8,620,904</b>
13	Annual Other Expenses	<b>\$ 8,620,904</b>
14	Other Expenses During TY	\$ 8,620,904
15	Difference in Test Year O&M & Current O&M	\$ -
16	<b>Gross-up for Uncollectible Expense &amp; KPSC Maint Fee</b>	<b>\$ -</b>
17	<b>Annual Revenue Requirement</b>	<b>\$ 20,288,559</b>

Generation Rider - Form 2.0

**Kentucky Power Company  
Generation Rider Rate Design**

KY Retail Jurisdiction Revenue Requirement¹		Demand	Energy	Total
		\$20,288,559	\$0	\$20,288,559

Class (1)	Billing Energy (2)	Billing Demand (3)	Test Year CP / kWh Ratio (4)	CP Demand Allocation Factor (5) = (2) x (4)	Allocated Demand Related Costs (6) on (5)	Allocated Energy Related Costs (7) on (2)	\$ / kW Rate (8) = (6) / (3)	\$ / kWh Rate (9) = (7) / (2)	Revenue Verification (10)	Difference (11) = (10) - (6) - (7)
RES	1,889,849,939		0.0222735%	420,936	\$9,795,969		\$0	\$0.00519 ²	\$9,808,321	\$12,352
GS (SGS/MGS)	616,305,297		0.0174606%	107,610	2,504,286		0	\$0.00406	2,502,200	-\$2,086
LGS	469,816,215	1,443,014	0.0151572%	71,211	1,657,213		0	\$0.00000	1,659,466	\$2,253
LGS LMTOD	878,955		0.0151572%	133	3,095		0	\$0.00352	3,094	-\$1
IGS	2,293,390,283	3,851,549	0.0117865%	270,311	6,290,643		0	\$0.00000	6,278,025	-\$12,618
MW	1,831,694		0.0114684%	210	4,887		0	\$0.00267	4,891	\$4
OL	30,809,971		0.0036139%	1,113	25,902		0	\$0.00084	25,880	-\$22
SL	7,836,986		0.0035948%	282	6,563		0	\$0.00084	6,583	\$20
Total	5,310,719,340	5,294,563		871,806	\$20,288,558		\$0		\$20,288,460	(\$98)

KENTUCKY POWER COMPANY

P.S.C. KY. NO. 14 ORIGINAL SHEET NO. 32-1  
CANCELLING P.S.C. KY. NO. 13 ORIGINAL SHEET NO. 32-1**Tariff G.R.  
(Generation Rider)**

N

**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**

The annual Generation Rider factor will be computed using the following formula:

$$\text{Non-Environmental Mitchell Annual Revenue Requirement (ARR)} = (\text{RB} + \text{CWIP})(\text{ROR}) + \text{DE} + \text{PT} + \text{OU}$$

Where:

- RB = Non-Environmental Rate Base for Mitchell represented by the sum of plant in service less accumulated depreciation;
- CWIP = Construction Work in Progress for Non-Environmental Mitchell Projects;
- ROR = Rate of Return on Non-Environmental Mitchell Rate Base;
- DE = Depreciation Expense;
- PT = Property Taxes;
- OU = Cumulative difference between revenues received and actual costs for the reporting period, representing the (over) or under recovery.

**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.	\$0.00519	--
S.G.S.-T.O.D.	\$0.00406	--
M.G.S.-T.O.D.	\$0.00406	--
G.S.	\$0.00406	--
L.G.S., L.G.S.-T.O.D.	--	\$1.15
L.G.S.-L.M.-T.O.D.	\$0.00352	--
I.G.S. and C.S.-I.R.P.	--	\$1.63
M.W.	\$0.00267	--
O.L.	\$0.00084	--
S.L.	\$0.00084	--

I

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.

*Continued on Sheet 32-2*

DATE OF ISSUE: August 29, 2025  
DATE EFFECTIVE: Services Rendered On And After March 1, 2026  
ISSUED BY: /s/ Tanner S. Wolfram  
TITLE: Director, Regulatory Services  
By Authority of an Order of the Public Service Commission  
In Case No.: 2025-00257 Dated XXXX XX, XXXX



## Tariff G.R. Continued (Generation Rider)

N

The Generation Rider factors shall be modified annually using the following formula:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{\text{GR(E)} \times (\text{BE}_{\text{Class}} / \text{BE}_{\text{Total}}) + \text{GR(D)} \times (\text{CP}_{\text{Class}} / \text{CP}_{\text{Total}})}{\text{BE}_{\text{Class}}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{\text{GR(E)} \times (\text{BE}_{\text{Class}} / \text{BE}_{\text{Total}})}{\text{BE}_{\text{Class}}}$$

$$\text{kW Factor} = \frac{\text{GR(D)} \times (\text{CP}_{\text{Class}} / \text{CP}_{\text{Total}})}{\text{BD}_{\text{Class}}}$$

Where:

1. “GR(D)” is the actual annual retail GR demand-related costs.
2. “GR(E)” is the actual annual retail GR energy-related costs.
3. “BE<sub>Class</sub>” is the forecasted annual retail jurisdictional billing kWh for each tariff class for the current year.
4. “BD<sub>Class</sub>” is the forecasted annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. “CP<sub>Class</sub>” is the coincident peak demand for each tariff class estimated as follows:

*Continued on Sheet 32-3*

DATE OF ISSUE: August 29, 2025  
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TITLE: Director, Regulatory Services,  
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In Case No.: 2025-00257 Dated XXXX XX, XXXX

**Tariff G.R. Continued  
(Generation Rider)**

N

Tariff Class	BE <sub>Class</sub>	CP/kWh Ratio	CP <sub>Class</sub>
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.022274%	
S.G.S.-T.O.D.		0.017461%	
M.G.S.-T.O.D.		0.017461%	
G.S.		0.017461%	
L.G.S., L.G.S.-T.O.D.		0.015157%	
L.G.S.-L.M.-T.O.D.		0.015157%	
I.G.S. and C.S.-I.R.P.		0.011787%	
M.W.		0.011468%	
O.L.		0.003614%	
S.L.		0.003595%	

6. "BE<sub>Total</sub>" is the sum of the BE Class for all tariff classes.
7. "CP<sub>Total</sub>" 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 0.28% and the KPSC Maintenance Fee of 0.1595% and other similar revenue based taxes or assessments occasioned by the Generation Rider revenues.
9. The annual GR factors shall be filed with the Commission by February 15 of each year based on prior calendar year, with rates to begin with the April 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.
10. 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.

D

DATE OF ISSUE: August 29, 2025  
DATE EFFECTIVE: Services Rendered On And After March 1, 2026  
ISSUED BY: /s/ Tanner S. Wolfram  
TITLE: Director, Regulatory Services  
By Authority of an Order of the Public Service Commission  
In Case No.: 2025-00257 Dated XXXX XX, XXXX

**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 Certain Regulatory And Accounting )  
Treatments; and (4) All Other Required Approvals )  
And Relief )

Case No. 2025-00257

## DIRECT TESTIMONY OF

MICHELE ROSS

**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
MICHELE ROSS ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT MR-1	Map of Kentucky Power Service Territory
EXHIBIT MR-2	Map of Kentucky Power Vegetation Density
EXHIBIT MR-3	Jackson, KY National Weather Service Historical Data
EXHIBIT MR-4	TOR Reliability Widening Workplan

**DIRECT TESTIMONY OF  
MICHELE ROSS ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is Michele Ross. My business address is 1645 Winchester Avenue, Ashland,  
3       Kentucky 41101. I am the Vice President of Distribution Region Operations for Kentucky  
4       Power Company (“Kentucky Power” or “the Company”).

**II. BACKGROUND**

5   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
6       **BUSINESS EXPERIENCE.**

7   A.   I earned a Bachelor of Science degree in Psychology from Ohio State University in 1993  
8       and my Journeyman Certificate from the American Electric Power (“AEP”)   
9       Underground/Network Apprenticeship Program in 2003. I began my utility career in 1994  
10      as a meter reader for AEP Ohio and progressed through various levels of increasing  
11      responsibility within the distribution organization. Throughout my career, I led field crews  
12      in the installation, repair, and restoration of electric equipment, served as a Safety and  
13      Health Coordinator, Distribution Supervisor, Distribution Manager overseeing overhead  
14      distribution, design and meter operations and Distribution Dispatch Manager. Prior to my  
15      current role, I was the Director of Operations for AEP Ohio. I was promoted to my current  
16      position in July 2024.

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

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

### **III. PURPOSE OF TESTIMONY**

10 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
11 **PROCEEDING?**

12 A. The purpose of my Direct Testimony is to:

- 13 • Provide an overview of the Company's service territory, distribution system, and  
14 operational challenges to providing safe and reliable service to customers;
- 15 • Describe the Company's reliability indices and performance;
- 16 • Describe and support the Company's distribution reliability programs, including the  
17 Company's proposed expansion of its trees outside the right-of-way ("TOR") and trees  
18 inside the right-of-way ("TIR") programs;
- 19 • Describe and support the reasonableness of the distribution capital investments the  
20 Company has made since its last base rate case;
- 21 • Support the test-year level of distribution operation and maintenance ("O&M")  
22 expense;

- Address the Company’s Advanced Metering Infrastructure (“AMI”) plan; and
- Provide details on the Company’s Smart Grid investments.

**Q. ARE YOU SPONSORING ANY EXHIBITS?**

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

<u>Exhibit</u>	<u>Description</u>
Exhibit MR-1	Map of Kentucky Power Service Territory
Exhibit MR-2	Map of Kentucky Power Vegetation Density
Exhibit MR-3	Jackson, KY National Weather Service Historical Data
Exhibit MR-4	TOR Reliability Widening Workplan

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

A. Yes.

#### **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 162,000 retail customers in Kentucky, in a service area that covers approximately 3,800 square miles. Kentucky Power’s distribution system includes 229 distribution circuits, approximately 9,900 miles of primary and secondary overhead distribution lines, and approximately 187 miles of primary and secondary underground distribution lines. The Company’s 10,156 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,

1 the Company's distribution system consists largely of long 34.5 kV and 12.47 kV circuits,  
2 that average 47.8 and 40.9 miles in length, respectively, with the longest circuit covering  
3 173 primary circuit miles. A map of Kentucky Power's service territory is attached hereto  
4 as Exhibit MR-1.

5 **Q. PLEASE DESCRIBE THE OPERATIONAL CHALLENGES ASSOCIATED WITH**  
6 **THE COMPANY'S SERVICE TERRITORY.**

7 A. Kentucky Power's service territory is located in a rural and densely forested part of  
8 Kentucky, which provides operating challenges not experienced by other investor-owned  
9 utilities in the Commonwealth. Specifically, the major challenges associated with  
10 Kentucky Power's territory include:

11 **Terrain:** The Company's service territory consists of mountainous terrain that includes  
12 steep, rocky, heavily forested hill sides, and narrow valleys that constrain access to the  
13 transmission and distribution facilities. The challenging terrain complicates damage  
14 assessment, mobilization of materials and labor, and repair efforts, leading to longer  
15 customer outage restoration times.

16 **Vegetation Density:** Approximately 75% of Kentucky Power's overhead primary miles  
17 are exposed to vegetative risk and threat of interruption due to one or both trees outside of  
18 rights-of-way ("TOR") and trees inside of rights-of-way ("TIR") causes. Please see Exhibit  
19 MR-2 for a map of the vegetation density in the Company's territory. The forests consist  
20 of mostly large, mature trees that experience natural tree mortalities. Since these trees are  
21 larger and heavier, when they do fall, even when outside the right-of-way, they cause  
22 severe damage to the Company's distribution assets, such as broken poles, cross arms, and  
23 conductors.



1       **Rainfall:** Average rainfall for the past several years is generally increasing from the  
2       30-year average. Increased rainfall beyond local averages poses significant challenges for  
3       electric utilities due to tree-related failures. The stability of soil and the topography of the  
4       Company's service territory are key factors, as greater surface runoff, elevated waterways,  
5       and more frequent flooding events lead to soil erosion along and adjacent to Company  
6       rights-of-way. This erosion weakens the ground's ability to support trees, while increased  
7       sub-surface water movements can cause landslides, further impacting these areas.  
8       Persistently high soil moisture levels around root zones, driven by greater rainfall,  
9       contribute to wet roots that are prone to rotting, thus diminishing tree stability. Trees that  
10      are leaning or have canopies extending beyond their centers are particularly vulnerable, as  
11      they struggle to anchor in the soft and repeatedly saturated soils. Additionally, trees in the  
12      region are generally conditioned to withstand wind speeds up to roughly 45 mph. However,  
13      the frequency of severe storms with winds exceeding this threshold has increased,  
14      compounding the risks of tree instability and failure that threaten the reliability of the  
15      Company's distribution system.

16             As shown in Exhibit MR-3, precipitation data from the National Weather Service  
17      for Jackson, Kentucky for the years of 1981 to 2010 shows a monthly average rainfall of  
18      4.03 inches per month, or an annual average of 48.34 inches of rainfall. By contrast, the  
19      average annual precipitation for the most recent five-year period (2020-2024) was 52.30  
20      inches.

21      **Operational-Long Circuits Lengths, 34.5 kV Circuits:** Due to the rural nature of the  
22      Company's service territory, the Company has long circuit lines and fewer customers per  
23      mile of primary distribution than other Kentucky investor-owned utilities ("IOUs"). For

example, the Company has approximately 16 customers per distribution line mile. This is significantly lower than the Company's IOU peers in Kentucky that vary 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 outages 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 have 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 33 circuits that have no three-phase connection to another circuit or limitations from circuit step-down transformers. When customers on these circuits experience an outage, they must wait for the line section to be restored because the circuits do not have an alternative power source, or the Company must back feed the line section by using portable generators.

#### **V. 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"), and Customer Minutes of Interruption ("CMI"). These metric data are analyzed for historical trends by area and outage cause, which ultimately are used in planning the Company's 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 12-month basis. Kentucky Power considers SAIFI to be a general indicator of the condition of an electric system under most circumstances.

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 that were interrupted. Kentucky Power measures CAIDI in minutes on a rolling 12-month basis. Kentucky Power considers CAIDI to be a general indicator of response and recovery performance when sustained outages occur.

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 12-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.

**Q. WHAT IS THE DEFINITION OF MAJOR EVENT DAY AND WHY ARE THEY GENERALLY EXCLUDED FROM SYSTEM RELIABILITY REPORTING?**

A. IEEE 1366-2022, 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 those normally expected (such as severe weather).” MEDs are typically excluded from the calculation of these industry standard metrics to better represent system performance during normal conditions and associated tracking of improvement, and to allow for more consistent comparisons with other utilities and industry averages.

**Q. HOW DOES THE COMPANY CALCULATE TMED?**

A. The Company calculates TMED using the standard IEEE formula:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

Where  $\alpha$  is the average of  $\text{Ln}(\text{SAIDI})$  and  $\beta$  is the standard deviation of  $\text{Ln}(\text{SAIDI})$ , and SAIDI is comprised of the sum of SAIDI for the past five sequential years. “Ln” stands for Natural Logarithm.

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

A. The Company’s three-year rolling average for SAIFI, CAIDI, and SAIDI indices since 2012 are shown in Figure MR-1.

**Figure MR-1 – SAIFI, SAIDI, and CAIDI Performance Indices (excluding MEDs)**

<b>Year</b>	<b>3-Yr SAIFI Average</b>	<b>3-Yr CAIDI Average</b>	<b>3-Yr SAIDI Average</b>
2012	2.66	184.8	493.1
2013	2.55	187.8	481.2
2014	2.31	193.6	448.7
2015	2.33	193.7	452.0
2016	2.34	202.8	473.1
2017	2.27	194.3	440.1
2018	2.23	199.9	445.4
2019	2.33	196.4	458.5
2020	2.28	199.9	455.5
2021	2.12	203.3	428.2
2022	2.05	209.7	430.0
2023	2.00	203.7	408.2
2024	2.10	193.6	409.4

Since 2012, Kentucky Power has demonstrated the ability to consistently drive customer reliability in a positive direction. Though there are anomalies, the indices indicate a continued trend of metric improvement when analyzing indices on a rolling three-year average.

**Q. WHAT ARE THE MOST TYPICAL TYPES OF OUTAGE CAUSES THAT IMPACT THE COMPANY’S RELIABILITY METRICS ABOVE?**

A. Please see Figure MR-2 for a breakdown of the most impactful outage causes in 2024. The top eight outage causes illustrated in the figure below represent approximately 94% of Kentucky Power’s total CMI for 2024.

**Figure MR-2 – Percent of 2024 CMI by Cause**

<b>Outage Cause</b>	<b>Percent of 2024 CMI</b>	<b>2024 CMI</b>
Trees Outside of Right-of-Way	55.39%	36,324,190
Equipment Failure	15.32%	10,044,529
Scheduled Company	6.77%	4,441,685
Vehicle Accident (Non-AEP)	4.64%	3,040,593
Unknown (Non-Weather)	4.42%	2,895,925
Weather - Unknown	3.33%	2,184,305
Tree Inside of Right-of-Way	2.11%	1,381,654
Weather - High Winds (Exceeding 60mph)	2.06%	1,353,606
All Other Causes (31 unique causes)	5.96%	3,917,927

## **VI. 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 and continually improve 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.

**Distribution Asset Management**

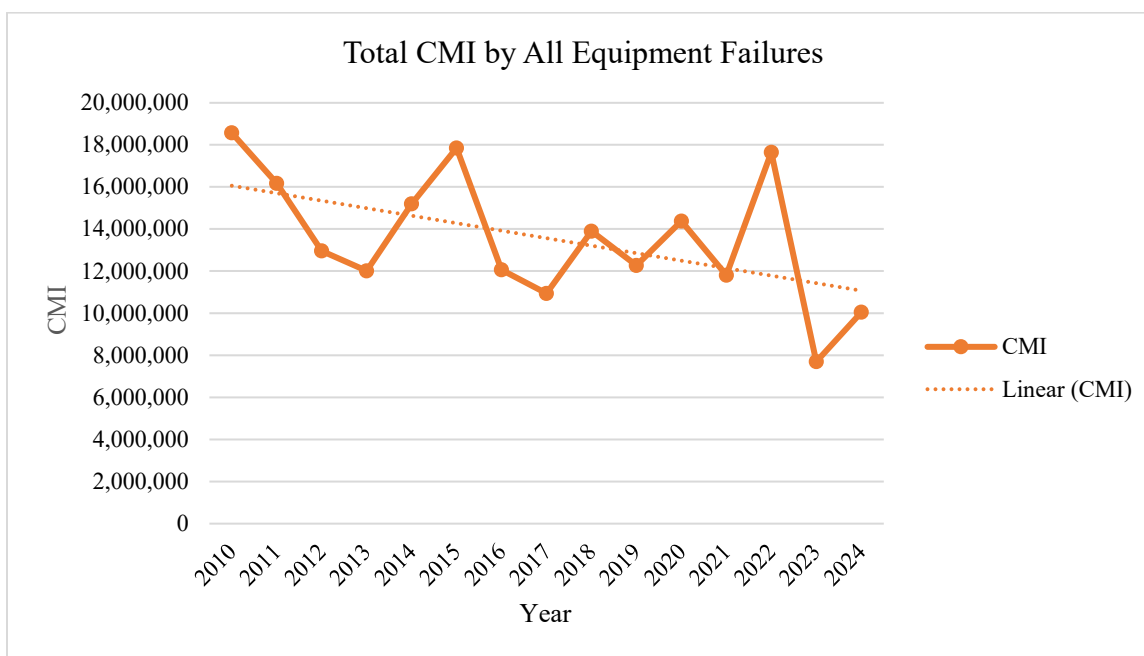
1 **Q. PLEASE DESCRIBE KENTUCKY POWER'S DISTRIBUTION ASSET**  
2 **MANAGEMENT PROGRAMS.**

3 A. The following Distribution Asset Management Programs are designed to replace assets  
4 prior to equipment failure, which accounts for approximately 15% of the Company's CMI,  
5 in order to maximize the efficiency of expenditures and optimize system performance:

- 6 1) Overhead Circuit and Underground Facilities Inspection and Maintenance  
7 Program;
- 8 2) Capacitor and Regulator Inspection and Maintenance Program;
- 9 3) Recloser Maintenance/Replacement Program;
- 10 4) Sectionalizing Program; and
- 11 5) Overhead Conductor Program.

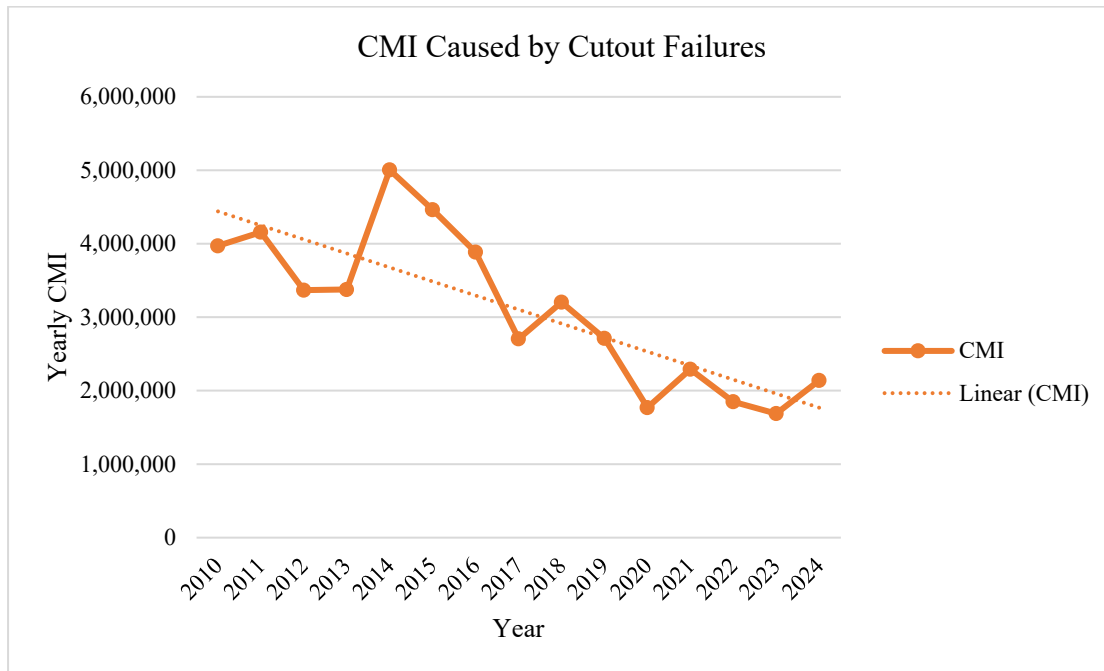
12 **Q. PLEASE PROVIDE DETAILS ON THE RELIABILITY BENEFITS THAT THE**  
13 **COMPANY'S CUSTOMERS RECEIVE THROUGH EXECUTION OF THESE**  
14 **PROGRAMS.**

15 A. As shown by the trendline in Figure MR-3, historic weather events in 2022 aside,  
16 equipment failures since 2020 have generally been trending progressively downward.

**Figure MR-3 – Trendline of Equipment Failures**

1           The Company actively monitors equipment failures by reviewing historical outage  
2           data. For example, over the past 15 years (2010–2024) cutouts were the leading cause of  
3           equipment failures. A fused cutout provides overcurrent protection for primary line  
4           sections, safeguarding the system from currents resulting from line faults, equipment  
5           failures, or system overloads. The Company has targeted cutouts, achieving a 45%  
6           reduction in CMI as illustrated in Figure MR-4.



**Figure MR-4 – Trendline of Cutout Failures**

Since 2008, insulator failures have been the second leading equipment failure cause of CMI across the Company's distribution system. The purpose of distribution insulators is to physically support system conductors while insulating, or protecting, surrounding objects and distribution equipment from conductive voltage. The 2008–2024 average CMI due to insulator failures was approximately 2.44 million. In 2022 specifically, insulator failures were the leading cause of equipment failure outages resulting in approximately 4.6 million CMI. The Company directly addressed insulator failures and reduced the 2024 CMI amount by approximately 18% from the 2008–2024 average.

#### **Major Distribution Reliability and Capacity Additions**

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

**A.** Each year, including the test year in this case, Kentucky Power performs various activities to improve the reliability of the distribution system and improve its performance for

1 customers. These investments include the TOR Program and asset renewal. I discuss the  
2 Company's plans for TOR in more detail later in my Direct Testimony. The asset renewal  
3 program is comprised of various activities like circuit and pole inspections, as well as the  
4 replacement of poles, reclosers, and cutouts. To improve circuit coordination and system  
5 resiliency, the Company is installing protective devices such as fuses and reclosers. This  
6 allows circuits to more efficiently isolate line faults, effectively shortening circuit zones  
7 and mitigating the volume of customer impact when an outage occurs. Kentucky Power is  
8 investing in grid intelligence technologies like Distribution Automation in order to enable  
9 remote switching. Finally, the Company is building additional line-ties to provide alternate  
10 sources and switching capabilities to shorten the duration of outages. New distribution  
11 construction, such as the equipment installed to facilitate the line ties, is built to the  
12 National Electric Safety Code ("NESC") heavy-loading criteria. Due to the increasing  
13 volume and severity of weather events, Kentucky Power constructs all new distribution  
14 assets to the heavy-loading standard despite the service territory being located in a  
15 medium-loading zone according to the NESC. The hardening of the distribution system  
16 through this loading standard will improve system resilience during major storm events,  
17 aiding in withstanding the impacts of severe weather. No amount of hardening will prevent  
18 an outage if a tree falls into the system. However, the TOR Program, in conjunction with  
19 asset renewal and grid hardening, will improve reliability performance.

20 The Company's capacity planning efforts proactively identify areas where the  
21 expected demand for electricity is approaching the limit of the distribution system's current  
22 capacity. The reliability improvement projects are necessary to serve load growth and  
23 upgrade, improve, or effectively maintain the Company's distribution system. These

1 projects either re-conductor the existing feeders or allow portions of the existing  
2 distribution system to be reconfigured. The expansion of the distribution system to serve  
3 new customers can also result in the upgrade or replacement of distribution facilities to  
4 maintain and enhance reliable service to the Company's existing customers.

**Kentucky Power's Distribution Vegetation Management Program**

5 **Q. WHAT PROGRAMS DOES KENTUCKY POWER UTILIZE AS A PART OF ITS**  
6 **VEGETATION MANAGEMENT?**

7 A. Kentucky Power's Vegetation Management Program includes two major components.  
8 These components are: (1) the TIR Program, a five-year cycle-based program that targets  
9 trees and vines in the Company rights-of-way, and (2) the TOR Program, widening the  
10 existing rights-of-way, and identifying and removing danger trees. Systematic and  
11 complete vegetation management programs are widely utilized by the utility industry as an  
12 effective way to reduce the frequency and duration of vegetation related outages.

13 **Q. PLEASE DETAIL KENTUCKY POWER'S INVESTMENTS IN THE TIR**  
14 **PROGRAM AND TOR PROGRAM.**

15 A. Since 2017, Kentucky Power has invested over \$229 million in these two vegetation  
16 management programs. See Figure MR-5 for vegetation spend year-over-year by project  
17 for each program.

**Figure MR-5 – Vegetation Management Investments**

<b>Year</b>	<b>TIR</b>	<b>TOR</b>
2017	\$27,840,992	\$0
2018	\$21,779,501	\$5,800,828
2019	\$21,303,373	\$11,291,140
2020	\$21,347,446	\$8,477,187
2021	\$21,847,587	\$6,843,116
2022	\$21,599,427	\$6,694,133
2023	\$21,491,040	\$6,731,375
2024	\$22,217,123	\$4,631,694

**TIR Program**

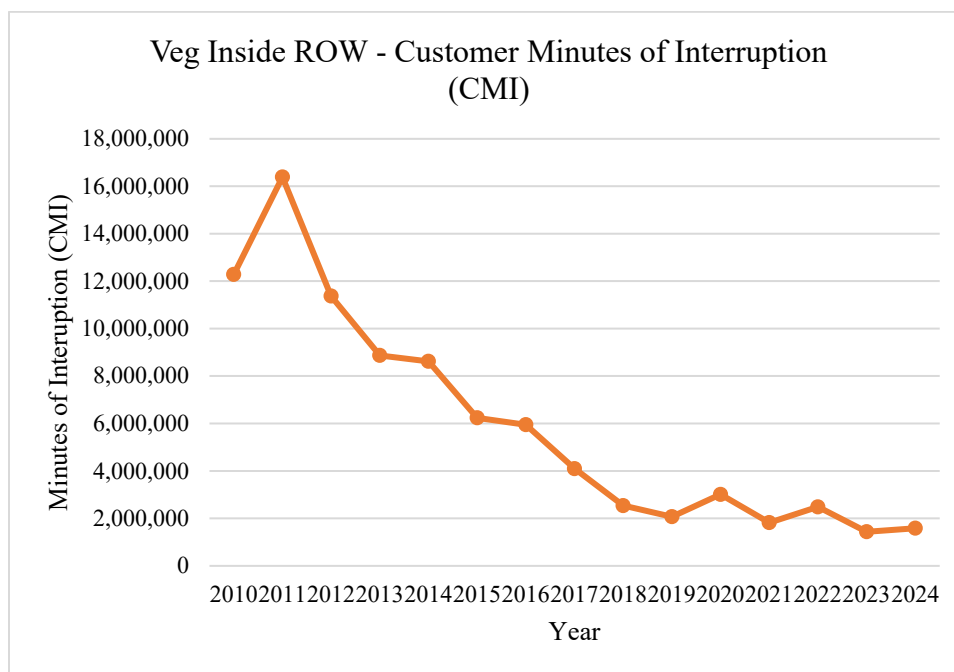
**Q. PLEASE PROVIDE A SUMMARY OF THE TIR PROGRAM.**

A. The TIR Program is a cycle-based maintenance program that completes vegetation clearing and inspection of all distribution circuit rights-of-way once every five years. These inspections and clearing activities target both trees inside the Company rights-of-way as well as vines that become entangled in distribution facilities in the right-of-way. The Company began the current five-year cycle-based Vegetation Management Program (TIR Program) on January 1, 2023. Activities associated with the program include inspections, customer communications, brush removal, tree trimming and 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.

Figure MR-6 illustrates a significant reduction in CMI due to addressing trees and vines inside the rights-of-way, decreasing from 16,388,594 minutes in 2011 to 1,585,590

minutes by December 31, 2024. This represents an approximate 90% improvement in TIR-related CMI between 2011 and 2024.

**Figure MR-6 – TIR CMI Reduction Trend**



**Q. DOES THE COMPANY EXPECT THE TIR PROGRAM TO CONTINUE CONTRIBUTING TO ENHANCED RELIABILITY FOR CUSTOMERS?**

A. Yes. Interruptions and CMI statistics attributable to the TIR program are expected to continue enhanced reliability performance due to the completion of the end-to-end maintenance clearing for the entire primary distribution system on the five-year cycle, delivering the ongoing control of the distribution system rights-of-way.

The trend since 2011, as shown in Figure MR-6 underlines the success the Company and its customers are experiencing from the investment in distribution vegetation management. Due to the significant reliability improvements made by lowering CMI related to TIR outages, it is important and prudent to continue investing the appropriate funding levels to ensure the continued success of the program. Any deviation from the

1 current program can possibly cause an uptick in customer CMI and require even more  
2 investment to bring the issues back under control.

3 **Q. WHAT DOES THE COMPANY PROPOSE WITH RESPECT TO THE ONE-WAY**  
4 **BALANCING MECHANISM ASSOCIATED WITH THE COMPANY'S**  
5 **VEGETATION MANAGEMENT – TIR PROGRAM?**

6 A. The Company intends to continue the one-way balancing account until further order of the  
7 Public Service Commission of Kentucky (“Commission”). The Company is proposing to  
8 change the budget for the one-way balancing account going forward from \$22,421,864 to  
9 \$22,825,396.

10 **Q. PLEASE DESCRIBE THE NEED TO ADJUST THE ANNUAL BUDGET FOR**  
11 **THE ONE-WAY BALANCING ACCOUNT.**

12 A. The increase in the current annual level of vegetation management O&M from \$22.4  
13 million to \$22.8 million is reasonable and necessary due to the increased costs of labor,  
14 equipment, and vine mitigation. As explained above, since 2011, Kentucky Power’s  
15 investments have resulted in a 90% reduction in TIR related CMI. The current clearing  
16 cycle has proven to be effective, and Kentucky Power must continue to make incremental  
17 investments in vegetation management to maintain its current TIR outage performance.

18 **Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO ITS TEST-YEAR**  
19 **EXPENSE TO REFLECT THE PROPOSED ONE-WAY BALANCING ACCOUNT**  
20 **BUDGET?**

21 A. Yes. I am supporting an adjustment to decrease the test-year level of O&M for the TIR  
22 Program by (\$6,159,962). The adjustment results in a decrease because the Company test  
23 year reflects approximately \$29 million of vegetation management expense. Notably, the

level of TIR Program expense in the Company's test year was higher than that of calendar year simply due to when work was performed. This proposed adjustment is reflected below in Figure MR-7 and as Adjustment W50 in Section V of the Company's Application.

**Figure MR-7 – Kentucky Power Adjusted Test-Year Distribution TIR O&M Expenses**

Description	FERC Account	Proposed Adjustment Amount
Test-Year Vegetation Management Expense	593	\$28,985,358
Adjusted Annual Vegetation Management O&M	593	\$22,825,396
Total Adjustment to Test Year	593	(\$6,159,962)

**TOR Program**

**Q. PLEASE PROVIDE A SUMMARY OF KENTUCKY POWER'S TOR PROGRAM.**

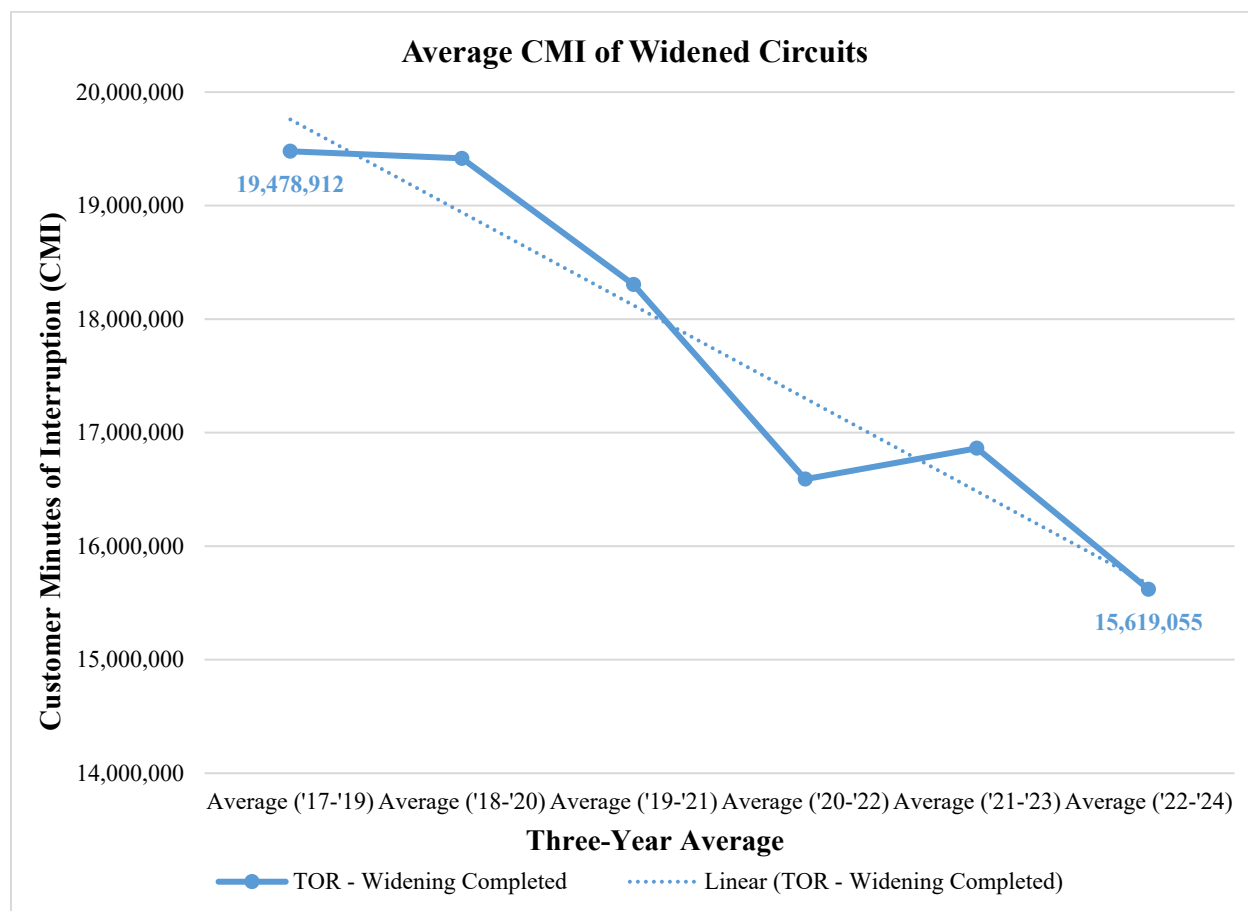
A. Beginning with the Company's 2018 Vegetation Management Plan, Kentucky Power established a pilot program to address the Company's existing outside of the right-of-way trees, including the removal of danger trees on a limited number of certain circuits. Following the successful pilot program, the Company expanded the TOR Program to additional circuits across all service districts based on circuit performance. As demonstrated above, vegetation, particularly TOR, remains the principal cause of outages in Kentucky Power's service territory.

**Q. DOES THE COMPANY HAVE EVIDENCE THAT THE PILOT TOR PROGRAM DELIVERED IMPROVED RELIABILITY FOR CUSTOMERS?**

A. Yes. Figure MR-8 illustrates a positive correlation between the TOR ROW widening efforts and reliability improvements. This graph illustrates the CMI performance for circuits that underwent ROW widening. As shown in Figure MR-8, circuits with ROW

widening experienced a decrease in CMI. Specifically, there was approximately a 20% decrease in CMI for widened circuits compared to the three-year average from 2017–2019.

**Figure MR-8 – Average CMI of Widened Circuits**



These results indicate that ROW widening is an effective measure to mitigate vegetation impacts on distribution facilities. With storms becoming more severe, addressing vegetation is critical, as it accounts for over half of the annual CMI. Therefore, it is prudent to invest in solutions that specifically target this outage cause.

**Q. IS THE COMPANY PROPOSING ANY ADJUSTMENTS TO THE TOR PROGRAM AS PART OF THIS FILING?**

**A.** Yes. I am supporting an adjustment to Distribution capital plant in service of \$18 million for known and measurable increases to expand the Company's TOR Program. This



proposed adjustment is reflected below in Figure MR-9 and as Adjustment W50 Capitalization in Section V of the Company's Application.

**Figure MR-9 – Kentucky Power Distribution Capital Adjustments**

Adjusted Kentucky Retail Jurisdiction Distribution Plant	FERC Account	Description	Proposed Adjustment Amount
Distribution Plant	365	TOR Program	\$18,000,000
<b>Total</b>		<b>Distribution Plant Adjustment</b>	<b>\$18,000,000</b>

**Q. WHY IS EXPANSION OF AND INCREASED INVESTMENT IN THE TOR PROGRAM NECESSARY, AND WHAT BENEFITS DOES IT BRING TO CUSTOMERS AND THE COMPANY?**

A. As demonstrated in Figure MR-2 above in my Direct Testimony, outages attributable to trees outside the right-of-way were the number one cause of CMI in 2024, causing about 55% of outages. Conversely, outages attributable to trees inside the right-of-way made up only about 2% of all outages in 2024. The Company's low percentage of outages caused by trees inside the right-of-way is directly attributed to the years-long investments made in the TIR Program as demonstrated in Figure MR-6.

Given the success of the increased investment and robust clearing schedule associated with the TIR Program, the Company recognizes an opportunity to duplicate that success with an expanded TOR Program, which requires a concurrent increase in investment in the TOR Program. For example, in 2024 Kentucky Power invested approximately \$4.6 million in the TOR Program, and over \$22.2 million in the TIR Program. The goal for the proposed \$18 million capital plant-in-service adjustment to expand the TOR Program is to decrease outages attributable to trees outside the right-of-way and continue to improve reliability for all of the Company's customers.

1           Additionally, reducing outages caused by trees outside the right-of-way can lower  
2           capital and O&M costs across several areas. For example, with fewer trees falling on  
3           distribution assets, less construction will be required for outage restoration. Tree impacts  
4           on poles can lead to severe damage, making restoration projects both expensive and  
5           time-consuming. Kentucky Power's performance will be demonstrated by improved  
6           CAIDI, SAIDI, SAIFI, and CMI metrics.

7   **Q.   HOW WILL KENTUCKY POWER IDENTIFY PROJECTS/CIRCUITS FOR THE**  
8   **TOR PROGRAM?**

9   A.   Kentucky Power will review distribution circuit CMI metrics to identify which have the  
10       highest TOR impacts. Kentucky Power will begin by analyzing the affected circuits and  
11       then conduct a more in-depth examination of zonal impacts. This approach allows for a  
12       detailed assessment of line sections. Once the analysis is complete, the Company will  
13       implement targeted vegetation clearing to reduce outages caused by vegetation impacts.  
14       For a list of circuits where widening will occur, see Exhibit MR-4 TOR Reliability  
15       Widening Workplan.

16   **VII.       THE COMPANY'S DISTRIBUTION CAPITAL INVESTMENTS AND**  
17       **TEST-YEAR O&M EXPENSES ARE REASONABLE**

18                   **Distribution Capital Investments**

16   **Q.   PLEASE DESCRIBE THE KINDS OF DISTRIBUTION CAPITAL ADDITIONS**  
17       **THAT KENTUCKY POWER HAS MADE SINCE ITS LAST BASE RATE CASE.**

18   A.   The Company has invested in the following general capital project categories necessary  
19       to provide safe and reliable electric service to new and existing customers since its last base  
20       rate case:

- 21           • Asset Improvement: Replacement of outdated, failing equipment, and other  
22           necessary infrastructure upgrades needed to maintain safe and reliable electric

service for Kentucky Power customers. More specifically, the Asset Improvement project category primarily includes poles, overhead circuit and underground-fed structure inspections and repairs along with sub-station breaker replacements.

- Customer Service: Work required to connect new customers and customers who upgrade their facilities that are connected to the distribution system as well as the costs of the necessary transformers and meters.
- Vegetation Management Program: 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 rights-of-way, or to establish a new clearance zone for new construction.
- Planning Capacity: Projects developed as part of Kentucky Power's long-range planning for meeting electrical load needs on Kentucky Power's distribution system. The need for capacity expansion is due to either new customers or new load from 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: Investments to restore 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 ITS LAST BASE RATE CASE?**

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

Intangible capital projects represent routine software updates, as well as the support of cloud-based programs and Software as a Service ("SaaS") applications that enable the operation and enhance the efficiency of Kentucky Power's Distribution organization.

1 These SaaS solutions provide scalable resources and continuous updates, ensuring that the  
2 organization remains agile and responsive to evolving operational needs.

3 General plant capital projects include:

- 4 • Telecommunication upgrades necessary to improve internal Kentucky Power  
5 communications. These upgrades allow for more efficient transfer of information and  
6 data within the Company. For field employees, these upgrades facilitated  
7 improvements to radio systems that provides a more reliable connection to teams such  
8 as dispatch. For one such project, Kentucky Power migrated from an old, leased site  
9 onto a brand new owned site. This new site hosts equipment that provides an increased  
10 radio communication footprint across the area by upgrading outdated technology with  
11 enhanced radio systems.
- 12 • Improvements and investments in Kentucky Power Distribution buildings. For  
13 example, Kentucky Power replaced the roof at the Pikeville operations center in 2024.  
14 Improvements such as these keep facilities safe for the Company's workforce, and  
15 ensure the Company is able to facilitate the work needed to safely and reliably service  
16 the distribution system.

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

19 A. The Company has invested approximately \$184.6 million of capital in distribution since  
20 the end of the test year in its last base rate case, or from April 1, 2023, through May 31,  
21 2025.

22 This \$184.6 million consists of \$164.9 million for Asset Improvement, Customer  
23 Service, Vegetation Management, Planning Capacity, Reliability, and System Restoration

projects. The remainder includes \$7.1 million of Distribution-Intangible Plant, and \$12.6 million of Distribution-General Plant.

A breakdown of Kentucky Power's distribution capital additions by general project category for April 1, 2023, through May 31, 2025, is provided in Figure MR-10.

**Figure MR-10 – Kentucky Power Distribution Capital Additions (\$)**

	4/1/2023– 12/31/2023	1/1/2024– 12/31/2024	1/1/2025– 5/31/2025	6/1/2024– 5/31/2025	4/1/2023– 5/31/2025
<b>CATEGORY</b>	<b>2023 (partial)</b>	<b>2024</b>	<b>2025 (partial)</b>	<b>TEST YEAR</b>	<b>TOTAL</b>
Asset Improvement	\$12,017,663	\$34,726,090	\$9,508,487	\$39,239,383	\$56,252,240
Customer Service	\$11,206,613	\$13,953,937	\$9,401,946	\$17,288,349	\$34,562,496
Vegetation Mgmt. Program	\$1,370,241	\$12,772,424	\$674,502	\$5,157,351	\$14,817,166
Planning Capacity	\$10,249,092	\$1,522,284	\$739,391	\$1,448,775	\$12,510,768
Reliability	\$7,673,250	\$12,577,482	\$2,075,328	\$11,787,221	\$22,326,060
System Restoration	\$6,177,963	\$9,108,664	\$9,159,367	\$12,813,095	\$24,445,994
<b>Sub-Total</b>	<b>\$48,694,822</b>	<b>\$84,660,881</b>	<b>\$31,559,021</b>	<b>\$87,734,174</b>	<b>\$164,914,724</b>
Intangible Plant	\$3,450,440	\$3,566,563	\$87,479	\$2,478,867	\$7,104,482
General Plant	\$5,886,098	\$4,984,861	\$1,703,581	\$5,058,601	\$12,574,540
<b>Sub-Total</b>	<b>\$9,336,538</b>	<b>\$8,551,424</b>	<b>\$1,791,060</b>	<b>\$7,537,468</b>	<b>\$19,679,022</b>
<b>Total</b>	<b>\$58,031,360</b>	<b>\$93,212,305</b>	<b>\$33,350,081</b>	<b>\$95,271,642</b>	<b>\$184,593,746</b>

**Q. ARE THE TEST-YEAR AMOUNTS OF KENTUCKY POWER'S DISTRIBUTION CAPITAL EXPENSE INCLUDING YOUR PRO FORMA ADJUSTMENT TO CAPITAL PLANT IN SERVICE REASONABLE?**

**A.** Yes. The test-year amounts of capital additions are in-line with historical spending over time and these amounts represent the investments required to continue to support safe and reliable service to customers.

**Distribution O&M Expenses**

1    **Q.    WHAT WERE THE ANNUAL AND TEST-YEAR LEVEL OF KENTUCKY**  
2        **POWER’S DISTRIBUTION O&M EXPENSES SINCE THE COMPANY’S LAST**  
3        **BASE RATE CASE?**

4    **A.**    Figure MR-11 provides Kentucky Power’s per book (unadjusted) distribution O&M  
5        expenses by Federal Energy Regulatory Commission (“FERC”) account for the past four  
6        calendar years and the test year.

**Figure MR-11 – Kentucky Power Distribution O&M Expenses (\$)¹**

	FERC ACCT	2021	2022	2023	2024	Test Year
Distribution Operation	5800	\$829,970	\$805,659	\$873,874	\$1,192,931	\$1,451,741
	5810	\$3,410	\$1,964	\$1,968	\$1,048	\$2,864
	5820	\$259,294	\$388,479	\$325,489	\$387,429	\$370,026
	5830	\$397,079	\$351,141	\$469,216	\$281,948	\$723,607
	5840	\$152,750	\$238,861	\$260,153	\$326,743	\$362,840
	5850	\$78,060	\$46,816	\$59,168	\$40,246	\$32,898
	5860	\$1,151,401	\$1,229,732	\$1,211,647	\$1,353,435	\$1,216,051
	5870	\$193,715	\$200,910	\$222,454	\$191,956	\$159,098
	5880	\$2,424,122	\$3,192,387	\$3,337,241	\$6,285,823	\$5,777,410
	5890	\$242,074	\$933,528	\$796,344	\$1,048,358	\$1,105,284
Subtotal		\$5,731,877	\$7,389,475	\$7,557,555	\$11,109,917	\$11,201,820
Distribution Maintenance	5900	\$26,434	\$5,110	\$18,724	\$15,594	\$57,091
	5910	\$8,122	\$20,773	\$3,289	\$10,318	\$14,906
	5920	\$683,774	\$337,440	\$784,295	\$888,071	\$952,822
	5930	\$33,683,296	\$33,194,092	\$32,117,233	\$31,281,486	\$29,678,038
	5940	\$19,443	\$48,395	\$24,053	\$24,176	\$33,645
	5950	\$52,827	\$23,586	\$33,838	\$16,734	\$7,710
	5960	(\$8,742)	\$20,854	\$24,697	\$9,850	\$7,687
	5970	\$50,515	\$33,477	\$34,288	\$37,643	\$41,553
	5980	\$20,541	\$25,517	\$20,915	\$27,046	\$27,546
Subtotal		\$34,536,208	\$33,709,243	\$33,061,331	\$32,310,918	\$30,820,998
<b>Total</b>		<b>\$40,268,085</b>	<b>\$41,098,719</b>	<b>\$40,618,886</b>	<b>\$43,420,834</b>	<b>\$42,022,818</b>
* Note: negative number is generally the result of reimbursements for make ready work related to pole attachments.						

1 **Q. PLEASE DISCUSS THE TEST-YEAR O&M EXPENDITURES.**

2 A. The Company's test-year O&M is consistent with historical spending. The four-year  
3 average from the above time period is \$41.35 million. During the test year, the Company  
4 spent approximately \$42.02 million, about \$671,187 more than the annual average  
5 expenses incurred over the past four years. This difference is in line with the Company's

¹ Numbers in this table have been rounded to the nearest whole value.

1 expectations and is consistent with expected year-over-year variability (*i.e.*, events such as  
2 storms), while also illustrating the increases in prices for equipment and labor.

3 **Q. ARE THE TEST-YEAR AMOUNTS OF KENTUCKY POWER’S DISTRIBUTION**  
4 **O&M EXPENSE INCLUDING YOUR ADJUSTMENT REASONABLE?**

5 A. Yes. The test-year amounts of O&M, including the known and measurable adjustments  
6 discussed above, are in line with the Company’s historical O&M expenditures since its last  
7 base rate case. Additionally, the adjustments listed in Figure MR-7 represent the amount  
8 necessary for the Company to continue to provide safe and reliable service to its customers,  
9 while adding positively to the customer experience as described in my Direct Testimony.

**VIII. ADVANCED METERING INFRASTRUCTURE (“AMI”) PLANS**

10 **Q. WHAT IS THE STATUS OF THE COMPANY’S IMPLEMENTATION OF AMI**  
11 **METERS SINCE THE COMMISSION ISSUED ITS ORDER GRANTING A CPCN**  
12 **IN CASE NO. 2024-00344 ON JULY 22, 2025 (“AMI ORDER”)?**

13 A. The Company is currently in the final stages of preparation prior to beginning execution of  
14 the AMI project. Kentucky Power is collaborating with the vendor to finalize  
15 communication strategies for devices aimed at serving the Company’s most rural  
16 customers. Then, the Company will proceed to finalize the contract with the vendor. Once  
17 the contract is executed, Kentucky Power will initiate system implementation by ordering  
18 the necessary equipment to establish the AMI communication backhaul.



1   **Q.    THE AMI ORDER REQUIRED KENTUCKY POWER TO BEGIN TO DEVELOP**  
2       **DETAILED PLANS ON AMI OBSOLESCENCE AND REPLACEMENT**  
3       **STRATEGIES. CAN YOU PLEASE PROVIDE THE COMPANY’S INITIAL**  
4       **PLANS IN AS MUCH DETAIL AS CURRENTLY POSSIBLE, GIVEN THAT THE**  
5       **AMI ORDER WAS ISSUED ABOUT A MONTH AGO?**

6   **A.**   Kentucky Power’s AMI solution is based on state-of-the-art, next-generation AMI  
7       technology, designed for a 20-year lifecycle. Kentucky Power proactively developed  
8       strategies to ensure greater integration on the distribution system, adaptability to future  
9       technological advancements and the support of firmware updates, enabling ongoing device  
10      enhancements over time. Kentucky Power is currently working with a vendor to outline  
11      the scope, projected schedule, highlighting key milestones and timelines for each project  
12      phase, detailing the expected deliverables and specific requirements and deployment plan  
13      aimed at ensuring successful implementation.

14           To further combat obsolescence, the vendor will notify the Company of a meter’s  
15      end-of-life date two years in advance, facilitating the transition to new meter technologies  
16      and ensuring availability of parts. Kentucky Power will perform comprehensive research  
17      to assess emerging advancements, aiming to identify additional potential benefits for  
18      customers.

1   **Q.   THE AMI ORDER ALSO REQUIRED KENTUCKY POWER TO BEGIN TO**  
2       **DEVELOP DETAILED PLANS ON IDENTIFYING OUTAGES AND HOW THE**  
3       **AMI SYSTEMS WILL FACILITATE NOTIFICATION AND COMMUNICATION**  
4       **OF INFORMATION WITH CUSTOMERS REGARDING OUTAGES. PLEASE**  
5       **PROVIDE THOSE PLANS IN AS MUCH DETAIL AS CURRENTLY POSSIBLE,**  
6       **GIVEN THAT THE AMI ORDER WAS ISSUED ABOUT A MONTH AGO.**

7   **A.**   In response to the AMI order, Kentucky Power has developed several strategies to enhance  
8       outage response immediately following the installation of AMI meters. While the meters  
9       play a crucial role in aggregating data, it is important to note that they do not independently  
10      dictate or communicate estimated restoration times. Instead, the Company relies on its  
11      current Outage Management System (“OMS”) for customer communications regarding  
12      outages. Restoration time estimates are typically based on historical trend data and are  
13      further evaluated by service personnel. Once an assessment is made, the estimated  
14      restoration time is shared with the system operator and communicated through the  
15      Company’s notification channels. Customers can currently receive alerts via e-mail, text,  
16      phone call, or mobile application push notification. Furthermore, this information is  
17      aggregated and presented on the Company’s online outage map. If a customer wants more  
18      specific detail regarding their outage, they may find more information such as crew status  
19      and area affected utilizing that resource.

20           The AMI meters will significantly improve the speed at which system operators  
21      can locate outages. When an AMI meter detects a loss of source-side voltage, it  
22      automatically reports this to the dispatch center, triggering an outage report. This enables  
23      system operators to investigate the situation promptly, and in some cases, a servicer may

1 be dispatched and enroute to the outage location even before a customer has reported the  
2 issue. Additionally, the dispatch center may identify isolation devices, allowing operators  
3 to direct service personnel to patrol specific areas, which ultimately saves time during  
4 outage restoration.

5 The widespread deployment of AMI meters will also enhance the Company's  
6 mapping accuracy. For example, if an AMI meter indicates that one phase is out, but a  
7 service technician discovers that the issue lies with a different phase, the Company can  
8 update its maps accordingly. This results in greater mapping accuracy and reduces the  
9 likelihood of erroneous outage alerts being communicated to customers.

10 **Q. DOES THE COMPANY ANTICIPATE THAT THESE PLANS MAY EVOLVE AS**  
11 **THE COMPANY BEGINS TO IMPLEMENT AMI?**

12 A. Kentucky Power anticipates that AMI installation plans may evolve as the initiative  
13 progresses, which is typical for large-scale projects. The team will continuously monitor  
14 and oversee the project's advancement by leveraging data and insights obtained from initial  
15 installations. This strategy will enable timely adjustments to ensure that project timelines  
16 are met.

17 **Q. WILL THE COMPANY PROVIDE THE COMMISSION WITH UPDATES TO**  
18 **THESE PLANS IF ORDERED TO DO SO?**

19 A. Yes. The Company understands its obligation to provide these plans with its next base rate  
20 case as required by the AMI Order to be fulfilled. However, the Company can provide any  
21 additional updates as the Commission orders them.

**IX. UPDATE ON SMARTGRID INVESTMENTS**

1   **Q.   PLEASE DESCRIBE “SMART GRID” INVESTMENTS.**

2   A.   In its April 13, 2016, Order in Case No. 2012-00428, the Commission directed each utility  
3       in the Commonwealth subject to its jurisdiction to identify its Smart Grid investments in  
4       each base rate case. Smart grid technology enhances the efficiency, reliability, and safety  
5       of the distribution system by utilizing advanced information tools. The information  
6       provided in this section fulfills that Commission directive.

7   **Q.   WHAT CONTINUED SMART GRID INVESTMENTS HAS THE COMPANY**  
8       **MADE SINCE ITS LAST BASE RATE CASE?**

9   A.   Since its last base rate case, Kentucky Power has made \$1,038,020 in Smart Grid  
10       investments in its distribution system. Much of the investments have been made in support  
11       of Distribution Automation Circuit Reconfiguration (“DACR”). These investments allow  
12       for a series of automated actions that can reduce the impact and duration of an outage. If a  
13       fault occurs on a distribution line that has DACR, the DACR system can recognize the fault  
14       location, isolate the damaged portion of line, and restore unaffected customers through  
15       other portions of DACR construction, all before a truck is dispatched to the scene.

16           To facilitate these processes, Kentucky Power utilizes a Distribution Management  
17       System that includes Supervisory Control and Data Acquisition (“SCADA”) to provide  
18       system analysis and remote control of the distribution system. The Data Management  
19       System gathers information from electronic devices in the field, including the DACR  
20       equipment, and integrates it with the mapping system to provide the real-time status of  
21       these automated circuits. It also allows remote operation of devices on those circuits by  
22       dispatchers if immediate intervention, maintenance, or load control is needed.

1           These Smart Grid investments provide customer benefits and an enhanced customer  
2           experience. For example, upgrades to some of the Smart Grid investments have improved  
3           DACR logic, which allows for more reliable and diversified automated reactions, as well  
4           as greater monitoring capabilities of the DACR scheme.

5           The Company also has made Smart Grid investments that include the construction  
6           of new station and line equipment in order to split up overhead line miles on already  
7           existing distribution circuits. Splitting up the overhead line miles facilitates redundancy for  
8           customers in the area and can improve reliability by providing an alternate source of power  
9           in the event of an outage. Furthermore, the greater coordination offered by splitting these  
10          circuits lays a better foundation for future DACR investments.

11          Ultimately, these types of Smart Grid investments reduce the frequency and  
12          duration of customer outages. For this reason, the Company constantly looks for  
13          opportunities to incorporate Smart Grid investments into the construction of new  
14          distribution circuits.

## **X. CONCLUSION**

15   **Q.   DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

16   **A.   Yes, it does.**

## VERIFICATION

The undersigned, Michele Ross, being duly sworn, deposes and says she is a Vice President of Distribution Region Operations 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.

  
Michele Ross

Commonwealth of Kentucky )  
 )  
County of Boyd )

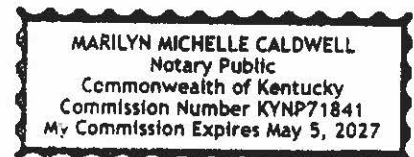
Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County  
and State, by Michele Ross, on August 26, 2025.

  
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

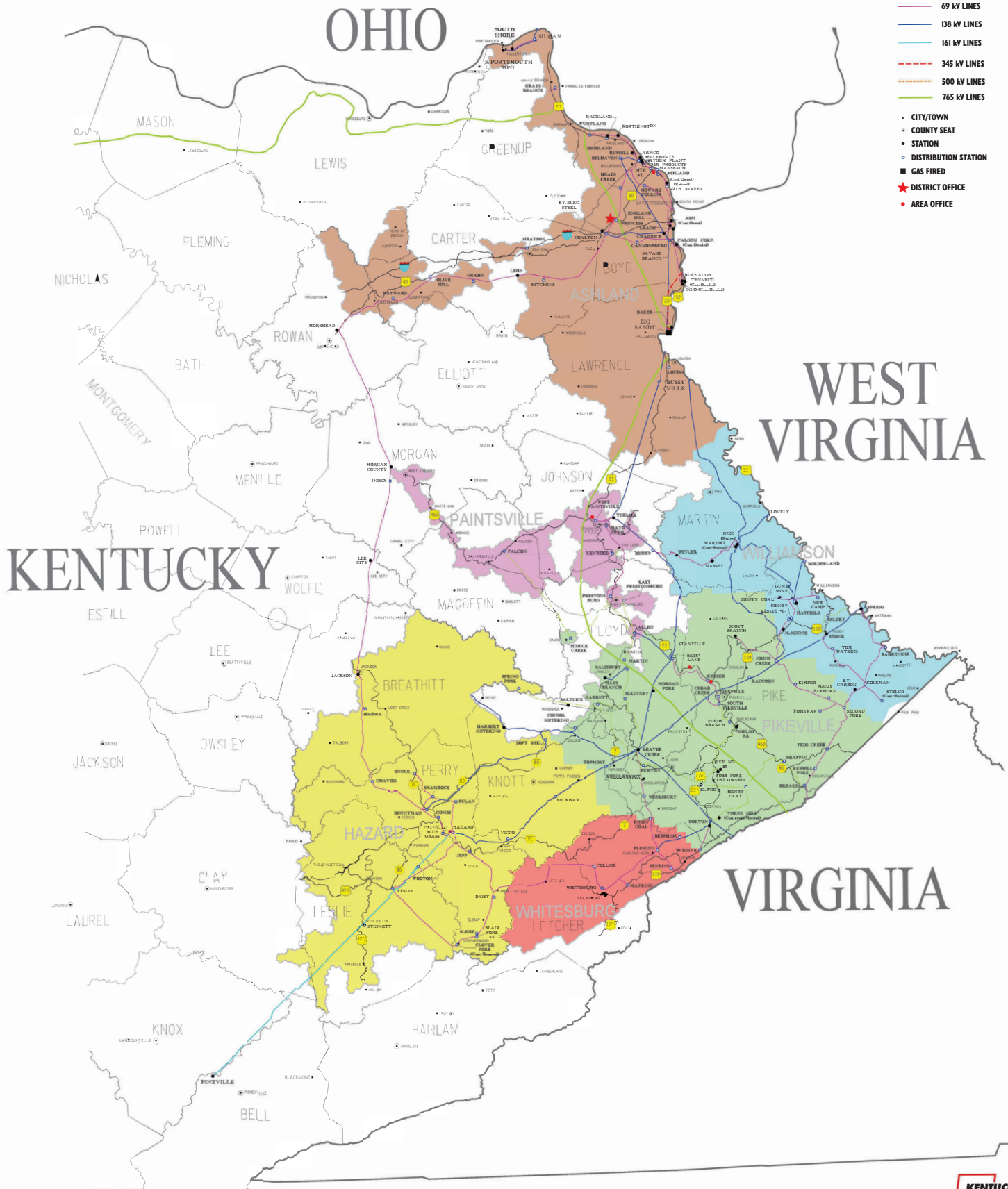


# Kentucky Power Service Area

Exhibit MR-1  
Page 1 of 1

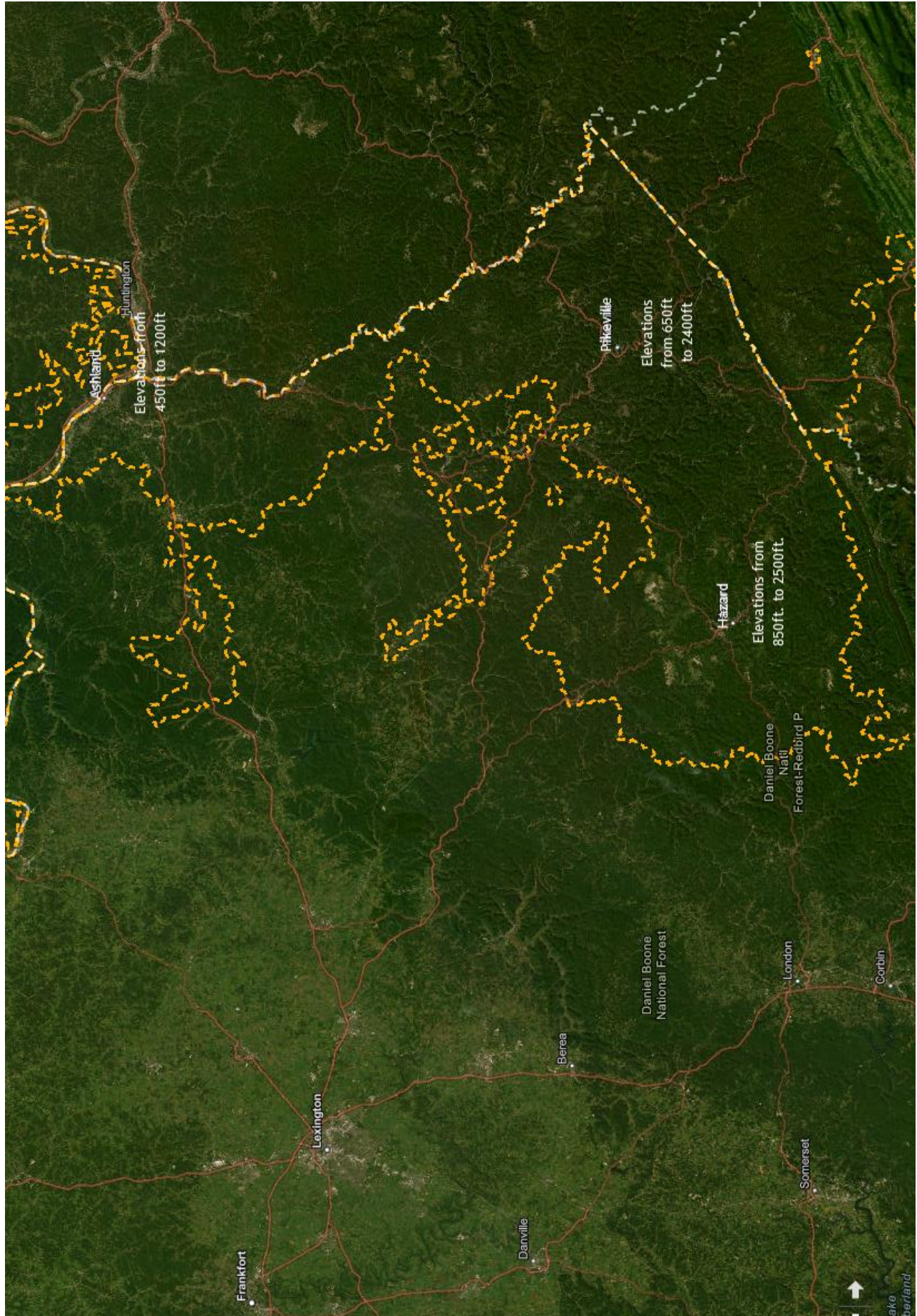
## LEGEND

- 34.5 KV LINES
- 46 KV LINES
- 69 KV LINES
- 138 KV LINES
- 161 KV LINES
- 345 KV LINES
- 500 KV LINES
- 765 KV LINES
- CITY/TOWN
- COUNTY SEAT
- STATION
- DISTRIBUTION STATION
- GAS FIRED
- DISTRICT OFFICE
- AREA OFFICE





# Kentucky Power Vegetation Density

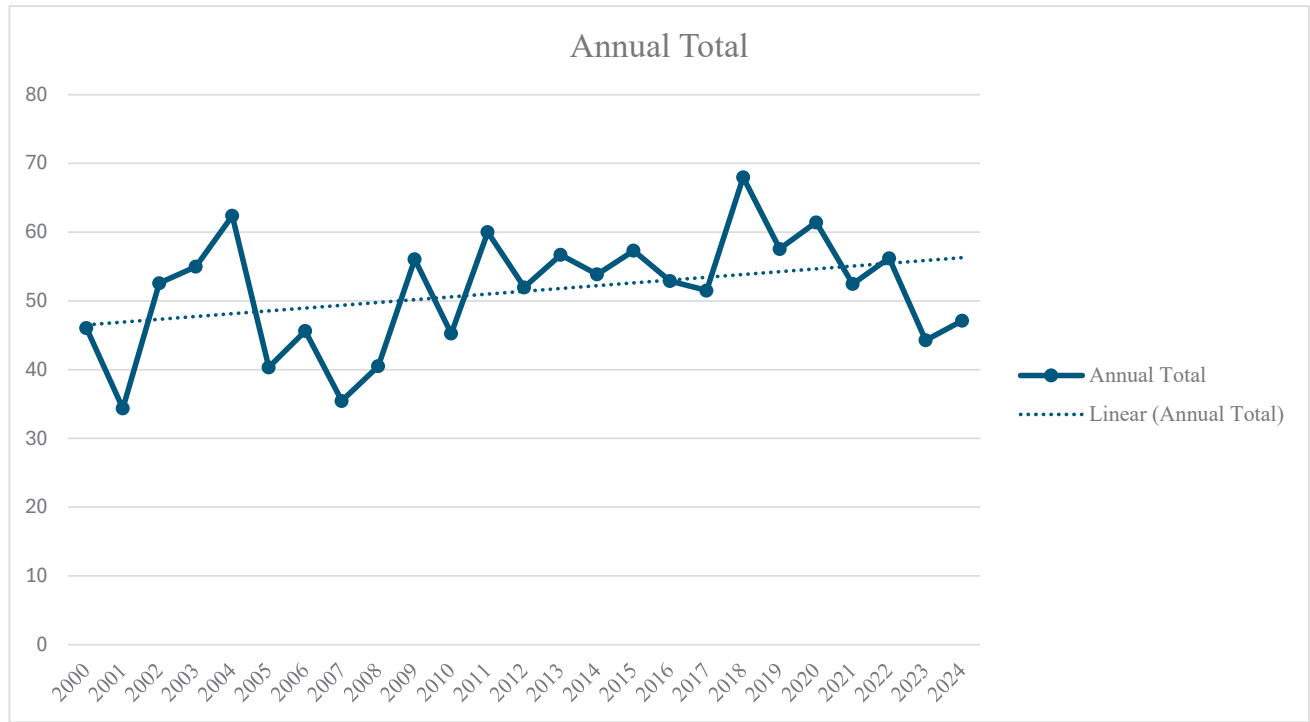




Recorded Data from National Weather Service for Jackson, KY															
30 Yr Normal Precip (1981 - 2010)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Norm		
Jackson, KY Area	3.61	3.75	4.12	3.83	5.2	4.7	4.65	3.69	3.46	3.19	3.96	4.18	48.34		
Monthly Total Inches Precipitation for Jackson, KY Area	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total	
	2000	2.63	3.53	1.94	4.97	4.33	6.8	5.69	4.38	4.92	1.07	1.47	4.35	46.08	
	2001	2.5	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	5.5	1.72	3.48	6.39	3.61	4.28	52.59	
	2003	2.1	7.88	1.47	5.14	5.98	7.54	3.95	5.12	4.33	2.2	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	62.4	
	2005	5.12	3.03	3.52	7.47	2.5	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	1.2	2.71	3.22	1.82	2.15	4.05	2.64	2.49	3.8	3.37	5.18	35.46	
	2008	2.46	3.41	4.14	4	3.24	3.94	6.13	1.16	0.67	1.46	3.03	6.86	40.5	
	2009	5.8	1.73	3.52	3.64	9.22	7.03	6.4	3.55	4.88	3.54	0.8	5.96	56.07	
	2010	4.27	3.11	2.43	2.61	7.92	5.6	3.34	3.51	2.05	1.68	5.77	2.97	45.26	
	2011	2.72	3.97	4.74	10.2	6.69	5.49	6.02	3.07	3.2	4.25	5.48	4.18	60.01	
	2012	4.86	3.9	4.07	2.67	4.2	1.91	7.39	4.75	6.77	4.24	0.84	6.39	51.99	
	2013	5.73	1.91	4.63	3.7	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	2.3	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	2.4	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	1.3	3.28	51.52	
	2018	1.92	8	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	2.4	2.8	4.9	8.01	6.97	1.25	T	6.01	5.8	6.3	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	3.6	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	3.15	3.78	3.64	5.87	6.96	1.83	1.43	1.72	2.4	44.27	
	2024	4.77	5.66	2.91	3.39	4.89	5.53	3.67	3.03	4.49	0.21	3.67	4.9	47.12	
	2025	4.67	7.89	2.31	9.2	8.28	5.99								
	20 Yr Mean (through May 2025)	4.10	4.76	4.17	4.63	5.06	4.90	6.12	4.78	3.17	3.24	3.03	4.64	51.73	
	3 Yr Mean ('22 - '24)	4.57	6.23	3.10	5.25	5.65	5.05	8.13	4.55	2.54	0.82	2.73	3.66	49.20	
5 Yr Mean ('20 - '24)	4.99	6.48	3.39	4.55	5.14	4.49	7.47	5.73	2.76	1.7	2.56	3.72	52.30		

NOWData Search via <https://www.weather.gov/wrh/climate?wfo=jkl>

1 Location: Jackson Area | 2 Product: Monthly summarized data | 3. Options: 2000-2025, Precipitation, Sum | 4 Click GO



Area	Station	Circuit	Circuit Number	Average Yearly CMI for Years 2022-2024	2024 CMI	2022-2024 Average CMI Ranking	2024 CMI Ranking	Total Primary Circuit Miles	Targeted Widening in Proforma Period	Year of Widening Activity	Widening Considered Complete
Pikeville	Dewey	Inez	3411401	1,531,566	1,456,650	1	1	171.06	Y	2025	N
Hazard	Beckham	Hindman	3308401	872,040	1,123,263	2	2	101.91	Y	2025	N
Hazard	Haddix	Quicksand	3310501	821,907	301,432	3	43	128.12	N	2025	N
Hazard	Leslie	Hyden	3303901	753,325	632,903	4	12	89.59	Y	2025	N
Hazard	Bonnyman	Big Creek	3308503	684,192	324,389	5	38	86.37	N	2025	N
Hazard	Leslie	Wooton	3303902	611,647	516,117	6	16	129.66	N	2025	N
Hazard	Leslie	Hals Fork	3303903	597,098	352,195	7	31	76.7	N	2026	N
Hazard	Stinnett	Redbird	3311101	583,162	934,637	8	4	117.37	Y	2026	N
Ashland	Busseyville	Walbridge	3007906	577,089	285,543	9	47	96.09	N	2025	N
Hazard	Haddix	Canoe	3310502	548,806	282,278	11	48	123.08	N	2026	N
Hazard	Fleming (Jackhom)	McRoberts (Cromona/McRoberts)	3401302	527,380	712,502	12	10	9.2	N	2026	N
Hazard	Mayking	Millstone	3314402	522,997	297,316	13	45	53.08	N	2026	N
Hazard	Engle	Grapvine	3312202	505,455	324,536	14	37	100.81	N	2026	N
Pikeville	Barrenshe	Vulcan	3200202	480,483	331,934	15	35	41.05	N	2026	N
Pikeville	Raccoon	Zebulon	3421301	453,027	823,819	16	6	111.25	N	2026	N
Hazard	Collier	Smoot Creek	3308603	452,970	358,097	17	30	81.17	N	2027	N
Pikeville	Falcon	Burning Fork	3401103	450,123	737,559	18	8	73.48	N	2027	N
Hazard	Jeff	Viper	3309003	387,225	340,747	19	33	66.62	N	2027	N
Pikeville	Lovely	Wolf Creek	3202202	378,789	737,602	20	7	60.37	Y	2026	N
Ashland	Belhaven	Argillite	3116703	376,596	978,901	21	3	27.57	Y	2025	N
Hazard	Haddix	Troublesome Creek	3310503	370,530	497,893	22	18	91.4	Y	2025	N
Hazard	Whitesburg	Crafts Colley	3309104	352,493	458,064	23	19	28.01	N	2027	N
Pikeville	Stanville	Mud Creek	3120101	349,266	373,852	25	27	85.72	N	2027	N
Ashland	Hayward	Haldeman	3000801	348,672	298,103	26	44	121.07	N	2027	N
Hazard	Beckham	Pippa Passes	3308404	331,637	570,599	28	15	63.01	N	2027	N
Pikeville	Lovely	Lovely	3202201	329,992	237,471	29	58	42.24	N	2027	N
Ashland	Bellefonte	Bellefonte	3000303	321,299	506,382	30	17	58.24	Y	2025	N
Hazard	Daisy	Leatherwood	3301701	313,321	424,504	32	21	87.39	N	2028	N
Ashland	Big Sandy	Fallsburg	3000201	311,912	405,970	33	24	105.47	Y	2026	N
Ashland	Busseyville	Torchlight	3007906	299,185	359,698	35	29	97.13	Y	2025	N
Hazard	Vicco	Jeff	3309302	298,461	203,998	36	68	89.12	N	2028	N
Ashland	Highland	Flatwoods	3000902	296,521	857,033	37	5	20.07	Y	2026	N
Hazard	Bulan	Lotts Creek	3307303	287,348	680,522	39	11	33.53	N	2028	N
Pikeville	Johns Creek	Meta	3411801	281,369	363,262	40	28	60.43	N	2028	N
Hazard	Whitesburg	Cowan	3309103	278,935	399,043	41	25	43.74	N	2028	N
Pikeville	Kenwood	Auxier	3409302	271,547	432,100	42	20	41.02	N	2028	N
Hazard	Bulan	Ajax - Dwarf	3307302	266,986	208,760	44	64	41.52	N	2028	N
Ashland	Wurtland	Rt 503	3110903	266,724	731,489	45	9	46.78	Y	2025	N

Area	Station	Circuit	Circuit Number	Average Yearly CMI for Years 2022-2024	2024 CMI	2022-2024 Average CMI Ranking	2024 CMI Ranking	Total Primary Circuit Miles	Targeted Widening in Proforma Period	Year of Widening Activity	Widening Considered Complete
Ashland	Olive Hill	Globe	3103101	251,849	219,644	47	61	123.94	Y	2025	N
Hazard	Softshell	Vest	3420001	248,937	571,962	48	14	58.23	N	2029	N
Hazard	Slomp	Leatherwood	3309902	247,129	423,507	49	22	70.71	N	2029	N
Ashland	47th Street	49th Street	3008001	244,315	575,231	50	13	25.39	Y	2025	N
Hazard	Collier	Lower Rockhouse	3308602	242,488	418,049	51	23	64.97	Y	2025	N
Pikeville	Garrett	Lackey	3413402	242,052	252,368	52	55	33.94	N	2029	N
Ashland	Big Sandy	Yatesville	3000203	238,405	375,257	53	26	65.97	N	2029	N
Hazard	Softshell	Leburn	3420002	230,597	307,292	54	42	50.55	N	2029	N
Pikeville	Kenwood	Hager Hill	3409303	228,062	214,129	55	63	49.99	N	2029	N
Pikeville	Feds Creek	Feds Creek	3409401	218,303	216,405	58	62	40.59	N	2029	N
Hazard	Reedy	Deane	3311401	191,126	193,402	63	70	43.56	Y	2025	N
Hazard	Mayking	Ermine	3314401	183,324	310,965	64	41	28.21	N	2029	N
Ashland	Cannonsburg	Route 3	3008702	177,811	335,072	66	34	99.2	N	2029	N
Pikeville	Fords Branch	Shelby	3411901	174,363	205,554	67	67	64.73	N	2029	N
Pikeville	Tom Watkins	Upper Pond Creek	3201001	169,813	262,055	69	51	28.06	N	2029	N
Pikeville	Index	West Liberty	3401801	177,858	22,582	65	152	56.53	Y	2025	N
Pikeville	Mayo Trail	Davis Branch	3420103	161,016	257,731	74	54	32.27	Y	2025	N
Pikeville	Mayo Trail	Euclid	3420102	130,815	46,845	89	125	19.48	Y	2025	N
Pikeville	Lovely	Mt Sterling	3202203	100,456	13,126	102	168	13.25	Y	2025	N
Pikeville	Mayo Trail	Nippa	3420101	95,905	54,325	105	121	22.59	Y	2025	N
Pikeville	Index	Hospital	3401802	33,210	13,447	156	166	20.24	Y	2025	N

Project ID	Year Scheduled	PID Start Date	PID End Date	PID Costs in Test Year (CWIP)	Actual Plant Retirements†	Cost of Removal and Salvage‡	Explanation of Variance	Depreciation Impact* (Current Rate @ 3.52%)	Depreciation Impact* (Proposed Rate @ 3.25%)
TREEREL25	2025	1/1/2025	12/31/2025	\$ 3,709,345.50	N/A	N/A	The variance between the project costs in this exhibit and proforma are due the timeframe analyzed. The proforma highlights dollars to be spent in the 12 months after the test year, while the estimated PID costs represent expected charges to the project in the stated calendar year.	\$ 563,200	\$ 520,000
TREEREL26	2026	1/1/2026	12/31/2026	\$ -	N/A	N/A	Variance for this Project ID cannot be determined as no actual dollars have been spent in this PID yet. These projects have not yet started.	\$ 633,600	\$ 585,000
TREEREL27	2027	1/1/2027	12/31/2027	\$ -	N/A	N/A		\$ 880,000	\$ 812,500
TREEREL28	2028	1/1/2028	12/31/2028	\$ -	N/A	N/A		\$ 880,000	\$ 812,500
TREEREL29	2029	1/1/2029	12/31/2029	\$ -	N/A	N/A		\$ 880,000	\$ 812,500

† ROW widening activities target the physical space around distribution circuits rather than a specific piece of distribution equipment. There is no specific asset to retire. As distribution circuits are accounted on a mass property basis, these charges are added to the overhead conductor's property and included in FERC account 365.

‡ Similar to retirements, there is no specific salvage amount for TOR ROW widening. As there are no physical assets to dismantle in the field and distribution circuits are accounted on a mass property basis, these credits are added to the overhead conductor's property and included in FERC account 365.

\* This depreciation amount is added to the conductor property in FERC account 365 on a PID basis, not a circuit by circuit basis.

Capital Funding for TOR Reliability Widening per Year						
Year	2025*	2026	2027	2028	2029	Total Incremental
Project	TREEREL25	TREEREL26	TREEREL27	TREEREL28	TREEREL29	
Funding	\$13,000,000	\$18,000,000	\$25,000,000	\$25,000,000	\$25,000,000	\$106,000,000
	13.00%	18.00%	25.00%	25.00%	25.00%	106.00%

\*Base Funding for 2025 was \$6M

Capital Funding for the Proforma Period by District							
Year	Dates Included	Activity	Project ID	Ashland	Hazard	Pikeville	Total Capital
2025	6/1 - 12/31	ROW Widening	TREEREL25	\$ 1,858,131	\$ 3,716,262	\$ 3,716,262	\$ 9,290,655
2026	1/1 - 5/31	ROW Widening	TREEREL26	\$ 1,654,776	\$ 3,396,645	\$ 3,657,925	\$ 8,709,346
District Totals				\$ 3,512,907	\$ 7,112,907	\$ 7,374,187	\$ 18,000,000

[illegible]

[illegible]



**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 Certain Regulatory And Accounting    )  
Treatments; and (4) All Other Required Approvals    )  
And Relief                                                        )

Case No. 2025-00257

**DIRECT TESTIMONY OF**  
**ROBERT A. JESSEE**  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
ROBERT A. JESSEE ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**DIRECT TESTIMONY OF  
ROBERT A. JESSEE ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is Robert A. Jessee. My position is Vice President of Generating  
3       Assets – East and my business address is 200 Association Drive, Charleston, West  
4       Virginia 25311.

**II. BACKGROUND**

5   **Q.   PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND**  
6       **AND BUSINESS EXPERIENCE.**

7   A.   I hold a Bachelor of Science in Mechanical Engineering from Virginia Tech and  
8       have been employed with American Electric Power Company, Inc. (“AEP”) for  
9       over 25 years. In that time, I have held various positions of increasing responsibility  
10      within AEP. I have worked at several power plants across the AEP system as a  
11      Performance Engineer, Maintenance Superintendent, Operations Superintendent,  
12      and as a Plant Manager. In March of 2023, I was named Managing  
13      Director – Generating Assets for Indiana Michigan Power Company (“I&M”) and  
14      Kentucky Power Company (“Kentucky Power” or the “Company”). I served in that  
15      role until being promoted to Vice President of Generating Assets for Appalachian  
16      Power Company (“Appalachian Power”) and Wheeling Power Company  
17      (“Wheeling Power”) in January 2024. In November 2024, my role was expanded

1 to include support to Kentucky Power and I&M service territories and my title was  
2 updated to Vice President of Generating Assets – East.

3 **Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES**  
4 **AS VICE PRESIDENT GENERATING ASSETS – EAST.**

5 A. I am responsible for the safe, reliable, economic, and environmentally-compliant  
6 operation of the fossil-fueled and hydroelectric generating assets owned and  
7 operated by Appalachian Power and Wheeling Power. These assets include: the  
8 Amos, Mitchell, and Mountaineer coal-fired power plants; the gas-fired Ceredo  
9 (simple-cycle combustion turbines), Clinch River (gas-fired boiler), and Dresden  
10 (combined-cycle) power plants; and Appalachian Power’s hydroelectric facilities.  
11 I also support the fossil-fueled and hydroelectric generating assets that operate  
12 within the Kentucky Power and I&M service territories. This includes the Big  
13 Sandy gas fired boiler power plant and the Rockport coal-fired power plant.  
14 Specifically, I consult, and monitor plant activities, including the operations,  
15 maintenance, and engineering at the plant facilities. Additionally, I support new  
16 generation development as well as any decommissioning, demolition, and  
17 disposition of generating assets owned by the AEP East companies.

18 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
19 **PROCEEDINGS?**

20 A. Yes. I have submitted testimony on behalf of Appalachian Power before the  
21 Virginia State Corporation Commission in Case No. PUR-2024-00024, the West  
22 Virginia Commission in Case Nos. 24-0413-E-ENEC and 24-0854E-42T. I have  
23 also submitted testimony and testified on behalf of I&M before the Michigan Public  
24 Service Commission in Case Nos. U-21053 and U-21461, and I have submitted

1 testimony before the Indiana Utility Regulatory Commission in Cause No. 45933,  
2 I&M's 2023 base rate case.

### III. PURPOSE OF TESTIMONY

3 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
4 **PROCEEDING?**

5 A. The purpose of my Direct Testimony is to:

- 6 • Describe Kentucky Power's generation fleet;
- 7 • Describe and support the reasonableness of Kentucky Power's
- 8 generation non-fuel, non-labor operation and maintenance ("O&M")
- 9 expenses for the Mitchell and Big Sandy Plants; and
- 10 • Describe capital investments placed in-service at Kentucky Power's
- 11 generating assets since the Company's last base rate case.

### IV. KENTUCKY POWER'S GENERATION FLEET

12 **Q. PLEASE DESCRIBE KENTUCKY POWER'S GENERATION FLEET.**

13 A. Kentucky Power owns and operates the Big Sandy Plant located near Louisa,  
14 Kentucky. The plant currently has a single operating unit with a generating capacity  
15 of 295 MW. Big Sandy Unit 1 was originally placed in service in 1963 and operated  
16 as a 278 MW sub-critical coal-fired generating unit through mid-November 2015.  
17 As approved by the Public Service Commission of Kentucky ("Commission") in  
18 Case No. 2013-00430, Big Sandy Unit 1 was converted to a natural gas-fired unit  
19 and returned to service May 31, 2016. The Unit is equipped with low nitrogen oxide  
20 ("NO<sub>x</sub>") burners with overfire air for reduction of NO<sub>x</sub> emissions.

21 The Mitchell Plant is located approximately 12 miles south of Moundsville,  
22 West Virginia on the Ohio River. Kentucky Power owns an undivided 50% interest

1 in the Mitchell Plant; the other 50% interest is owned by Wheeling Power. The  
 2 Mitchell Plant is operated by Wheeling Power. The plant comprises two super-  
 3 critical pulverized coal-fired baseload generating units. Mitchell Unit 1 has a  
 4 capacity of 770 MW and Mitchell Unit 2 has a capacity of 790 MW for a total  
 5 capacity of 1,560 MW. Both Units were placed in service in 1971. A table  
 6 summarizing the fossil generating units is provided below in Figure RAJ-1.

**Figure RAJ-1: Kentucky Power Generation Assets**

Plant Name	Kentucky Power-Owned Capacity (MW)	Unit No.	Location	Fuel Type	In-Service Year	Expected Retirement Date
Big Sandy	295*	1	Louisa, KY	Natural Gas	1963	2041
Mitchell	385*	1	Moundsville, WV	Coal	1971	2040
Mitchell	395*	2	Moundsville, WV	Coal	1971	2040
*Installed Capacity (ICAP) <sup>1</sup>						

7 **Q. HAVE THERE BEEN ANY CHANGES TO THE EXPECTED**  
 8 **OPERATIONAL LIVES OF ANY GENERATING ASSETS SINCE THE**  
 9 **LAST BASE RATE CASE?**

10 A. Yes, per the Company's most recently filed Integrated Resource Plan,<sup>2</sup> the  
 11 Company will operate Big Sandy Unit 1 for an additional 10 years through mid-

<sup>1</sup> Excluding other capacity entitlements (*i.e.*, purchased power) that are used to meet the minimum PJM Planning Reserve Margin requirement, Kentucky Power owns a net generating capacity of approximately 1,075 MW.

<sup>2</sup> Kentucky Power Company's Integrated Resource Planning Report, *In The Matter Of: Electronic 2022 Integrated Resource Planning Report of Kentucky Power Company*, Case No. 2023-00092 (Ky. P.S.C. Mar. 20, 2023).

1           2041. See Company Witness Spanos's depreciation study for the associated  
2           changes to depreciation rates for Big Sandy as a result of this change.

3           **V.       KENTUCKY POWER TEST YEAR GENERATION O&M**

3   **Q.       WHAT ARE THE O&M REQUIREMENTS OF KENTUCKY POWER'S**  
4   **GENERATION ASSETS?**

5   A.       Kentucky Power's generating plants must provide safe, reliable, economic, and  
6           environmentally-compliant generation output to serve load and accommodate  
7           fluctuating customer needs. In addition, a unit's maintenance needs vary based on  
8           its type, design, age, condition, and operational characteristics. All units are  
9           maintained to maximize operations, and to do so in a safe manner in compliance  
10          with all local, state, and federal regulations.

11 **Q.       WHAT GENERATION O&M EXPENSE ARE YOU SUPPORTING IN**  
12 **THIS PROCEEDING?**

13 A.       I am supporting Kentucky Power's non-fuel, non-consumables, non-labor test year  
14           (historical 12-month period ending May 31, 2025) ("Generation O&M"). The test  
15           year amount of that Generation O&M expense is \$26.840 million.

16 **Q.       PLEASE EXPLAIN WHAT MAKES UP THE GENERATION O&M**  
17 **EXPENSES.**

18 A.       Non-fuel generation O&M expense includes costs associated with the operation,  
19           maintenance, administration, and support of Kentucky Power's generating units.  
20           These costs exclude fuel and labor but include material and supplies, contractor  
21           services, and other miscellaneous expenses for the generating facilities.

22                 Generation O&M expense includes base cost of operation expenses  
23           involved in normal operation and maintenance that are relatively consistent from

1 year-to-year. An example would include maintenance on parts and equipment that  
2 is typically routine and predictable. This would include environmental fees,  
3 chemicals related to water chemistry, and maintenance and operating cost related  
4 to critical system components such as the circulating water, pretreatment, building  
5 and grounds, material handling, fire protection, pulverizers, high pressure heaters,  
6 main steam and safety valves.

7           Planned Outages also represent a portion of the Generation O&M expense.  
8 Planned outages are outages that can include repair and major overhaul of large  
9 systems and components such as the boiler, turbine, or generator. These types of  
10 outages are scheduled and planned months or years in advance and often require  
11 long lead times on equipment and engineering of new or replacement components.

12           The Forced and Opportunity Outage category includes unplanned and  
13 unscheduled outages that require the unit to be taken offline because of an  
14 unanticipated event or failure. And finally, the non-outage maintenance  
15 improvement (“NOMI”) category of Generation O&M expense represents notable  
16 maintenance work that can be performed while the generating unit remains in  
17 service. Examples include items such as crane inspection and repairs, gearbox  
18 repairs, valve repairs, tank inspection and repairs, stack inspection and repairs,  
19 barge unloader inspection and repairs, bridge inspection and repairs, and river cells  
20 inspection and repairs.

21           As shown in Figure RAJ-2 below, Kentucky Power’s test year Generation  
22 O&M expenses include steam maintenance and steam operations amounts for Big  
23 Sandy, the Company’s 50% undivided interest in Mitchell, and shared plant costs  
24 not attributable to a specific generating unit (known as Non-Plant costs).



**RAJ-2: Kentucky Power's Non-Fuel, Non-Consumables, Non-Labor Test  
Year Generation O&M\***

<b>Category</b>	<b>Big Sandy Plant</b>	<b>Mitchell Plant</b>	<b>Non-Plant</b>	<b>Total</b>
Steam Maintenance	\$4,377,198	\$15,738,018	(\$649,117)	\$19,466,099
Steam Operations	\$1,469,869	\$4,604,678	\$1,229,008	\$7,373,555
<b>Total Test Year Generation O&amp;M:</b>	\$5,847,067	\$20,342,696	\$649,891	\$26,839,654

\*Total may not sum due to rounding

1 **Q. WHY DID THE TEST YEAR STEAM MAINTENANCE NON-PLANT**  
2 **COSTS SHOW A CREDIT?**

3 A. The negative account balance is a function of the timing of monthly accounting  
4 accruals and reversals. At the end of the test year, the net of these transactions over  
5 the 12-month period resulted in a negative balance.

6 **Q. DOES THE TOTAL TEST YEAR AMOUNT OF \$26.840 MILLION**  
7 **REPRESENT AN APPROPRIATE AND REASONABLE ONGOING**  
8 **LEVEL OF GENERATION O&M FOR KENTUCKY POWER'S**  
9 **GENERATION ASSETS?**

10 A. Yes. Based on my experience and analysis of historical information, the test year  
11 level is reasonable and fairly reflects an appropriate level of Generation O&M for  
12 Big Sandy and Kentucky Power's undivided 50% share of the Mitchell Plant. In  
13 general, the variable nature of Generation O&M is driven by such things as unit  
14 outages, both planned and unplanned, as well as periodic scheduled repairs and  
15 replacements of unit components. The test year value aligns with historical O&M  
16 expenses as well as currently known and anticipated operational and maintenance  
17 activities.

1                    Additionally, as shown in Figure RAJ-3 below, the test year level of  
 2                    Generation O&M is fairly consistent with the test year levels of Generation O&M  
 3                    from the Company's most recent base rate case proceedings and, as compared to  
 4                    the Company's 2023 base rate case test year, reflect an overall reduction to total  
 5                    Generation O&M.

**RAJ-3: Kentucky Power's Historical Non-Fuel, Non-Consumables,  
Non-Labor Test Year Generation O&M\***

Case No.	Big Sandy Plant	Mitchell Plant	Non-Plant	Total O&M
2017-00179	\$6,223,221	\$15,906,533	\$1,767,872	\$23,897,626
2020-00174	\$5,657,278	\$15,518,042	\$1,536,275	\$22,711,595
2023-00159	\$7,524,734	\$17,319,946	\$2,841,984	\$27,633,897
2025-00257	\$5,847,067	\$20,342,696	\$649,891	\$26,839,654

\*Total may not sum due to rounding

6    **Q.    PLEASE DESCRIBE ANY PROCESSES, SUCH AS BUDGETING,**  
 7                    **PLANNING, AND COST REVIEW, WHICH ARE USED TO CONTROL**  
 8                    **GENERATION O&M COSTS.**

9    A.    Kentucky Power's generation planning and budgeting is a cohesive and dynamic  
 10                    planning process that is linked to the annual business planning process. Kentucky  
 11                    Power management reviews any variances between actual O&M expense and,  
 12                    where possible, adjusts spend to keep O&M expenditures within budget. A  
 13                    competitive bidding process is used when appropriate for selecting contractors to  
 14                    perform maintenance, inspection, and procurement of the necessary equipment and  
 15                    materials. This approach helps to manage costs effectively while maintaining high  
 16                    standards of safety and reliability.

1 Kentucky Power also relies on maintenance and operations management  
2 programs to ensure optimal performance of the generating assets. These  
3 maintenance programs are predictive maintenance and preventative maintenance.  
4 Predictive maintenance consists of monitoring, inspections, and data analyses  
5 conducted to diagnose potential maintenance issues early and usually while the  
6 equipment is running to minimize downtime. Preventive maintenance consists of  
7 scheduled protocols, testing, and physical work conducted on equipment to address  
8 anticipated or diagnosed vulnerabilities.

9 In addition, continuous improvements are incorporated into the operations  
10 and maintenance of the generating units to eliminate waste and increase process  
11 efficiencies. Together, these maintenance and operations management programs  
12 help to optimize operation of the assets and limit O&M cost escalations.

13 **Q. CAN YOU DESCRIBE UPGRADES AT THE MITCHELL AND BIG**  
14 **SANDY PLANTS WHICH HAVE REDUCED O&M AND IMPROVED**  
15 **RELIABILITY?**

16 A. Mitchell Unit 1 improvement activities include:

- 17 • Replacing the turbine rotor and the generator gas baffles;
- 18 • Repairing the precipitators based on internal inspections;
- 19 • Updating the Induced Draft (“ID”) fans; and
- 20 • Repairing the steam generator internals.

21 Mitchell 2 improvement activities include:

- 22 • Repairing precipitator internal;
- 23 • Repairing steam generator internals; and

- Replacing ID fan hub components.

Big Sandy Unit 1 improvement activities include:

- Replacing 30 breakers on the 600 volt switchgear;
- Replacing the boiler feed pump rotor assembly; and
- Upgrading the circulating water facilities.

These upgrades will reduce plant outages, improve plant reliability and allow the plants to operate more efficiently, thereby reducing the Generation O&M required to run the plants.

## **VI. GENERATION CAPITAL ADDITIONS**

**Q. PLEASE PROVIDE AN OVERVIEW OF GENERATION CAPITAL ADDITIONS BEING REQUESTED TO BE INCLUDED IN RATE BASE.**

A. Kentucky Power made steam and other generation plant related capital additions totaling approximately \$71.451 million since the Company's last base rate case. Of that amount, \$15.885 million is associated with major fossil fuel generation capital projects and \$9.981 million 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 \$1.285 million. General capital additions that support plant operations account for approximately \$418,000. The remaining fossil fuel generation capital amounts include Asset

1 Retirement Obligation (“ARO”) estimates that resulted in an increase of  
 2 approximately \$22.805 million to capital additions.

3 Figure RAJ-4 provides a summary of generation capital additions since the  
 4 last base rate case proceeding and includes projects that have been approved for  
 5 recovery through the Company’s environmental surcharge as discussed further by  
 6 Company Witness Cullop.

**Figure RAJ-4 - Generation Capital Additions<sup>3</sup>**  
**April 2023–May 2025**

<b>Plant</b>	<b>Project Description</b>	<b>Addition to Plant (\$)</b>
<b>Big Sandy Plant</b>	<b>Fossil Fuel Major Projects</b>	
	<b>(Non-Environmental)</b>	
	Big Sandy Unit 1 Boiler Exit Gas Duct Replacement	\$9,166,039
	<b>Big Sandy Fossil Fuel Major Project Subtotal:</b>	<b>\$9,166,039</b>
	<b>Other Fossil Generation Capital Projects</b>	
	Production Plant Blanket Projects:	\$3,964,065
	Non-Environmental Blanket	\$4,049,332
	Environmental Blanket	(\$85,267)
	<b>Big Sandy Other Fossil Generation Capital Projects Subtotal:</b>	<b>\$3,964,065</b>
<b>Big Sandy Plant Total</b>		<b>\$13,130,104</b>
<b>Mitchell Plant (Kentucky Power Share)</b>	<b>Fossil Fuel Major Projects</b>	
	<b>(Environmental)</b>	
	Mitchell Unit 0 CCR Compliance	\$21,077,061
	Mitchell Unit 0 Dry Sorbent Injection (DSI) Lime Conversion	\$1,786,830
	Mitchell Unit 0 Landfill Haul Road Relocation	\$960,536
	Mitchell Unit 2 Electrostatic Precipitator (ESP) Upgrades	\$45,291
	Mitchell Unit 2 Selective Catalytic Converter (SCR) Catalyst Layer 4 Replacement	\$1,064

<sup>3</sup> These amounts do not include ELG investment associated with the Mitchell Plant, that is subject to the Company’s pending case in 2025-00175.

Plant	Project Description	Addition to Plant (\$)
		<b>\$23,870,782</b>
	<b>(Non-Environmental)</b>	
	Mitchell Unit 1 Air Heater Basket Replacement	\$1,450,255
	Mitchell Unit 1 Cooling Tower Components Replacement	\$1,351,270
	Mitchell Unit 1 Cooling Tower Canopy Beam Replacements	\$629,644
	Mitchell Plant Unit 1 Very High Pressure/High Pressure and Low Pressure Turbine 'A' Inspections	\$589,671
	Mitchell Unit 2 Cooling Tower Components Replacement	\$20,952
	Mitchell Unit 2 Air Heater Basket Replacement	(\$116,909)
		<b>\$3,924,881</b>
	<b>Mitchell Plant Fossil Generation Capital Project Subtotal:</b>	<b>\$27,795,663</b>
	<b>Other Fossil Generation Capital Projects</b>	
	Production Plant Blanket Projects:	\$6,016,828
	Non-Environmental Blanket	\$4,091,437
	Environmental Blanket	\$1,925,391
	ARO ASH - ELG Mitchell Plantwide	\$4,643,038
	ARO #5 Mitchell Ash CCRMU	\$4,439,809
	ARO #3 Mitchell Landfill	\$3,600,892
	ARO #4 Mitchell Wastewater Pond	\$1,950,148
	ARO #1 Mitchell Ash Pond	\$76,434
	ARO #1 Connor Ash Pond, Mitchell Plant	(\$1,105,799)
	<b>Mitchell Other Fossil Generation Capital Project Subtotal:</b>	<b>\$19,621,351</b>
<b>Mitchell Plant Total</b>		<b>\$47,417,014</b>
<b>Various Facilities</b>	ARO ASH - ELG Kammer Plantwide	\$9,200,584
	Intangible Capital Projects	\$1,285,340
	General Capital Projects	\$418,281
<b>Various Facilities Total</b>		<b>\$10,904,205</b>
<b>Total Kentucky Power Capital Additions</b>		<b>\$71,451,323</b>

1   **Q.     PLEASE SUMMARIZE THE INDIVIDUAL FOSSIL FUEL GENERATION**  
2       **CAPITAL ADDITIONS OVER \$1 MILLION INCLUDED IN FIGURE**  
3       **RAJ-4 AND EXPLAIN WHY THEY WERE NECESSARY.**

4   A.     The capital additions over \$1 million are described below.

**Mitchell Capital Projects Over \$1 Million**

5       Non-Environmental

- 6           •   Mitchell Unit 1 Cooling Tower Components: A portion of the Cooling  
7               Tower components at Mitchell Unit 1 had reached the end of their useful  
8               life after 30 years of service and others had deteriorated to a point where  
9               they would not provide reliable service with continued operation. This  
10              project replaced the Hot Water Distribution deck, louvers and louver  
11              columns, outer periphery longitudinal girts, and other associated  
12              components.
- 13          •   Mitchell Unit 1 Air Heater Basket Replacement: The air heater baskets  
14               were one year beyond their typical life cycle and were beginning to  
15               deteriorate exponentially. As a result, Mitchell Unit 1 was beginning to  
16               experience increases in its equivalent forced outage rate associated with  
17               the baskets. The existing air heater baskets have been replaced with new  
18               air heater baskets.

19       Environmental

- 20          •   Mitchell Plant Dry Sorbent Injection (“DSI”) Lime Conversion  
21               Upgrades: Mitchell Plant previously used Trona for SO<sub>3</sub> mitigation. The  
22               project reconfigured the existing DSI system for Mitchell Units 1 and 2  
23               to more efficiently handle hydrated lime in lieu of Trona, and reduce

1 issues related to corrosion, as well as gain benefits such as heat rate  
2 improvement, improved Equivalent Unplanned Outage Rate, and a  
3 lower minimum load. Conversion to lime also allows for the use of a  
4 higher percentage of high sulfur coal which has historically been  
5 cheaper than the lower sulfur coal, thereby resulting in lower overall  
6 fuel costs. The project also installed a new distributed control system  
7 for the DSI.

- 8 • Mitchell Plant Coal Combustion Residual (“CCR”) Compliance: In  
9 order to comply with the CCR Rule, Kentucky Power and Wheeling  
10 Power removed ash from the existing ponds, over-excavated the ponds  
11 to ensure closure by removal, installed a new liner system in the  
12 footprint of the existing bottom ash pond to accept current CCR and  
13 non-CCR wastewater streams, and installed a chemical treatment  
14 system for non-CCR wastewater streams. Kentucky Power and  
15 Wheeling Power also have installed larger clinker grinders on Mitchell  
16 Unit 1 for improved bottom ash removal. Mitchell Unit 2 will receive  
17 similar upgrades during 2026. Additionally, the bottom ash handling  
18 systems were modified to no longer allow the discharge of bottom ash  
19 transport water, including the installation of submerged grind conveyor  
20 systems, and a new ash bunker.

### **Big Sandy Capital Projects Over \$1 Million**

#### **Non-Environmental**

- 22 • Boiler Exit Gas Duct Replacement: The exit gas duct was originally  
23 installed in 1969 and had portions patched many times throughout the



1 years due to leaks. During the conversion from coal to natural gas, the  
2 duct was significantly modified in place to remove the precipitator  
3 internals and associated coal/ash handling related equipment. Recent  
4 evaluations showed structural integrity issues which warranted the  
5 replacement of the duct.

6 Environmental

- 7 • No Major Projects

8 **Q. WHAT ARE PLANT PRODUCTION BLANKET (“PPB”) PROJECTS?**

9 A. PPB projects are capital projects necessary to provide the safe, reliable, economic,  
10 and environmentally-compliant operation of the Company’s generating units that  
11 fit into blanket projects because they either are new equipment or are total  
12 replacement of an existing piece of equipment at the plant. These projects are  
13 placed into two categories, major or minor. Major plant blanket projects will have  
14 a total cost of over \$1 million but under \$3 million. Minor plant blanket installations  
15 are projects that have a total cost of \$1 million or below.

16 When evaluating these PPB projects, Kentucky Power looks for cost  
17 savings whenever possible without jeopardizing reliability and safety. All PPB  
18 projects over \$1 million (major PPBs) are reviewed and approved by Kentucky  
19 Power management.

20 **Q. PLEASE DESCRIBE SOME OF THE PPB CAPITAL ADDITIONS OVER**  
21 **\$1 MILLION SINCE APRIL 1, 2023, AT KENTUCKY POWER’S POWER**  
22 **PLANTS THAT ARE INCLUDED IN RATE BASE.**

23 A. The major PPB projects for the Big Sandy and Mitchell Plants are listed below:

1        Mitchell Plant Major PPB Capital Projects

- 2                • Mitchell Unit 1 and 2: There were no major individual PPB items over  
3                \$1 million, but the replacement of the burner nozzles, plant air dryers,  
4                and soot-blowers on both units totaled approximately \$600,000. These  
5                projects were necessary as the components had reached the end of their  
6                useful life and when not properly functioning impacts operation of the  
7                unit and or facility. Burner nozzles serve the function of distributing  
8                pulverized coal and air into the boiler for combustion. These  
9                components are subject to wear and tear, and their proper functioning is  
10               essential for ensuring complete and stable combustion, ultimately  
11               impacting the unit's ability to achieve full load, efficiency, and achieve  
12               emissions limits. Air dryers are essential components of the plant air  
13               system, particularly for instrument air and combustion air. They remove  
14               moisture from the compressed air to prevent corrosion, freezing, and  
15               operational issues in pneumatic equipment and control systems. Soot  
16               blowers in coal-fired power plants are crucial for maintaining boiler  
17               efficiency by removing soot and ash deposits from furnace walls and  
18               heat transfer surfaces. These devices use a jet of steam to dislodge these  
19               deposits, preventing them from hindering heat transfer and reducing the  
20               overall performance of the boiler.

21        Big Sandy Major PPB Capital Projects

- 22                • Big Sandy Unit 1: Although there were no major individual PPB items  
23                over \$1 million, the replacement of all the 600-volt breakers on the "A"  
24                Bus and "B" Bus totaled approximately \$1.89 million. The breakers

1                   were original to the plant and repair parts were obsolete. Replacement  
2                   of the breakers increased the reliability of the unit.

3   **Q.    HAVE THE UPGRADES PERFORMED ON THE MITCHELL UNITS**  
4       **EXTENDED THE ABILITY OF MITCHELL TO CONTINUE TO**  
5       **OPERATE AS A COAL PLANT AFTER DECEMBER 31, 2028?**

6   A.    Yes. As further explained by Company Witness Wolfram, in reference to the ELG  
7       upgrade, several of the capital projects listed in Figure RAJ-3, have been completed  
8       at the Mitchell Plant since this Commission's Orders in Case No. 2021-00004 and  
9       Case No. 2021-00421 that required the termination of the Company's interest in  
10      energy and capacity from the Mitchell Plant after December 31, 2028. Each of the  
11      capital projects that were completed to extend the ability of the Mitchell Plant to  
12      operate as a coal plant past 2028 were allocated asymmetrically to Wheeling Power  
13      beginning in September 2022. Kentucky Power has filed an application in Case No.  
14      2025-00175 to make the investments necessary investment to continue taking 50%  
15      of the energy and capacity of the Mitchell Plant after December 31, 2028.

16   **Q.    PLEASE SUMMARIZE THE INTANGIBLE CAPITAL INVESTMENTS**  
17       **THAT ARE INCLUDED IN RATE BASE.**

18   A.    Allocations to Kentucky Power's fossil fuel generation organization for intangible  
19      projects which include routine software updates and new programs that increase the  
20      efficiency of Kentucky Power's Generation organization, account for  
21      approximately \$1.3 million. It is important to note that a majority of these costs  
22      stem from a few key projects, one of which involves cloud computing upgrades and  
23      software upgrades utilized in plant analysis and efficiency.

**VII. CONCLUSION**

1    **Q.    DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2    A.    Yes. The total test year O&M amount is reasonable and comparable to previous test  
3        years amounts. The capital upgrades incurred between rate changes, to be included  
4        in rate base, are reasonable and needed to maintain the safe, efficient, reliable, and  
5        economic operation of the facilities and should be approved.

## VERIFICATION

The undersigned, Robert A. Jessee, being duly sworn, deposes and says he is the Vice President of Generating Assets East 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.

Robert A. Jessee  
Robert A. Jessee

State of West Virginia )  
 )  
County of Kanawha )

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert A. Jessee, on August 21, 2025.

Maisha T. Staples  
Notary Public

My Commission Expires November 23, 2026

Notary ID Number 319345



**DIRECT TESTIMONY OF**

**STEVIN. 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. 2025-00257**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT SNC-1	FlexPay Program Tariff
EXHIBIT SNC-2	FlexPay Daily Customer Charge
EXHIBIT SNC-3	FlexPay Program Customer Communication Examples
EXHIBIT SNC-4	FlexPay Customer Statement Draft

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

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is Stevi N. Cobern, and I am a Regulatory Consultant Principal for Kentucky  
3       Power Company (“Kentucky Power” or the “Company”). My business address is 1645  
4       Winchester Avenue, Ashland, Kentucky 41101.

**II. BACKGROUND**

5   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
6       **BUSINESS EXPERIENCES.**

7   A.   I received a Regents Bachelor of Arts degree from Marshall University in Huntington,  
8       West Virginia in 2022. In 2002, I began working for American Electric Power (“AEP”) in  
9       AEP’s Customer Operations Center. In 2009, I joined Kentucky Power, working in various  
10      departments including meter revenue operations and forestry. I transitioned back to  
11      customer service in 2018 as Customer Services Coordinator and then in May 2021 was  
12      promoted to Customer Services Supervisor. In September 2024, I accepted my current  
13      position as Regulatory Consultant Principal.

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

16   A.   My primary responsibility is to support the Company’s regulatory activities. Additionally,  
17       I am responsible for the administration of Kentucky Power’s Home Energy Assistance



1 (“HEA”) programs, which includes the Home Energy Assistance in Reduced Temperatures  
2 (“HEART”), Donation HEART, and Temporary Heating Assistance in Winter (“THAW”)  
3 programs. I also address customer inquiries from the Public Service Commission of  
4 Kentucky (“Commission”), Office of the Attorney General, and Better Business Bureau  
5 ensuring timely investigation and response to such inquiries.

6 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
7 **PROCEEDINGS?**

8 A. Yes. I have submitted testimony before this Commission in Case No. 2019-00366  
9 (Commission’s investigation of investor-owned utilities’ HEA programs), Case No. 2023-  
10 00159 (the Company’s previous base rate case), Case No. 2024-00115 (the Company’s  
11 most recent demand side management case), and Case No. 2024-00344 (the Company’s  
12 application for a certificate of public convenience and necessity to install Advanced  
13 Metering Infrastructure (“AMI”)).

### **III. PURPOSE OF TESTIMONY**

14 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
15 **PROCEEDING?**

16 A. The purpose of my Direct Testimony is to support the Company’s proposal for the  
17 Kentucky Power FlexPay Program for AMI customers (“FlexPay”). Additionally, my  
18 Direct Testimony covers the following topics:

- 19 • Maintaining the current funding level for the residential energy assistance  
20 (“REA”) surcharge;

- Maintaining the current funding level for the Kentucky Economic Development Surcharge Tariff (“Tariff K.E.D.S.”) that supports the Kentucky Power Economic Growth Grant (“K-PEGG”) program; and
- Supporting changes to the Company’s Tariffs and Terms and Conditions, including new tariff proposals and modifications to several existing tariffs.

**Q. ARE YOU SPONSORING ANY EXHIBITS?**

A. Yes. I am sponsoring the following exhibits:

- Exhibit SNC-1 – FlexPay Program Tariff
- Exhibit SNC-2 – FlexPay Daily Customer Charge
- Exhibit SNC-3 – FlexPay Program Customer Communication Examples
- Exhibit SNC-4 – FlexPay Customer Statement Draft

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

A. Yes.

#### **IV. FLEXPAY**

**Q. WILL THE COMPANY BE PROVIDING ANY NEW TARIFF OFFERINGS IN CONNECTION WITH ITS AMI DEPLOYMENT?**

A. Yes. The Company is proposing the FlexPay program, which is a voluntary prepayment program associated with its AMI deployment. FlexPay allows customers to pay as they go, providing them with greater control over the frequency and timing of their payments.

1   **Q.   PLEASE PROVIDE AN OVERVIEW OF KENTUCKY POWER'S FLEXPAY**  
2   **PROGRAM.**

3   A.   FlexPay is a voluntary payment option designed for customers to prepay for their  
4   electricity. The key features of FlexPay include:

- 5       •   Pay-As-You-Go: Customers can pay for their electricity in advance, allowing for  
6           more flexible payment options;
- 7       •   No Deposits: Unlike traditional post-pay billing, FlexPay eliminates the need for  
8           deposits; and
- 9       •   Greater Control: Customers have increased control over the frequency and timing  
10          of their payments, which can enhance their understanding of energy consumption.

11       FlexPay aims to empower customers with more choices and create transparency in  
12       managing their electricity usage and expenses.

13   **Q.   WHAT ARE THE BENEFITS OF THE FLEXPAY PROGRAM?**

14   A.   The FlexPay Program provides customers of Kentucky Power with enhanced options  
15       regarding the timing and method of their electric service payments. With a variety of  
16       payment choices available, customers can select methods and schedules that best fit their  
17       personal circumstances. They can opt for smaller, more frequent payments that align with  
18       their cash flow, rather than a single larger monthly payment. This pre-pay program not  
19       only helps customers avoid unexpected high bills but also offers increased flexibility in  
20       various situations.

21           For example, roommates sharing electricity expenses can set up different payment  
22       arrangements, allowing each person to contribute to the account. Landlords managing  
23       rental properties can keep the account in their names without the risk of accumulating a

1 large balance. Additionally, individuals who assist family members with their electric bills  
2 can easily monitor usage and account balances while having a convenient way to make  
3 payments as needed. In these cases, all parties can receive daily notifications via text or  
4 e-mail about account balances, ensuring everyone stays informed throughout the month.

5 Also, as mentioned earlier, FlexPay allows participants to bypass deposits. This  
6 flexibility removes barriers for new customers who would usually need to pay deposits to  
7 initiate electric service, and helps existing customers stay current on their payments. By  
8 removing this extra fee, overall account balances can decrease, which benefits all  
9 customers by potentially lowering bad debt.

10 Moreover, FlexPay allows participants to gain a better understanding of the  
11 relationship between their energy usage and costs, leading to greater control over their  
12 energy consumption and potential savings. In other words, customers gain clearer insights  
13 into how much their electricity usage costs, enabling them to manage their energy  
14 consumption more effectively. Furthermore, customers with an outstanding balance who  
15 enroll in FlexPay can efficiently address their previous balance, which will be explained  
16 further below.

17 **Q. WHO IS ELIGIBLE TO PARTICIPATE IN THE FLEXPAY PROGRAM AND**  
18 **WHEN WILL ENROLLMENT BEGIN?**

19 A. Kentucky Power's FlexPay program will be available to all residential services equipped  
20 with an AMI meter, except for those under Schedule Residential Demand-Metered  
21 ("R.S.D."). Additionally, customers with specific medical or life-threatening conditions,  
22 those on partial payment plans, Average Monthly Payment ("AMP") plan participants,

1 Equal Payment Plan (“Budget”) customers, and customers with on-site generation  
2 operating in parallel with the Company’s system are ineligible.

3 The Company plans to begin installing AMI meters in the third quarter of 2026,  
4 following completion of installation of the required communication network infrastructure.  
5 Customers can enroll in FlexPay once meter installation is completed at their residence.

6 **Q. WHAT RATE SCHEDULE WILL APPLY TO FLEXPAY CUSTOMERS?**

7 A. FlexPay customers will be billed according to their existing applicable tariff with portions  
8 of the rate converted to a daily rate. Essentially, the standard tariff will serve as the  
9 foundation for the bill calculation. It will be based on the customer’s daily usage over a  
10 24-hour period, the effective base rate, the tax rate, and all applicable riders and fees at the  
11 time energy is consumed. Fixed charges will be charged daily and prorated based on  
12 one-thirtieth of the total fixed charge. These amounts will be deducted from the customer’s  
13 daily account balance. Exhibit SNC-1 provides a copy of the FlexPay Program Tariff.

14 A comparison of FlexPay to post-pay billing is outlined in Figure SNC-1. The  
15 initial \$40 payment is not a fee; it contributes to the FlexPay account balance, roughly  
16 covering nearly one week’s service at a daily rate of \$7.00 for an average residential  
17 customer.

<b>Figure SNC-1</b>		
<b>Comparison Category</b>	<b>Traditional Post-Pay Billing</b>	<b>FlexPay Billing</b>
Timing of Payments	<ul style="list-style-type: none"> <li>Energy billed and paid after consumption</li> </ul>	<ul style="list-style-type: none"> <li>Daily bill amounts are subtracted from the account balance each day</li> </ul>
Account Establishment	<ul style="list-style-type: none"> <li>Deposit required</li> </ul>	<ul style="list-style-type: none"> <li>No deposit required</li> <li>Initial payment of \$40</li> </ul>
Fee Requirements	<ul style="list-style-type: none"> <li>Reconnection fees (for customers with AMR meter)</li> </ul>	<ul style="list-style-type: none"> <li>No reconnection fees</li> </ul>
Debt/Customer Balances	<ul style="list-style-type: none"> <li>Service disconnection occurs after a notice period, during which credit is extended, accumulating debt</li> </ul>	<ul style="list-style-type: none"> <li>Service disconnected the next business day after balance reaches \$0.00</li> </ul>
Service Reconnect	<ul style="list-style-type: none"> <li>After disconnection, customer pays balance owed plus reconnection fee (for customer with AMR meter)</li> <li>Reconnect time (for customer with AMR meter) is typically several hours following receipt of payment</li> </ul>	<ul style="list-style-type: none"> <li>Customer reconnected within 15 minutes following positive account balance</li> </ul>
<p>Note: Termination notices generate the day after a new monthly bill is issued for customers who have a past due balance and are eligible for termination. This timeframe allows on average 30 days following the original bill issue date before a termination notice is generated. The termination notice provides 15 calendar days from the date the notice is issued before service termination.</p>		

**Q. IS FLEXPAY COMPATIBLE WITH THE PROPOSED RESIDENTIAL SERVICE TARIFF WHICH INCORPORATES A TIERED CUSTOMER CHARGE?**

A. Yes. FlexPay is compatible with the proposed residential service tariff. Once a customer's usage exceeds 2,000 kWh in a billing cycle, the full difference between the two customer charges along with the standard daily prorated customer charge, will be deducted from their FlexPay balance the subsequent day. For the remainder of the billing cycle, the customer will continue to pay the prorated daily customer charge rate, calculated from the lower tier.

1 Please refer to Exhibit SNC-2 which shows the daily customer charge rates for tier one and  
2 tier two applicable to FlexPay customers.

3 To ensure customers understand the increase in the customer charge once usage  
4 exceeds 2,000 kWh, the Company will issue a separate alert to FlexPay customers once  
5 their usage exceeds a threshold of 1,500 kWh. This proactive communication empowers  
6 customers to adjust their usage, creating the opportunity to maintain the current customer  
7 charge rate.

8 **Q. HOW WILL CUSTOMERS ENROLL IN THE FLEXPAY PROGRAM?**

9 A. Eligible customers can enroll by calling Kentucky Power's Customer Operations Center.  
10 Customers must meet certain requirements before enrolling in the program. Below are three  
11 scenarios that illustrate the enrollment process:

12 New Account: A customer setting up a new account must make an initial payment of \$40  
13 to enroll in the program. This payment is required to fund the FlexPay account but is  
14 immediately available to be applied toward electric usage. New customers do not need to  
15 pay a deposit. The initial payment must be completed within two days of enrollment;  
16 otherwise, the customer will automatically switch back to the standard post-payment  
17 option.

18 Existing customer with deposit and no arrears balance: An existing customer with a deposit  
19 who wants to enroll in FlexPay will also need to make an initial payment of \$40. However,  
20 if the deposit credit is enough to cover this amount, the customer will not need to make an  
21 additional payment. Any remaining deposit balance will be applied to the FlexPay account  
22 for future electric usage.

Existing customer with a deposit and arrears amount: Customers with a deposit and a past due balance must pay any outstanding amount over \$500 in addition to the initial \$40 payment to enroll in FlexPay. The customer's deposit can be credited toward this required payment. The remaining balance, up to \$500, will be carried into an arrears amount that will be paid with each future payment at an 80/20 split: 80% will be applied to the FlexPay balance, and the remaining 20% will be applied to the arrears amount. Figure SNC-2 summarizes these enrollment scenarios.

**Figure SNC-2**

<b>Scenario</b>	<b>Deposit</b>	<b>Initial Payment</b>	<b>Payments Going Forward</b>
<b>New Customer</b>	No deposit required.	\$40 initial FlexPay payment.	No required amount for future payments. Customers are only required to keep a positive balance.
<b>Existing Customer with deposit and no past due amount</b>	Existing deposit will be applied to customer's account as a credit.	\$40 initial FlexPay payment. If deposit credit is sufficient to cover the \$40, no other payment is necessary.	No required amount for future payments. Customers are only required to keep a positive balance.
<b>Existing Customer with deposit and a past due amount</b>	Existing deposit will be applied to customer's account as a credit.	Customers can defer up to \$500. Required to pay any prior balance over \$500 plus \$40 initial FlexPay payment. However, the customer's deposit will apply to the required balance.	No required amount for future payments. Customers are only required to keep a positive balance.



**Q. HOW WILL KENTUCKY POWER COMMUNICATE ACCOUNT INFORMATION WITH FLEXPAY CUSTOMERS?**

A. During the FlexPay program enrollment process, customers must select at least one preferred method for receiving communications related to the FlexPay program. Options for communication include e-mail, text, or both. In addition to their chosen communication method, customers can easily check their account balance by calling the Customer Operations Center, using an Interactive Voice Response (“IVR”) system, logging into their account at [kentuckypower.com](http://kentuckypower.com), or via the Company’s mobile app. Customers are responsible for keeping their contact information current to maintain their enrollment in the program. If Kentucky Power cannot reach a customer via e-mail or text, a letter will be sent, informing they have 30 days to select a communication method to remain in the program. If the customer does not update their means of communication, the customer will be switched to traditional post-pay billing. Customers will receive details about this requirement during enrollment.

Additionally, participants must select a low-balance amount of at least \$25 for notification purposes. This low balance notification is solely for alerting customers and does not represent a minimum balance required to maintain electric service.<sup>1</sup> The customer will be notified when the account balance reaches the customer-selected low balance notification amount, or the amount of \$25, whichever is greater. Daily alerts will continue until the balance exceeds the low-balance threshold. For example, if a customer starts with a balance of \$100 and sets a low-balance notification amount of \$25, they will receive an

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<sup>1</sup> The customer must at least maintain an account balance greater than zero to continue receiving electric service.

1 alert when the account balance reaches \$25 and every day thereafter until the account  
2 balance exceeds \$25.

3 Beyond individual notifications, FlexPay participants can access a customer  
4 platform that offers insights into their energy usage and costs during the billing period,  
5 helping them manage their energy expenses efficiently. Lastly, customers can change their  
6 preferred communication method and low-balance notification amount at any time by  
7 visiting [kentuckypower.com](http://kentuckypower.com) or by contacting the Customer Operations Center.

8 **Q. WHAT HAPPENS WHEN A PARTICIPANT'S ACCOUNT BALANCE REACHES**  
9 **ZERO?**

10 A. Customers will receive notifications through their chosen communication method when  
11 their account balance hits zero, along with daily updates on their balance status. They will  
12 have until the beginning of the next business day to make a payment and restore a positive  
13 account balance. If no payment is made, the customer's meter will be automatically  
14 disconnected during regular business hours, which are 8:00 a.m. to 5:00 p.m. from Monday  
15 to Thursday, and 8:00 a.m. to noon on Friday, excluding Company-recognized holidays.  
16 Customers must ensure their payment covers any charges incurred during weekends,  
17 holidays, and moratorium periods. For example, if a customer has a positive balance on a  
18 Thursday but their balance turns negative over a holiday weekend, they will receive a  
19 disconnection notice on Monday. The actual disconnection of service will occur on  
20 Tuesday unless the customer makes a payment sufficient to restore a positive account  
21 balance.

1 **Q. HOW WILL SERVICE BE RECONNECTED FOLLOWING DISCONNECTION**  
2 **FOR AN INSUFFICIENT BALANCE?**

3 A. After disconnection, a participant must restore a positive account balance through an  
4 authorized payment method. Electric service will then be automatically reconnected,  
5 usually within 15 minutes after the payment is processed. Aside from achieving a positive  
6 balance, there are no minimum payment requirements, and customers will not incur any  
7 reconnection or late fees.

8 **Q. PLEASE DESCRIBE THE PAYMENT CHANNELS THAT FLEXPAY**  
9 **PARTICIPANTS MAY UTILIZE.**

10 A. FlexPay participants can utilize several authorized payment channels, including immediate  
11 payments made via telephone, the Kentucky Power website, the Company's app or an  
12 authorized in-person payment location. Accepted methods of payment include electronic  
13 checks, debit or credit cards, as well as cash payments at any of the 30 authorized in-person  
14 payment locations.

15 **Q. WILL FLEXPAY CUSTOMERS HAVE ACCESS TO FINANCIAL ASSISTANCE**  
16 **PROGRAMS?**

17 A. Yes. FlexPay customers will have the same access to energy assistance as those on  
18 post-pay billing. Kentucky Power will apply all received payments to the customer's  
19 account including payments from the Low Income Home Energy Assistance Program  
20 ("LIHEAP") or social agencies. However, any FlexPay customer seeking Winter Hardship  
21 Reconnection, a Certificate of Need, or a Medical Certificate under 807 KAR 5:006,  
22 Sections 14, 15, and 16 will be removed from FlexPay and reverted to the standard

1 post-pay service. This reversion is required because FlexPay does not allow credit  
2 extensions and requires a positive account balance for reconnection.

3 **Q. PLEASE DESCRIBE HOW KENTUCKY POWER WILL MARKET TO AND**  
4 **EDUCATE ITS CUSTOMERS ABOUT THE FLEXPAY PROGRAM.**

5 A. Kentucky Power's communications plan will include several means of outreach to its  
6 customers including printed materials, e-mail, social media, and information on Kentucky  
7 Power's website. The communications plan will include clear and concise information  
8 designed to manage customer expectations and ensure that customers fully understand  
9 FlexPay prior to enrollment. Exhibit SNC-3 contains draft samples of FlexPay customer  
10 communications.

11 The education efforts will continue beyond the initial outreach for enrollment.  
12 When a customer initially enrolls in the program, they will begin receiving alert  
13 notifications via e-mail, text messaging, or both depending on their chosen communication  
14 method. Customers will know immediately that they are enrolled in the program by  
15 receiving a "Welcome to FlexPay" alert message. After receiving the initial alert message,  
16 alerts are triggered by customer activity such as payments received, daily balance  
17 information, and notifications from Kentucky Power such as a change from on-peak to  
18 off-peak pricing for those customers enrolled in a time-of-day tariff. FlexPay customers  
19 have the potential to receive up to 18 different alerts that will continue throughout a  
20 customer's participation in the program. Energy savings information and tools will also be  
21 available 24/7 on the customer engagement platform accessible on the Company's website.

1 Prior to the implementation of FlexPay, Kentucky Power employees will receive  
2 specific training related to FlexPay to better support both interested customers and ongoing  
3 participants.

4 **Q. WHAT INFORMATION IS THE COMPANY PROPOSING TO PROVIDE**  
5 **CUSTOMERS IN CONNECTION WITH FLEXPAY?**

6 A. Exhibit SNC-4 includes a draft of the proposed FlexPay customer statement (bill), which  
7 will be issued monthly to customers. This statement contains the same information that  
8 customers can access online. The proposed FlexPay customer statement will provide nearly  
9 all relevant billing information as required by 807 KAR 5:006, Section 7. However, due to  
10 the nature of the FlexPay program, certain information such as meter readings and  
11 consumption data will be available to customers and reflected on their bill daily instead of  
12 monthly. This daily access allows FlexPay customers to utilize detailed information to  
13 better manage their usage and electricity expenses.

14 The proposed FlexPay customer statement will not feature specific line items for  
15 taxes and adjustments, as outlined in 807 KAR 5:006, Section 7(1)(a)(8)–(9). Including  
16 these as separate daily line items may complicate the billing information since those  
17 amounts are already incorporated into the customer's daily FlexPay amount and balance.  
18 Additionally, the meter constant, the total bill amount, and the date after which a penalty  
19 may apply, as specified in 807 KAR 5:006, Sections 7(1)(a)(6), (10), and (11), respectively,  
20 will not be part of the FlexPay customer statement, as this information is not applicable to  
21 the FlexPay program. As such, the proposed FlexPay bill format is suitable given the  
22 potential for multiple payment transactions throughout the month and the daily account  
23 balance calculation.

As described earlier, the Company will also offer various channels through which customers enrolled in the FlexPay program can communicate with the Company and obtain information about the program, their account balance and minimum balance, as well as their energy usage and costs.

**Q. ARE THERE COSTS ASSOCIATED WITH THE FLEXPAY PROGRAM?**

A. Yes. The estimated one-time capital cost for implementing the FlexPay program is approximately \$75,000. This amount includes expenses for software and programming modifications required to enable the Company's billing system to support FlexPay. Company Witness Wolfram further discusses the Company's request for deferral related to these costs.

**Q. ARE ANY WAIVERS REQUIRED TO IMPLEMENT THE FLEXPAY PROGRAM?**

A. Yes. The Company is requesting a waiver from the following requirements:

- **807 KAR 5:006, Section 15(1)(f) Refusal or Termination of Service.** This regulation requires a utility to mail or otherwise deliver an advance termination notice. The electronic notification features of the FlexPay program provide customers with frequent and timely updates regarding their balances and disconnection warnings. This approach offers more notifications about potential service termination compared to traditional forms of notice outlined in the regulation.
- **807 KAR 5:006, Section 7 Billings, Meter Readings, and Information.** This regulation specifies the information that must be included on a customer's monthly bill. The existing bill format does not accommodate a transactional overview of a

FlexPay participant's monthly activities, which may involve multiple transactions.

Kentucky Power proposes to offer FlexPay customers a revised statement that reflects daily transactions.

**Q. HAS THE COMMISSION APPROVED PREPAY PROGRAMS FOR OTHER KENTUCKY ELECTRIC UTILITIES?**

A. Yes. The Commission approved prepay proposals along with deviations to 807 KAR 5:006, Section 15(1)(f) and 807 KAR 5:006, Section 7 for numerous electric utilities within the Commonwealth. Figure SNC-3 provides the utility name, case number, and date of approval for similar requests.

<b>Figure SNC-3</b>			
<b>Utility Name</b>	<b>Case Number</b>	<b>Deviation from 807 KAR 5:006, Section 15(1)(f)(1) and Section 7</b>	<b>Approved by Order Dated</b>
Big Sandy RECC	2015-00337	Approved	4/7/2016
Blue Grass Energy Co-op	2012-00260	Approved	8/10/2012
Clark Energy Co-op	2019-00011	Approved	7/10/2019
Cumberland Valley	2014-00139	Approved	8/26/2014
Farmers RECC	2012-00437	Approved	1/23/2013
Fleming-Mason	2014-00411	Approved	4/15/2015
Grayson RECC	2012-00426	Approved	7/31/2013
Inter-County Energy	2015-00311	Approved	3/17/2016
Jackson Energy Co-op	2010-00210	Approved	11/30/2010
Kenergy	2017-00161	Approved	8/31/2017
Licking Valley RECC	2014-00256	Approved	10/1/2014
Nolin RECC	2011-00141	Approved	6/20/2011
Owen Electric Co-op	2013-00403	Approved	2/7/2014
Salt River Electric	2012-00141	Approved	7/11/2012
Shelby Energy Co-op	2013-00129	Approved	7/9/2013
South Kentucky RECC	2013-00198	Approved	11/15/2013
Taylor County RECC	2020-00278	Approved	12/22/2020

**V. HOME ENERGY ASSISTANCE**

**Q. DOES KENTUCKY POWER PROVIDE CUSTOMER BENEFITS THROUGH A HOME ENERGY ASSISTANCE PROGRAM?**

A. Yes. Kentucky Power offers two HEA programs: the Home Energy Assistance in Reduced Temperatures (“HEART”) and the Temporary Heating Assistance in Winter (“THAW”) programs.

**Q. PLEASE DESCRIBE THE HEART AND THAW PROGRAMS.**

A. The HEART program 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 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 CAK and the local community action agencies. Kentucky Power, CAK, and the community action agencies 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.

**Q. HOW ARE THE HEART AND THAW PROGRAMS FUNDED?**

A. The Residential Energy Assistance Tariff (“Tariff R.E.A.”) collects a monthly \$0.40 per meter surcharge from residential customers. The HEA programs are funded through a combination of Tariff R.E.A. and a two-for-one 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-4, for the 2024-2025 program year, there was \$1,716,761 available for HEART and \$572,254 available for THAW to distribute to eligible participants. This amount of funding supported a total of 3,172 electric heating customers and 1,110 non-electric heating customers through the HEART program. As the THAW program supports a maximum of \$175 per customer, this level of funding supported a minimum of 3,270 customers. Accordingly, the HEART and THAW programs supported a total of at least 7,552 customers.

**Figure SNC-4**  
**Current Funding for 2024-2025 Program Year**

	<b>HEART (75%)</b>		<b>THAW (25%)</b>	<b>Total</b>
<b>Total REA Funds Available (Post 10% Admin Cap)</b>	\$1,716,761		\$572,254	
<b>Funds Broken Out By</b>	Electric Heat (85%)	Non- Electric Heat (15%)	N/A	
<b>Funding</b>	\$1,459,247	\$257,514	\$572,254	<b>\$2,289,015</b>
<b>Payment Amount</b>	\$115	\$58	\$175	
<b>Total Available Benefit Per Customer</b>	\$460	\$232	\$175	
<b>No. of Customers Able to Receive Benefit</b>	3,172	1,110	3,270	<b>7,552</b>

**Q. IS THE COMPANY PROPOSING TO CHANGE THE LEVEL OF HEA FUNDING IN THIS CASE?**

**A.** No. The Company is proposing to maintain the HEA funding from Tariff R.E.A. (Residential Energy Assistance) at its current level which is \$0.40 per residential meter per month and a Company match at two-to-one or \$0.80 per residential meter per month. Maintaining the current funding level allows the HEART and THAW programs to deliver essential wintertime assistance to customers in need, while the Company assesses customer participation and overall demand. Additionally, in light of the uncertainties surrounding federal funding for LIHEAP for fiscal year 2026, it is imperative to ensure the continued funding of the HEART and THAW programs to provide assistance to customers in need.

**VI. ECONOMIC DEVELOPMENT AND KENTUCKY POWER**  
**ECONOMIC GROWTH GRANT (K-PEGG) PROGRAM**

1   **Q.   DOES KENTUCKY POWER PARTICIPATE IN ECONOMIC DEVELOPMENT?**

2   A.   Yes. Kentucky Power actively participates in economic development. As discussed by  
3       Company Witness Wiseman, fostering economic growth and business retention are  
4       important priorities for both the Company and its customers. In response to ongoing decline  
5       in load and customer count, Kentucky Power plays a vital role in economic development  
6       for eastern Kentucky by working to maintain existing businesses while also enhancing the  
7       region's economy to attract new customers and increase load.

8   **Q.   DOES THE COMPANY HAVE A PROGRAM FOCUSED ON ECONOMIC**  
9       **DEVELOPMENT?**

10  A.   Yes. Kentucky Power has been funding and administering the K-PEGG program since  
11       2015. This program provides grant funding specifically targeted at projects that enhance  
12       the economic development potential of communities within the Company's service  
13       territory. The Commission initially approved Tariff K.E.D.S. in Case No. 2014-00396,  
14       which finances the K-PEGG program. In approving the Company's Tariff K.E.D.S., the  
15       Commission recognized the crucial role that the Company plays in regional economic  
16       development. The K-PEGG program is supported by Tariff K.E.D.S. at a rate of \$1.00 per  
17       non-residential meter per month with the Company providing a matching contribution  
18       dollar-for-dollar.

19  **Q.   IS THE COMPANY PROPOSING ANY CHANGES TO TARIFF K.E.D.S. OR THE**  
20       **K-PEGG PROGRAM?**

21  A.   No. The continuation of the K-PEGG program directly addresses critical economic  
22       development challenges in the region. Kentucky Power proposes to continue the K-PEGG

1 program and maintain Tariff K.E.D.S. funding at \$1.00 per meter per month for  
2 non-residential customers, with the Company providing a dollar-for-dollar match in  
3 contributions.

## **VII. TARIFF SHEET CHANGES**

4 **Q. PLEASE DESCRIBE THE INFORMATION PROVIDED IN SECTION II,**  
5 **EXHIBITS D AND E TO THE APPLICATION.**

6 A. Section II, Exhibit D to the Application in this proceeding provides the annotated version,  
7 and Section II, Exhibit E to the Application the redlined version, of the Company's  
8 proposed tariff sheets in accordance with 807 KAR 5:011. These Exhibits to the  
9 Application are required by 807 KAR 5:001, Section 16(1)(b)(3) and Section 16(1)(b)(4),  
10 respectively and I am the witness sponsoring both Exhibits.

11 **Q. PLEASE DESCRIBE THE TARIFF SHEET CHANGES THE COMPANY IS**  
12 **PROPOSING IN THIS CASE.**

13 A. The Company is proposing to add two new tariffs and modify certain existing tariff sheets.  
14 Figure SNC-5 provides an overview of these proposals. Additionally, the Company has  
15 tariff change proposals in TFS 2025-00365 (Annual Update for Tariff System Sales  
16 Clause), TFS 2025-00366 (Annual Update for Tariff Decommissioning Rider), and TFS  
17 2025-00367 (Annual Update for Tariff Purchase Power Adjustment), which are currently  
18 pending. To the extent those proposals and any subsequent tariff filings are approved, the  
19 Company will incorporate the changes into the compliance filing following an order in this  
20 proceeding.

**Figure SNC-5  
Tariff Change Proposals**

<b>Tariff</b>	<b>Status</b>	<b>Proposal</b>	<b>Supported By Company Witness(es)</b>
FlexPay (F.P.)	New	New tariff offering prepayment option for residential customers	Cobern
Generation Rider (G.R.)	New	New rider to recover the non-environmental capital investment in Mitchell Plant	Wolffram
Cogeneration and/or Small Power Production -- 100 KW or Less (COGEN/SPP I) and Cogeneration and/or Small Power Production -- Over 100 KW (COGEN/SPP II)	Existing	Consolidate tariffs	Cobern
Environmental Surcharge (E.S.)	Existing	Updated tariff language to reflect new base period revenue requirement and return on equity	Cullop
Federal Tax Cut (F.T.C.)	Existing	Allow recovery of net operating loss carryforward regulatory asset pending a private letter ruling from the IRS	Wolffram; Hodgson
Net Metering Service II (N.M.S. II)	Existing	Updated tariff language to incorporate KRS 278.466(4) language	Cobern
Purchase Power Agreement (P.P.A.)	Existing	Change to allow recovery or provide credit	Wolffram; Stutler

Tariff	Status	Proposal	Supported By Company Witness(es)
		for any incidental gains or losses on the sale of gas	
Residential Service (R.S.)	Existing	Tiered residential customer charge and block energy rates	Wolffram; Spaeth
Terms and Conditions (T&C's) section 19	Existing	Update rates for miscellaneous service charges	Wolffram
Voluntary Curtailment Service (V.C.S.)	Existing	Eliminate tariff	Cobern

**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 and formatting changes to its current tariffs. My Direct 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. In addition to the new FlexPay Tariff I discussed previously, I also support changes to the Tariffs COGEN/SPP I and II, Net Metering Service II Tariff, and the Voluntary Curtailment Service Tariff. I also support the addition of supplemental language in the Company's Terms and Conditions that addresses the necessity of removing an account from the Equal Payment Plan, and the AMP plan, upon enrollment in the FlexPay program.

**COGEN/SPP I and II**

1 **Q. IS THE COMPANY PROPOSING ANY MODIFICATIONS TO ITS TARIFFS**  
2 **COGEN/SPP I AND II?**

3 A. Yes. The Company proposes to consolidate Tariff COGEN/SPP I and COGEN/SPP II into  
4 a single tariff. The existing language in both tariffs is largely identical, with the exception  
5 of the maximum capacity and definition of demand metering requirement. The Company  
6 aims to streamline these tariffs by providing one COGEN/SPP tariff to improve clarity and  
7 consistency in its offerings.

8 The Company also seeks to provide a clearer delineation of contract terms for  
9 customers requesting service under Tariff COGEN/SPP. Currently the tariff stipulates a  
10 minimum duration of five years. The Company proposes to establish that the maximum  
11 contract shall not exceed 20 years.

12 In addition to the modifications described above, Kentucky Power also proposes to  
13 add to Tariff COGEN/SPP specific criteria to define what constitutes a legally enforceable  
14 obligation (“LEO”). LEOs are a foundational part of the Public Utility Regulatory Policies  
15 Act (“PURPA”). A LEO must be established before the interconnecting utility has an  
16 obligation to enter into a contract to purchase the output from a Qualifying Facility (“QF”)  
17 at avoided cost rates. In its 2020 revisions to the PURPA regulations for QFs, FERC’s final  
18 rule required that QFs must demonstrate commercial viability and financial commitment  
19 to build under objective and reasonable state-determined criteria. Essentially, these criteria  
20 are intended to ensure that a prospective Tariff COGEN/SPP customer is commercially  
21 viable, financially committed, and sufficiently advanced in its development before the  
22 Company commits resources to it.

**Net Metering Service II**

1   **Q.    IS THE COMPANY PROPOSING ANY MODIFICATIONS TO ITS TARIFF**  
2       **N.M.S. II?**

3    A.    Yes. The Company is proposing to enhance the language in its Tariff N.M.S. II (Net  
4        Metering Service II) to confirm that credits provided under KRS 278.466(4) are not  
5        transferrable and that unused credits expire when a customer no longer takes service under  
6        Tariff N.M.S. II.

**Voluntary Curtailment Service**

7   **Q.    IS THE COMPANY PROPOSING ANY MODIFICATIONS TO ITS VOLUNTARY**  
8       **CURTAILMENT SERVICE TARIFF?**

9    A.    Yes. The Company is proposing to eliminate its Tariff Voluntary Curtailment Service  
10       ("V.C.S.") due to insufficient customer interest. Since its inception, there have been no  
11       requests for service under Tariff V.C.S. Instead, customers seeking a curtailment program  
12       have chosen to participate under Tariff Contract Service-Interruptible Power, which will  
13       continue to be available.

**VIII.   CONCLUSION**

14   **Q.    DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

15   A.    Yes, it does.



## VERIFICATION

The undersigned, Stevi N. Cobern, being duly sworn, deposes and says she is a Regulatory Consultant Principle 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 )  
 )  
County of Boyd )

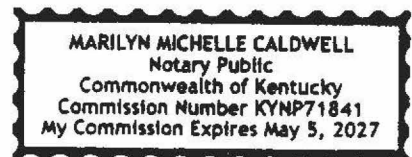
Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Stevi N. Cobern, on August 12, 2025.

Marilyn Michelle Caldwell  
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841



## **Tariff F.P. (FlexPay Program)**

DN

### **Availability of Service**

This tariff is available on a voluntary basis to all residential customers who have an Advanced Metering Infrastructure (AMI) meter installed at their residence, except as provided below.

This tariff is not available to residential customers taking metered service under Tariff R.S.D. or customers with medical, life threatening, or life support conditions; customers having on-site generation operated in parallel with the Company's system; or customers on the Average Monthly Payment (AMP) plan or Equal Payment Plan (Budget). It also is not available to customers without a valid and operable electronic communication method (i.e., text or electric mail). It also is not available to a customer scheduled for a disconnection of service for nonpayment who has initiated the process for enrollment in this tariff two or more times within a thirty (30) day period without completing all of the requirements for enrollment.

### **Program Description**

Kentucky Power's FlexPay Program is a voluntary payment option that allows customers to prepay for, and pay as they use, electric service.

### **Terms and Conditions**

1. Service under FlexPay will be offered to a customer under the customer's otherwise applicable standard residential rate schedule. Billing will be based on the customer's daily usage, the effective base rate, the tax rate, and all applicable riders and fees. Fixed charges will be applied to the account on a daily basis based on 1/30 of the total fixed charges. These amounts will be subtracted from the customer's daily FlexPay account balance.
2. To enroll in FlexPay, a customer must make an initial payment of \$40.00. Any deposit that an existing customer has previously paid to the Company will be applied to the customer's current account balance, with the remaining credit/debit balance transferred to the customer's prepay balance. A customer with an outstanding current balance or final account balance from a previous account may carry-over up to \$500 of the account balance to the FlexPay Program. Any payments made to the account will first have a 20% portion of the payment applied to the arrears balance before it is credited to the customer's account until the past due balance is paid.
3. The customer is responsible for monitoring prepaid usage and ensuring that the account balance is sufficient to continue electric service. The customer will be notified when the account reaches the customer-selected balance threshold or the minimum threshold amount of \$25.00. Notification will occur through the customer's preferred form of communication, including email, and/or text message. A customer web portal will be available to view the customer's usage information.
4. Should a customer's balance reach zero, the customer will be notified via the customer's chosen communication method. The customer will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours. Normal business hours are 8:00 a.m. to 5:00 p.m., Monday through Thursday, and 8:00 a.m. to noon on Fridays, excluding Company-observed holidays and moratoriums. Customers will be required to adjust their payment to cover any accrued balance for usage during weekends, holidays and moratoriums. Once the customer's payment is received and accepted, service will be restored by the Company in a timely manner.

*Continued on Sheet 24-2*

DATE OF ISSUE: August 29, 2025  
DATE EFFECTIVE: Services Rendered On And After March 1, 2026  
ISSUED BY: /s/ Tanner S. Wolfram  
TITLE: Director, Regulatory Services  
By Authority of an Order of the Public Service Commission  
In Case No.: 2025-00257 Dated XXXX XX, XXXX

**Tariff F.P.  
(FlexPay Program)**

DN

**Terms and Conditions Continued**

5. Financial assistance received for a FlexPay account will be credited to the balance of the FlexPay account upon receipt of the funds.
6. Customers presenting a Winter Hardship Reconnect, Certificate of Need, or Medical Certificate as provided in 807 KAR 5:006, Sections 14, 15, and 16 will be removed from FlexPay and placed on the tariff that is otherwise applicable to the customer's service.
7. No deposit, reconnect, or late fee charges shall apply to customers enrolled in FlexPay.
8. When the Company receives a dishonored negotiable instrument (i.e. returned check), any account credits associated with that instrument will be removed from the customer's account. If the removal of the credits results in the customer's balance reaching zero, the customer will be notified and will have until the beginning of the next business day to reestablish a positive balance or the customer's meter will automatically be disconnected during normal business hours.
9. Actual billing will continue to be based upon the applicable rate and meter readings obtained to determine consumption. FlexPay customers are required to participate in and receive their information through the Company's paperless billing program. Customers will continue to receive an online monthly statement summary containing all of the charges, usage, and payments applied during their normal 30-day billing cycle.
10. Customer accounts must be funded through a Company authorized payment channel, including immediate payment via telephone or website using electronic check, debit or credit cards, and any in-person pay station. Each authorized payment method is subject to Company guidelines. Timing of the payments to the accounts cannot be guaranteed if payment is made through an unauthorized pay agent or by mail.
11. The customer may cancel service under this tariff at any time and will be returned to the applicable traditional post-pay billing option in accordance with Kentucky Power's Commission approved tariffs.
12. Settlement occurs when participation in the plan is terminated. This happens if an account is final billed or if the customer requests termination. If the account finals off-cycle during the billing period, the remaining monthly fixed charges and fees that have not been collected will be applied to the final bill. After settlement of the FlexPay account, any remaining unused balance will be transferred to the customer's other active account(s). If the customer does not have any other active accounts the Company shall refund by one of the following means: a prepaid card, a check, or electric funds transfer (EFT).

DATE OF ISSUE: August 29, 2025  
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Proposed Customer Charge Tier 1	\$26
Proposed Customer Charge Tier 2	\$40

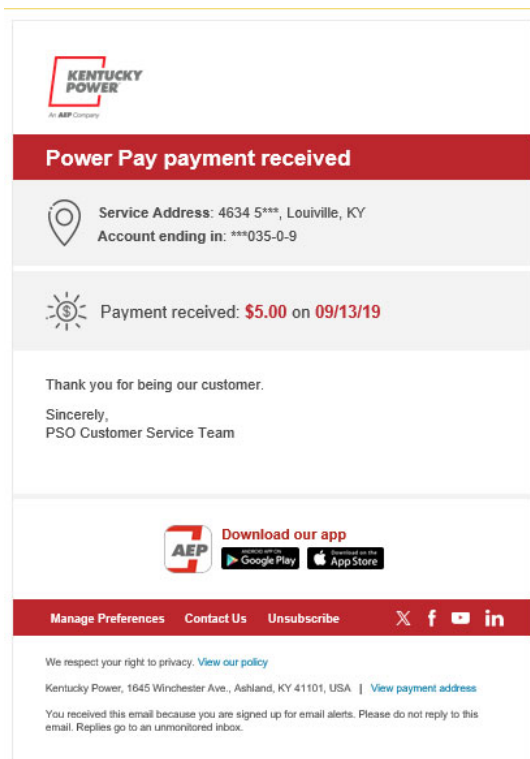
Customer 1: Does Not Exceed 2,000 kWh				Customer 2: Exceeds 2,000 kWh			
	Daily Usage	Monthly Usage	Customer Charge	Daily Usage	Monthly Usage	Customer Charge	
Day 1	45	45	\$0.87	90	90	\$0.87	
Day 2	45	90	\$0.87	90	180	\$0.87	
Day 3	45	135	\$0.87	90	270	\$0.87	
Day 4	45	180	\$0.87	90	360	\$0.87	
Day 5	45	225	\$0.87	90	450	\$0.87	
Day 6	45	270	\$0.87	90	540	\$0.87	
Day 7	45	315	\$0.87	90	630	\$0.87	
Day 8	45	360	\$0.87	90	720	\$0.87	
Day 9	45	405	\$0.87	90	810	\$0.87	
Day 10	45	450	\$0.87	90	900	\$0.87	
Day 11	45	495	\$0.87	90	990	\$0.87	
Day 12	45	540	\$0.87	90	1080	\$0.87	
Day 13	45	585	\$0.87	90	1170	\$0.87	
Day 14	45	630	\$0.87	90	1260	\$0.87	
Day 15	45	675	\$0.87	90	1350	\$0.87	
Day 16	45	720	\$0.87	90	1440	\$0.87	
Day 17	45	765	\$0.87	90	1530	\$0.87	
Day 18	45	810	\$0.87	90	1620	\$0.87	
Day 19	45	855	\$0.87	90	1710	\$0.87	
Day 20	45	900	\$0.87	90	1800	\$0.87	
Day 21	45	945	\$0.87	90	1890	\$0.87	
Day 22	45	990	\$0.87	90	1980	\$0.87	
Day 23	45	1035	\$0.87	90	2070	\$0.87	
Day 24	45	1080	\$0.87	90	2160	\$14.87	
Day 25	45	1125	\$0.87	90	2250	\$0.87	
Day 26	45	1170	\$0.87	90	2340	\$0.87	
Day 27	45	1215	\$0.87	90	2430	\$0.87	
Day 28	45	1260	\$0.87	90	2520	\$0.87	
Day 29	45	1305	\$0.87	90	2610	\$0.87	
Day 30	45	1350	\$0.87	90	2700	\$0.87	
			\$26				\$40

## FlexPay Program Customer Communication Examples

### Available Text and E-mail Alert Messages:

Pre-enrollment Summary	Daily Balance	Moratorium
Pre-enrollment Payment	Low Balance	Payment Returned Pending
FlexPay Account Pending	Zero Balance	Payment Returned
Welcome Message	Customer Charge Threshold	Balance Transferred
Payment Received	Statement Available	Balance Adjustment
Enrollment Failed	Seasonal Rate Change	Unenrolled from Flex Pay

### Email Alert Example



### Text Alert Example

KY Pwr has received your payment of \$5.00 for your account ending in 42870 at 4000 B\*\*\*. Visit: <http://kypco.com/account>.



Non-Payment/Return Mail:  
PO BOX 24401  
CANTON, OH 44701-4401

Flex Pay Balance as of  
June 17, 2025 **-\$XX.XX**  
Your statement date is Jun 17, 2025  
Account #XXX-XXX-XXX-X-X

CY13

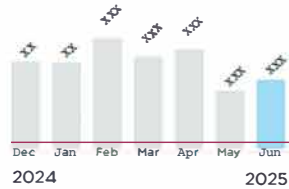


KY PREPAY CUST  
4676 N MAIN ST  
ANYWHERE, KY  
74126-3154

#### Notes from KYPO:

Your current Flex Pay balance is **-\$XX.XX**. Last statement balance was **-\$XX.XX**, and the amount used this month was **\$XX.XX**. Your total energy usage was **XXX kWh**.

#### Usage History (kWh):



#### Current statement summary:

Service from 05/18/25 - 06/17/ 25 (31 days)	
Power Pay payments	\$X.XX
Power Pay balance	-\$XX.XX
Carryover amount remaining	-\$XXX.XX
\$0.00 has been applied to your carryover balance.	

#### Methods of Payment

kentuckypower.com  
 PO Box 371496  
Pittsburgh, PA 15250-7496  
 1-800-611-0964 (fee may apply)

#### Need to get in touch?

Customer Operations Center: 1-800-572-1113  
Outages: [kentuckypower.com/outages](http://kentuckypower.com/outages)  
or 1-800-572-1113

Please tear on dotted line.

Turn over for important information!



**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 Certain Regulatory And Accounting )  
Treatments; and (4) All Other Required Approvals )  
And Relief )

Case No. 2025-00257

**DIRECT TESTIMONY OF**

**JOHN D. CULLOP**

**ON BEHALF OF KENTUCKY POWER COMPANY**



**DIRECT TESTIMONY OF  
JOHN D. CULLOP ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT JDC-1	Nov. 18, 2024 - Environmental Surcharge Cover Letter
EXHIBIT JDC-2	Adjusted Environmental Base
EXHIBIT JDC-3	Proposed Environmental Surcharge Tariff
EXHIBIT JDC-4	Revised Monthly Environmental Surcharge Forms
EXHIBIT JDC-5	Reporting Detail for FERC 930 Accounts
EXHIBIT JDC-6	Invoices Greater than \$250

**DIRECT TESTIMONY OF  
JOHN D. CULLOP ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is J.D. Cullop. My position is Regulatory Consultant Senior for Kentucky Power  
3       Company (“Kentucky Power” or the “Company”). My business address is 1645  
4       Winchester Avenue, Ashland, Kentucky 41101.

**II. BACKGROUND**

5   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
6       **BUSINESS EXPERIENCES.**

7   A.   I received a Bachelor of Business Administration degree from Morehead State University  
8       in Morehead, Kentucky in 2016. From 2017 through 2022 I worked at Lithko Contracting,  
9       LLC, a concrete contracting company based out of West Chester, Ohio, as a tax and  
10      accounting analyst. I then worked in a corporate accounting and analyst position with Big  
11      Sandy Distribution, Inc., until I accepted my current position with Kentucky Power in  
12      August 2024.

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

15   A.   I am responsible for supporting Kentucky Power’s regulatory activities, including  
16      preparing the monthly fuel adjustment clause (“FAC”) filings and Environmental

1 Surcharge Tariff (“Tariff E.S.”) filings, and assisting with the Company’s other periodic  
2 regulatory filings.

### III. PURPOSE OF TESTIMONY

3 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
4 **PROCEEDING?**

5 A. The purpose of my Direct Testimony is to support an update to the Company’s base  
6 revenue requirement for its environmental surcharge. Additionally, I support the following  
7 adjustments to the Company’s test year capitalization, rate base, revenue, and operating  
8 expenses:

- 9 • Remove Mitchell flue gas desulfurization (“FGD”) Operating and Maintenance  
10 expenses (W19);
- 11 • Remove the capital cost of Mitchell FGD and Consumable Inventory from rate  
12 base (W57);
- 13 • Remove Mitchell FGD-related revenues from test year (W08);
- 14 • Remove fuel adjustment clause revenues and synchronize fuel revenues and  
15 expenses (W09);
- 16 • Rate case expense adjustment (W23);
- 17 • Elimination of miscellaneous business and advertising expenses (W24); and
- 18 • Elimination of non-recoverable business expenses (W36).

19 Finally, I support the inclusion of the Company’s Edison Electric Institute (“EEI”)  
20 membership fees and other miscellaneous business expense costs in the test year cost-of-  
21 service. I provided the adjustments to revenues, operating expenses, and rate base to  
22 Company Witness Cost for inclusion in the computation of the Company’s jurisdictional

1 revenue requirement. I provided the adjustments to capitalization to Company Witness  
2 Cost to present in Section V, Schedule 3.

3 **Q. ARE YOU SPONSORING ANY EXHIBITS?**

4 A. Yes. I am sponsoring the following exhibits:

- 5 • Exhibit JDC-1 – November 18, 2024 - Environmental Surcharge Cover Letter
- 6 • Exhibit JDC-2 – Adjusted Environmental Base
- 7 • Exhibit JDC-3 – Proposed Environmental Surcharge Tariff
- 8 • Exhibit JDC-4 – Revised Monthly Environmental Surcharge Forms
- 9 • Exhibit JDC-5 – Reporting Detail for FERC 930 Accounts
- 10 • Exhibit JDC-6 – Invoices Greater than \$250

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

13 A. Yes.

**IV. BASE ENVIRONMENTAL REVENUE REQUIREMENT**

14 **Q. PLEASE EXPLAIN HOW KENTUCKY POWER RECOVERS ITS**  
15 **ENVIRONMENTAL COMPLIANCE COSTS.**

16 A. Kentucky Power recovers the costs of authorized environmental projects included in its  
17 Environmental Compliance Plan (“ECP”) through a combination of base rates and Tariff  
18 E.S. The Company’s current ECP was approved in Case No. 2023-00159 and includes  
19 projects necessary for the Company to comply with the Federal Clean Air Act and federal,  
20 state, and local requirements applicable to coal combustion wastes and by-products of  
21 coal-fired generation facilities. Each month, the Company calculates the costs associated  
22 with the approved environmental projects included in its ECP. These total monthly costs

1 include expenses and credits related to the operation of approved projects, a return on the  
2 environmental rate base including construction work in progress (“CWIP”), a return on the  
3 Company’s emission allowance inventory, costs associated with the consumption of  
4 consumables, depreciation, asset retirement obligation (“ARO”) depreciation and accretion  
5 expenses, and associated property taxes for the Mitchell Plant. The Company then  
6 compares the total monthly environmental costs to the amount of environmental costs  
7 included in its base rates. If the total monthly environmental costs exceed the monthly base  
8 rate amount, customers are charged the difference through the environmental surcharge. If  
9 the total monthly environmental costs are less than the monthly base rate amount,  
10 customers are credited the difference through the environmental surcharge.

11 **Q. WERE THERE ANY CHANGES DURING THE TEST YEAR TO ITEMS**  
12 **INCLUDED WITHIN THE MONTHLY TOTAL ENVIRONMENTAL COSTS?**

13 A. Yes, there were two changes. First, the Company placed in-service the wastewater ponds  
14 required to comply with the Coal Combustion Residuals (“CCR”) rule in October 2024.  
15 The Public Service Commission of Kentucky (the “Commission”) approved the CCR  
16 project as part of the Company’s 2021 ECP in Case No. 2021-00004, including a return on  
17 CWIP until the project was placed in service.

18 Second, in the third quarter of 2024, Kentucky Power began recognizing ARO  
19 accretion expense and ARO depreciation expense related to the incremental ARO  
20 associated with the Federal EPA’s Revised CCR Rule. Based on the Commission’s May  
21 2, 2022 Order in Case No. 2021-00004, costs associated with Mitchell Plant, specifically  
22 costs of CCR compliance, are recoverable through the Company’s environmental  
23 surcharge.

Both the CCR wastewater ponds and ARO accretion and depreciation expense are discussed further in the Company's November 18, 2024 cover letter to its monthly environmental surcharge filing which is attached as Exhibit JDC-1.

**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 environmental projects in each month of the test year. These Non-FGD costs included an annualized monthly amount of ARO depreciation and accretion expense. This was done by removing the actual monthly ARO depreciation and accretion expenses included in the test year, and then inserting the annualized monthly expense amount for each month of the test year. The base revenue requirement next included gains on allowances in each month. Lastly, the Company removed: (a) the return on CWIP for CCR during the test year because the CCR project was placed in service in October 2024; and (b) costs associated with the Mitchell FGD during the test year (discussed below). Exhibit JDC-2 provides the monthly environmental base rate amounts.

**Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE DEPRECIATION RATES USED TO CALCULATE DEPRECIATION EXPENSE FOR ENVIRONMENTAL EQUIPMENT AT THE MITCHELL PLANT?**

A. No. The Company uses a 2.96% depreciation rate for the projects at the Mitchell Plant included in the environmental compliance plan, as approved by the Commission in Case No. 2017-00179. However, the CCR project approved in Case No. 2021-00004 has a

1 separate depreciation rate of 20%. Mitchell Plant depreciation rates are discussed further  
2 in the Direct Testimony of Company Witness Wolfram.

3 **Q. WHAT WEIGHTED AVERAGE COST OF CAPITAL (“WACC”) WAS USED IN**  
4 **CALCULATING THE REVENUE REQUIREMENT FOR ENVIRONMENTAL**  
5 **PROJECTS?**

6 A. Kentucky Power used a 9.14% pre-tax WACC. In calculating the WACC for  
7 environmental projects, Kentucky Power used the 10.0% rate of return on equity (“ROE”)  
8 proposed by the Company in this case. The basis for using a 10.0% ROE is included in the  
9 Direct Testimonies of Company Witness Wiseman and Company Witness McKenzie.  
10 Additionally, Company Witness McKenzie discusses that the ROE should not be further  
11 reduced for single-issue recovery mechanisms such as the environmental surcharge.

12 **Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS GROSS REVENUE**  
13 **CONVERSION FACTOR (“GRCF”)?**

14 A. Yes. The revised GRCF can be found in Section V, Schedule 2, Page 2, of the Application.  
15 For the purpose of calculating the environmental surcharge base revenue requirement, the  
16 pre-tax debt GRCF of 1.004437 is used.

#### **V. CHANGES TO TARIFF E.S. AND THE ECP**

17 **Q. HAS THE COMPANY REVISED TARIFF E.S. TO REFLECT THE CHANGES TO**  
18 **THE WACC AND GRCF PROPOSED ABOVE?**

19 A. Yes. A copy of the Company’s proposed Tariff E.S., with markups indicating changes from  
20 the current Tariff E.S., is included as Exhibit JDC-3.

1   **Q.   HAS THE COMPANY ALSO REVISED THE ENVIRONMENTAL SURCHARGE**  
2       **FORMS USED FOR ITS MONTHLY FILING?**

3   A.   Yes. The Company is proposing two changes to the environmental surcharge forms. A  
4       copy of the Company's revised environmental surcharge forms is included as Exhibit  
5       JDC-4.

6           The first change is the removal of Line 42 (Monthly Installment of ELG Regulatory  
7       Asset Amortization) from Form 3.10. This regulatory asset was approved for recovery over  
8       two years through Tariff E.S. in the Commission's May 3, 2022, Order in Case  
9       No. 2021-00004. The Company amortized the final monthly installment of this regulatory  
10      asset in its April 2024 filing.

11          The second change is renaming Line 41 to "Monthly ARO Depreciation and  
12      Accretion Expense." This change is made to allow for ARO depreciation and accretion  
13      expenses for all approved environmental projects to be captured within the environmental  
14      surcharge.

15   **Q.   WAS THE COMPANY'S ECP ALSO UPDATED?**

16   A.   No. The Company is not proposing any projects be added or removed within this  
17      proceeding. However, the Company's currently pending application in Case  
18      No. 2025-00175 includes a request to amend its ECP to include costs associated with ELG  
19      compliance at the Mitchell Plant.



**VI. CAPITALIZATION, REVENUE, AND OPERATING EXPENSE ADJUSTMENTS****Mitchell FGD Adjustments**  
**(Section V, Exhibit 2, W08, W19, and W57)**

1    **Q.    WHAT IS THE COMPANY PROPOSING WITH REGARD TO MITCHELL FGD?**

2    A.    Consistent with paragraph 6 of the Commission-approved Settlement and Stipulation  
3           Agreement in Case No. 2012-00578, the Company is proposing to continue excluding  
4           Mitchell FGD costs from the base environmental revenue calculation and recovering those  
5           costs directly through the environmental surcharge.

6    **Q.    DID YOU PREPARE ANY ADJUSTMENTS TO REMOVE THE MITCHELL FGD**  
7           **FROM THE TEST YEAR RATE BASE AMOUNTS?**

8    A.    Yes. Adjustment W57 removes both the capitalization and the rate base amount of the  
9           Mitchell FGD from the test year. The rate base deduction was calculated by removing the  
10          accumulated depreciation and accumulated deferred income tax amounts from the FGD  
11          electric plant in service amount. The production demand allocation factor was then applied  
12          to the rate base amount. This results in a *reduction* of test year rate base amount of  
13          \$113,080,671.

14                This adjustment also removes the consumable inventory that is used in conjunction  
15                with the FGD. The production demand energy allocation factor was applied to the  
16                consumable inventory. This results in a *reduction* of test year base rate amount of  
17                \$1,025,060.

1 **Q. DID YOU PREPARE ANY ADJUSTMENTS TO REMOVE KENTUCKY**  
2 **POWER'S SHARE OF THE COSTS ASSOCIATED WITH THE MITCHELL FGD**  
3 **FROM THE TEST YEAR DATA?**

4 A. Yes. Adjustment W19 removes Mitchell FGD operating and maintenance expenses from  
5 the test year. The Mitchell FGD operating expense adjustment includes costs associated  
6 with gypsum disposal, limestone, lime hydrate, and polymer in addition to the depreciation,  
7 maintenance, and property tax expenses. This adjustment results in a *reduction* of test year  
8 expenses by a total of \$13,085,851.

9 **Q. DID YOU PREPARE ANY ADJUSTMENTS TO REMOVE KENTUCKY**  
10 **POWER'S REVENUES ASSOCIATED WITH THE MITCHELL FGD FROM THE**  
11 **TEST YEAR DATA?**

12 A. Yes. Adjustment W08 removes the revenues associated with Mitchell FGD from the cost-  
13 of-service. This adjustment is calculated by first determining the total test year revenues  
14 for the environmental surcharge, which is calculated by adding the total amount of  
15 environmental surcharge revenue for the test year to the test year annual environmental  
16 base revenue amount. The Company next deducted the going-forward annual  
17 environmental base revenue amount set forth in Exhibit JDC-2. This calculation results in  
18 a \$19,703,413 *reduction* to base rates that removes Mitchell FGD revenues and  
19 synchronizes the environmental compliance costs and revenues.

20 In addition to the removal of Mitchell FGD revenues, adjustment W08 also removes  
21 \$1,980,517 of deferred environmental surcharge revenue amounts. Removing revenue or  
22 expense related to over/under recovery ensures that rider-related revenue or expense  
23 amounts are not in the determination of the Company's base rates. Company Witness

1 Ciborek further discusses the basis for over/under recovery accounting in his Direct  
2 Testimony. The net result of the adjustment is a \$21,683,931 *reduction* to base revenues.

**Fuel Synchronization Adjustment**  
**(Section V, Exhibit 2, W09)**

3 **Q. PLEASE EXPLAIN THE ADJUSTMENT MADE TO THE TEST YEAR DATA TO**  
4 **REMOVE FUEL ADJUSTMENT CLAUSE REVENUES AND SYNCHRONIZE**  
5 **FUEL REVENUES AND FUEL EXPENSES.**

6 A. Fuel expense is a pass-through cost for the Company. This means that Kentucky Power  
7 does not earn a return on these costs, and customers only pay for the cost of the fuel.

8 There are three distinct items in the Company's cost-of-service related to fuel:

- 9 • Fuel Revenues – considers both base fuel and the fuel adjustment clause which  
10 recovers or credits anything above or below the base fuel amount;
- 11 • Fuel Expense; and
- 12 • Deferred Fuel Expense.

13 Adjustment W09 removes the test year FAC revenues and an equal amount of fuel  
14 expense from the cost-of-service. The adjustment then synchronizes the remaining level of  
15 base fuel revenue, fuel expense, and deferred fuel expense so that total fuel expense and  
16 fuel revenue is equal in the cost-of-service and does not impact base rate net income for  
17 purposes of calculating the revenue requirement increase. The resulting net impact of this  
18 adjustment is an *increase* in fuel expense of \$6,786,856.

1   **Q.   WERE THERE ANY CHANGES TO THE FUEL ADJUSTMENT CLAUSE**  
2       **WITHIN THE TEST YEAR THAT AFFECTED FUEL REVENUES OR**  
3       **EXPENSES?**

4   A.   Yes. Two items related to the Commission's December 13, 2024, Order in Case  
5       No. 2023-00008, and the Settlement Agreement approved therein, had a significant impact  
6       on fuel revenues and expenses during the test year.

7           In that Order, the Commission approved an increase in the base fuel rate from  
8       \$0.02612/kWh to \$0.0338/kWh. This rate change was effective for service rendered on and  
9       after December 31, 2024, and resulted in a prorated FAC rate for the expense month of  
10      January 2025.

11          Also, the Settlement Agreement approved within the Commission's Order in that  
12      case prospectively modified Kentucky Power's Peaking Unit Equivalent ("PUE")  
13      calculation and, in conjunction with that change, established a transitional monthly FAC  
14      credit to reduce the amount of future fuel costs recovered from Kentucky retail customers  
15      through the FAC. This credit was applied to customer's bills in the months of January 2025  
16      through May 2025 during the test year, reducing fuel revenues for the test year.

17          Finally, Kentucky Power's wholesale contracts with Olive Hill and Vanceburg  
18      expired at the end of May 2025. While this did not cause any changes during the test year,  
19      it did require an adjustment to the allocation factor used to calculate jurisdictional  
20      cost-of-service fuel cost as described in the Direct Testimony of Company Witness Cost.

1 **Q. WERE THESE CHANGES CONSIDERED WITHIN THE FUEL**  
2 **SYNCHRONIZATION ADJUSTMENT?**

3 A. Yes. Each of these changes are considered within the adjustment, with the exception of the  
4 going forward PUE calculation, which is addressed in Adjustment W45 presented in the  
5 Direct Testimony of Company Witness Wolfram.

**Rate Case Expense Adjustment**  
**(Section V, Exhibit 2, W23)**

6 **Q. WHAT IS THE RATE CASE EXPENSE ADJUSTMENT?**

7 A. The Company is permitted to recover its reasonable expenses for the preparation and  
8 litigation of this base rate case proceeding, including reasonable consulting and legal  
9 expenses. The Company estimates a base rate case expense, including the cost of a full  
10 notice to customers, of \$1,393,500 for this proceeding.

11 Adjustment W23, makes a pro forma adjustment to capture the previous base rate  
12 case expense regulatory asset approved for recovery in Case No. 2023-00159, as it was  
13 approved for recovery over a three-year period. Thus, there will still be an outstanding  
14 balance at the end of this proceeding. Based on the regulatory timeline and date of filing  
15 for this case, the expected balance of that regulatory asset on March 1, 2026, is estimated  
16 to be \$274,328. This expected balance was then added to the estimated costs in this case  
17 bringing the total estimated base rate case expense to \$1,667,828. Amortizing this amount  
18 over three years results in an annual average cost of \$555,943.

19 Finally, the Company removed \$314,004 of amortization related to the current base  
20 rate case expense regulatory asset.

21 The final result of this adjustment is an *increase* of \$241,939 to the Company's test  
22 year expenses.

**Non-Recoverable Business Expense Adjustment**  
**(Section V, Exhibit 2, W36)**

1    **Q.    PLEASE    EXPLAIN    THE    ADJUSTMENT    TO    ELIMINATE**  
2    **NON-RECOVERABLE BUSINESS EXPENSES.**

3    A.    The non-recoverable business expense adjustment removes expenses related to employee  
4    gifts and awards, social club memberships, and charitable contributions from the test year.  
5    Adjustment W36 *decreases* the Company's test year expenses by \$24,171.

**Miscellaneous Business Expense Adjustment**  
**(Section V, Exhibit 2, W24)**

6    **Q.    PLEASE    EXPLAIN    THE    ADJUSTMENT    TO    ELIMINATE    CERTAIN**  
7    **MISCELLANEOUS EXPENSES.**

8    A.    Adjustment W24 is made to remove certain test year business expenses that are not  
9    recoverable under 807 KAR 5:016, Section 4(1). The accounts reviewed for this adjustment  
10   are further detailed in the next section and include those related to political, promotional,  
11   and institutional advertising, corporate communications, general expenses, and associated  
12   business development. Following the review of the expenses recorded in these accounts, a  
13   total of \$54,804 was *removed* from test year operating expenses.

**VII. INCLUSION OF CERTAIN MISCELLANEOUS EXPENSES**  
**IN THE COST-OF-SERVICE**

14   **Q.    ARE YOU SUPPORTING ANY MISCELLANEOUS EXPENSES THAT ARE**  
15   **REASONABLE TO REMAIN IN THE COMPANY'S COST-OF-SERVICE?**

16   A.    Yes. I am supporting the recovery of certain expenses related to the Miscellaneous  
17   Business Expense Adjustment (W24), most notably the inclusion of certain expenses  
18   incurred from the EEI.

1   **Q.     WHAT IS THE EDISON ELECTRIC INSTITUTE?**

2   A.     Organized in 1933, the Edison Electric Institute is the association that represents all U.S.  
3           investor-owned electric companies. EEI members provide safe, reliable electricity for  
4           nearly 250 million Americans, and operate in all 50 states and the District of Columbia.  
5           The goal of EEI is to provide public policy leadership, strategic business intelligence, and  
6           essential conferences and forums to their member organizations. It also collects data and  
7           provides research, analysis, and expertise on a range of industry issues.

8   **Q.     PLEASE EXPLAIN WHY INCLUSION OF EEI EXPENSE IN THE COMPANY'S**  
9           **COST-OF-SERVICE IS APPROPRIATE.**

10  A.     EEI membership costs are essential for providing reliable electric service due to the direct  
11           benefits they offer to customers. Examples of the customer benefits provided by EEI  
12           membership include:

13       Mutual Assistance and Grid Resilience

14           Perhaps the most significant benefit to customers from the Company's membership is the  
15           work EEI does with its members on storm response and recovery. EEI and its member  
16           companies have devoted significant time and resources to enhance the reliability and  
17           resiliency of the energy grid, which directly benefits customers.

18           The work EEI has done with its members through the mutual assistance program  
19           has established and implemented an effective system whereby member companies may  
20           receive and provide assistance in the form of personnel and equipment to aid in restoring  
21           electric service after disruption and minimize outage times. EEI also provides its member  
22           companies with governing principles for emergency response during major storm events.  
23           These governing principles provide guidelines for costs and expense such as wages, travel,

1 living expenses, replacement costs for materials and supplies expended, and repair or  
2 replacement costs of damaged or lost equipment. EEI also provides a coordinating function  
3 between members and strategic communication support aimed at ensuring customers have  
4 the most up-to-date information on safety and restoration.

#### 5 Grid Security

6 EEI is leading the industry in efforts to partner with the federal government and the North  
7 American Electric Reliability Corporation to address new cybersecurity threats. EEI  
8 through the Electricity Subsector Coordinating Council launched a Cyber Mutual  
9 Assistance Program to provide emergency cyber assistance with the electric and natural  
10 gas industries. The benefit to customers is the increased reliability and reduced outage  
11 duration in the event of cybersecurity outage. This can also include a reduction or  
12 elimination of expenses incurred to restore power as a result of a successful cyber-attack

#### 13 Financial

14 EEI supports electric and gas companies in providing more uniform and consistent data  
15 and information to the financial sectors. Consistent information allows for a better  
16 evaluation between companies and provides a picture of the Company's financial health.  
17 This benefits the Company and customers when financing debt to ensure the rates charged  
18 to the Company are fair and comparable to the rest of the industry.

#### 19 Meetings

20 EEI offers dozens of meetings and conferences each year, providing information, data  
21 exchange, and idea exchange. This is also an ideal forum for policy discussions aimed at  
22 ensuring the continued provision of affordable, reliable energy in a rapidly change world,  
23 which is a key benefit of these meetings for the electric customer. With this forum, the



1 Company can respond to changes in the industry more quickly and take advantage of new  
2 energy savings ideas and technology.

3 **Q. WHAT IS THE AMOUNT OF EEI EXPENSE DURING THE TEST YEAR AND IS**  
4 **ANY AMOUNT BEING EXCLUDED?**

5 A. Kentucky Power was allocated \$113,350 for its 2025 membership dues to EEI. Of that total  
6 amount, the Company is including \$92,667 in the cost-of-service. The amount related to  
7 legislative influencing activities removed from the cost-of-service was \$20,683.

8 However, a change was made to the way EEI dues are expensed in 2025. In  
9 previous years, the EEI bill was paid in full in February. For 2025, the bill was still paid in  
10 February but was then reversed and reclassified to a prepayment account on the balance sheet  
11 to be amortized at \$7,722 monthly over the course of 12 months. Therefore, during the test  
12 year only \$38,611, or five months of amortization is recognized. Accordingly, as part of  
13 the Miscellaneous Expense Adjustment, the Company is including an *increase* of \$54,056  
14 to the FERC 930.2 account to annualize the test year expense level of EEI costs.

15 **Q. WHAT OTHER MISCELLANEOUS EXPENSES ARE REASONABLE TO**  
16 **INCLUDE IN THE COMPANY'S COST-OF-SERVICE?**

17 A. I am also supporting the inclusion in the Company's cost-of-service certain expenses in the  
18 FERC 930 account not addressed above. The FERC 930.1 account is defined as "General  
19 Advertising Expenses," and the FERC 930.2 account is defined as "Miscellaneous General  
20 Expenses." During the test year there was \$338,017 booked to the FERC 930 account. Of  
21 this, the Company is proposing to *include* \$229,158 in the cost-of-service and *exclude*  
22 \$108,859 of that total from the cost-of-service.

1 Listed below are the sub accounts that comprise the FERC 930 account with rationale for  
2 inclusion or exclusion in the cost-of-service.

- 3 • 9301000 (General Advertising Expense): These expenses are related to  
4 advertising and related activities not provided for elsewhere. The total amount  
5 charged to this account during the test year was \$36,775. After review, the  
6 Company is proposing to recover \$2,575 in charges related to economic  
7 development. *The Company is not seeking recovery of the remaining \$34,200.*
- 8 • 9301001 (Newspaper Advertising Space): Expenses in this account are related  
9 to advertising space in newspapers for institutional and goodwill advertising.  
10 The total amount charged to this account during the test year was \$25,915. *The*  
11 *Company is not requesting recovery of these charges.*
- 12 • 9301003 (TV Station Advertising Time): These expenses are related to  
13 television station advertising time for announcements and presentations to  
14 improve public relations. The total amount charged to this account during the  
15 test year was \$22,639. *The Company is not requesting recovery of these*  
16 *charges.*
- 17 • 9301006 (Special Corporate Communication Information Projects): These  
18 expenses are related to special corporate communications, events, and public  
19 relations projects. The total amount charged to this account during the test year  
20 was \$17,099. *The Company is not requesting recovery of these charges.*
- 21 • 9301007 (Special Advertising Space & Production Expense): Expenses in this  
22 account are related to production costs in association with public relations

1 events. The total amount charged to this account during the test year was \$750.

2 *The Company is not requesting recovery of these charges.*

- 3 • 9301012 (Public Opinion Surveys): The expenses in this account are incurred  
4 in connection with conducting public opinion surveys. This survey information  
5 is vital to improving interaction with customers and the public. The total amount  
6 charged to this account during the test year was \$12,842 and *the Company is*  
7 *proposing recovery of the entire amount.*

- 8 • 9301015 (Other Corporate Communication Expense): These expenses are  
9 related to public affairs activities not elsewhere provided. The charges are  
10 related to listing the Company in phone directories, so customers may contact  
11 the Company about electric service and is vital to its operations. The total  
12 amount charged to this account during the test year was \$4,758 and *the*  
13 *Company is proposing to recover the entire amount.*

- 14 • 9302000 (Miscellaneous General Expenses): These expenses are incurred in  
15 connection with general management of the utility. These costs include  
16 corporate memberships such as industry dues to EEI and other organizations.  
17 The charges included for recovery are dues to professional and civic  
18 organizations such as area Chambers of Commerce. Participating with these  
19 organizations improves working relations with the community and business  
20 partners. EEI dues are included in this account and the benefits to working with  
21 EEI are stated above in my Direct Testimony. The total amount charged to this  
22 account during the test year was \$123,956, *of which the Company is proposing*  
23 *to recover \$115,701.*

- 1           • 9302003 (Corporate & Fiscal Expenses): These expenses are incurred in  
2           connection with Corporate and Fiscal expenses of the utility. Expenses include  
3           but are not limited to reports to Regulatory Commissions and Public Notices of  
4           financial, operating, and other data required by regulatory statutes. These  
5           expenses are vital to normal business operation of the Company. The total  
6           amount charged to this account during the test year was \$16,220 *and the*  
7           *Company is proposing to recover the entire amount.*
- 8           • 9302007 (Associated Business Development Expense): These expenses are  
9           related to Associated Business Development where the Company is acting as  
10          the contractor to a customer. The Company supplies labor, such as engineering  
11          and material to provide for the energy needs of the customer. This is a  
12          fundamental resource that the Company provides to customers who do not have  
13          the expertise for the work necessary. The total amount charged to this account  
14          during the test year was \$77,221 *and the Company proposes to recover the*  
15          *entire amount.*

16          Figure JDC-1 details the proposed recoverable and non-recoverable amounts for the 930  
17          accounts.

<b>Figure JDC-1</b>			
<b><u>FERC 930 Account</u></b>	<b><u>Total Expense</u></b>	<b><u>Recoverable</u></b>	<b><u>Eliminated</u></b>
<b>9301000</b>	\$36,775	\$2,575	\$34,200
<b>9301001</b>	\$5,915	\$ -	\$25,915
<b>9301003</b>	\$22,639	\$ -	\$22,639
<b>9301006</b>	\$17,099	\$ -	\$17,099
<b>9301007</b>	\$750	\$ -	\$750
<b>9301012</b>	\$12,842	\$12,842	\$ -
<b>9301015</b>	\$4,758	\$4,758	\$ -
<b>9302000</b>	\$123,956	\$115,701	\$8,256
<b>9302003</b>	\$16,220	\$16,220	\$ -
<b>9302006</b>	(\$158)	(\$158)	\$ -
<b>9302007</b>	\$77,221	\$77,221	\$ -
<b>Sub-Total FERC 930</b>	<b>\$338,017</b>	<b>\$229,158</b>	<b>\$108,859</b>

The charges listed and described above are necessary and justified to ensure the Company delivers efficient and reliable service, and thus should be part of the Company's service costs.

**Q. HOW DID THE COMPANY REVIEW THE FERC 930 ACCOUNTS TO DETERMINE AMOUNTS TO INCLUDE OR EXCLUDE?**

A. Under my direction, a report showing all activity within the 930.1 and 930.2 FERC accounts during the test year was prepared. This report showed 165 lines of accounts payable transactions totaling \$338,017. The Company next isolated the review to transaction amounts greater than \$250. The rationale for this decision is two-fold: 1) transactions less than \$250 total only \$3,805 or 1.1% of the total amount; but 2) constitute 48.5% or 80 of the 165 total transactions. Exhibit JDC-5 provides the report detailing all activity within the FERC 930.1 and 930.2 accounts with detailed descriptions of each transaction, including the recipient.

After isolating the review, I acquired all invoices greater than \$250 and reviewed each expense activity for prudence and determined the amounts to be included or excluded

1 from the cost-of-service. The invoices greater than \$250 proposed for inclusion in the cost-  
2 of-service are provided in Exhibit JDC-6.

**VIII. CONCLUSION**

3 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

4 A. Yes, it does.

## VERIFICATION

The undersigned, John D. Cullop, being duly sworn, deposes and says he is the Regulatory Consultant Senior 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.

  
\_\_\_\_\_  
John D. Cullop

Commonwealth of Kentucky )  
                                                  )  
County of Boyd )

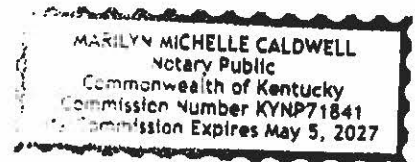
Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John D. Cullop, on August 26, 2025.

  
\_\_\_\_\_  
Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841





An **AEP** Company

BOUNDLESS ENERGY™

**DELIVERED VIA EMAIL TO PSCED@KY.GOV**

November 18, 2024

Linda Bridwell  
Executive Director  
Public Service Commission of Kentucky  
211 Sower Boulevard  
Frankfort, Kentucky 40602

**RE: Monthly Environmental Surcharge Report**

Dear Ms. Bridwell,

Pursuant to KRS 278.183(3), Kentucky Power Company files the Environmental Surcharge Report for the month of October 2024 to be billed in December 2024.

Relevant to this filing are two items related to the Company's approved Environmental Compliance Plan. The Commission's July 15, 2021 Order in Case No. 2021-00004 authorized Kentucky Power Company's request to construct environmental projects to comply with the CCR Rule and the May 2, 2022 Order authorized a 20% depreciation rate for this project.

**Wastewater Ponds Went Into Service**

On September 10, 2024, the wastewater ponds were placed into service. Accordingly, the following updates to Form 3.10 were made consistent with the Commission's above Orders:

- Lines 1 through 4 (calculation of net plant) - began inclusion of these costs;
- Line 13 (construction work in progress) - ceased inclusion of this project;
- Line 38 (monthly depreciation expense) - ensured that the wastewater ponds were not captured within this line as it has a unique depreciation rate; and
- Line 40 (monthly CCR depreciation expense) - began inclusion in this line based on the 20% rate approved by the Commission in its May 2, 2022 Order in Case No. 2021-00004.



### Federal EPA's Revised CCR Rule

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities (“legacy CCR surface impoundments”) as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land (“CCR management units”). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material (“closure in place”) or the CCR material may be excavated and placed in a compliant landfill (“closure by removal”). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method. AEP, with Kentucky Power, evaluated the applicability of the rule to current and former plant sites and Kentucky Power recorded incremental asset retirement obligation (“ARO”) in the second quarter of 2024, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the CCR Rule. As further groundwater monitoring and other analysis is performed, management expects to refine the assumptions and underlying cost estimates used in recording the ARO. These refinements may include, but are not limited to, changes in the expected method of closure, changes in estimated quantities of CCR at each site, the identification of new CCR management units, among other items.

AROs are recognized for legal obligations associated with the retirement of property, plant and equipment. When recording an ARO, the present value of the projected liability is recognized in the period in which the legal obligation is incurred or enacted, if a reasonable estimate of fair value can be made. The liability is accreted over time. For operating facilities, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired facilities, the present value of the liability is expensed, and where future recovery through rates is probable, the present value of the liability is subsequently deferred as a regulatory asset. The present value of the initial ARO and subsequent updates are based on discounted cash flows, which include estimates regarding timing of future cash flows, discount rates and cost escalation rates. These estimates are subject to change. Depreciation expense is adjusted prospectively for any changes to the carrying amount of the associated asset.

In the third quarter of 2024, Kentucky Power began recognizing ARO accretion expense and ARO depreciation expense related to incremental ARO associated with the Federal EPA's Revised CCR Rule. Based on the Commission's May 2, 2022 Order in Case No. 2021-00004, costs associated with Mitchell Plant, specifically costs of CCR compliance, are recoverable through the Company's Environmental Surcharge. Accordingly, Form 3.10 was further updated this month to include on a going forward basis Line 41 (monthly legacy CCR Rule – ARO depreciation and accretion expense).

If there are any questions, please contact me at 606-327-2609.

Sincerely,

A handwritten signature in blue ink that reads "Lerah Kahn". The signature is written in a cursive, flowing style.

Lerah Kahn  
Manager of Regulatory Services

Attachments

**Kentucky Power Company**  
**Environmental Base Revenue Requirement (BRR)**

Ln No.	Month / Year	Mitchell Non- FGD	Gain or Loss on Sale of Allowances	Adjusted Environmental Base	2023-00159 Current Enironmental Base
(1)	(2)	(3)	(4)	(5) =(3)-(4)	
1	24-Jun	\$ 2,825,006	\$ -	\$ 2,825,006	\$2,644,974
2	24-Jul	\$ 2,815,870	\$ -	\$ 2,815,870	\$2,594,563
3	24-Aug	\$ 2,808,114	\$ -	\$ 2,808,114	\$2,741,097
4	24-Sep	\$ 2,847,917	\$ 180,714	\$ 2,667,203	\$2,508,995
5	24-Oct	\$ 3,372,548	\$ -	\$ 3,372,548	\$2,376,639
6	24-Nov	\$ 3,258,712	\$ -	\$ 3,258,712	\$2,423,992
7	24-Dec	\$ 3,306,420	\$ -	\$ 3,306,420	\$2,597,739
8	25-Jan	\$ 3,431,790	\$ -	\$ 3,431,790	\$3,022,418
9	25-Feb	\$ 3,493,649	\$ -	\$ 3,493,649	\$2,558,332
10	25-Mar	\$ 3,165,974	\$ -	\$ 3,165,974	\$2,621,611
11	25-Apr	\$ 3,567,107	\$ 7	\$ 3,567,100	\$2,519,828
12	25-May	\$ 3,262,891	\$ -	\$ 3,262,891	\$2,514,284
13	<b>Total</b>	<b>\$ 38,155,999</b>	<b>\$ 180,721</b>	<b>\$ 37,975,278</b>	<b>\$31,124,472</b>

## 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.

### 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), Demand Charge (if applicable), Fuel Adjustment Clause, System Sales Clause, Demand-Side Management Adjustment Clause, Federal Tax Cut, Residential Energy Assistance, Purchase Power Adjustment, and Generation 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, Kentucky Economic Development Surcharge, Purchase Power Adjustment, and Generation Rider.

#### 1. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

$$\begin{array}{llll} \text{Where:} & E(m) & = & \text{CRR-BRR} \\ & \text{CRR} & = & \text{Current Period Revenue Requirement for the Expense} \\ & \text{BRR} & = & \text{Month.} \\ & & & \text{Base Period Revenue Requirement.} \end{array}$$

#### 2. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month	Base Net Environmental Costs
January	\$ 3,431,790
February	3,493,649
March	3,165,974
April	3,567,100
May	3,262,891
June	2,825,006
July	2,815,870
August	2,808,114
September	2,667,203
October	3,372,548
November	3,258,712
December	\$ 3,306,420
	\$ 37,975,278

*Continued on Sheet 33-2*

DATE OF ISSUE: August 29, 2025

DATE EFFECTIVE: Services Rendered On And After March 1, 2026

ISSUED BY: /s/ Tanner S. Wolffram

TITLE: Director, Regulatory Services

By Authority of an Order of the Public Service Commission

In Case No.: 2025-00257 Dated XXXX XX, XXXX

### Tariff E.S. Continued (Environmental Surcharge)

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.

3. Current Period Revenue Requirement, CRR

$$CRR = [(RB_{KP(c)})(ROR_{KP(c)} / 12) + OE_{KP(c)} - AS]$$

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.
- AS = Net proceeds from the sale of Title IV and CSAPR SO<sub>2</sub> emission allowances, ERCs, and NO<sub>x</sub> emission allowances, reflected in the month of receipt.

“KP(C)” identifies components from Mitchell Units – Current Period.

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 and cash working capital allowance based on the net operations and maintenance expense lead days of 19.82 authorized in Case No. 2025-00257. 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.

T

The Rate of Return for Kentucky Power is 10.0% rate of return on equity as authorized by the Commission in its Order Dated XXXX XX, XXXX, Case No. 2025-00257.

I

T

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 33-3*

T

DATE OF ISSUE: August 29, 2025  
 DATE EFFECTIVE: Services Rendered On And After March 1, 2026  
 ISSUED BY: /s/ Tanner S. Wolfram  
 TITLE: Director, Regulatory Services  
 By Authority of an Order of the Public Service Commission  
 In Case No.: 2025-00257 Dated XXXX XX, XXXX

### 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:

$$\begin{aligned} \text{(m)} &= \text{the expense month.} \\ \text{(b)} &= \text{the most recent calendar year revenues} \end{aligned}$$

#### 5. Environmental Surcharge Factor

$$\text{Residential Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{RA(m)}}{\text{KY RR(m)}}$$

$$\text{All Other Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)} * \text{AO(m)}}{\text{KY OR(m)- KY OF(m)}}$$

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 33-4*

T

DATE OF ISSUE: August 29, 2025  
 DATE EFFECTIVE: Services Rendered On And After March 1, 2026  
 ISSUED BY: /s/ Tanner S. Wolfram  
 TITLE: Director, Regulatory Services  
By Authority of an Order of the Public Service Commission  
In Case No.: 2025-00257 Dated XXXX XX, XXXX

### 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<sub>2</sub> 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<sub>2</sub> allowances
- costs associated with the consumption of NO<sub>x</sub> allowances
- return on NO<sub>x</sub> 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 associated with ARO (Asset Retirement Obligations) depreciation and accretion.

DT

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<sub>x</sub> burners, Low NO<sub>x</sub> burner Modification, SCR, FGD, Landfill, Coal Blending Facilities and SO<sub>3</sub> 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.

DATE OF ISSUE: August 29, 2025  
 DATE EFFECTIVE: Services Rendered On And After March 1, 2026  
 ISSUED BY: /s/ Tanner S. Wolffram  
 TITLE: Director, Regulatory Services  
By Authority of an Order of the Public Service Commission  
In Case No.: 2025-00257 Dated XXXX XX, XXXX

**SAMPLE ONLY**

**KENTUCKY POWER COMPANY**  
**Environmental Surcharge**  
**Form 1.00 - Summary**

**Month Ended:** **X**

Residential Environmental  
Surcharge Factor      =       $\frac{X}{X}$       =

All Other Classes  
Environmental Surcharge      =       $\frac{X}{X}$       =

Effective Date for Billing       $\frac{X}{\hspace{10em}}$

Submitted by:       $\frac{\hspace{10em}}{\hspace{10em}}$   
(Signature)

Title:       $\frac{X}{\hspace{10em}}$

Date Submitted:       $\frac{X}{\hspace{10em}}$



**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	
	<b>SURCHARGE FACTORS</b>	<b>Residential</b>	<b>All Other Classifications</b>
9	Allocation Factors, % of revenue during previous Calendar Year	X	X
10	Current Month's Allocation E(m) (Line 8* Line 9)	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**

<b>Billing Month</b>	<b>Base Environmental Costs</b>
January	X
February	X
March	X
April	X
May	X
June	X
July	X
August	X
September	X
October	X
November	X
December	<u>X</u>
<b>TOTAL</b>	<b>X</b>

**SAMPLE ONLY**

**KENTUCKY POWER COMPANY**  
**Environmental Surcharge**  
**Form 3.00 - Calculation of Current Environmental Revenue Requirement**

Line No.	COMPONENTS		
1	<b>First Component:</b> Mitchell Non-FGD expenses (Form 3.10)		X
2	<b>Second Component:</b> Net Proceeds from Emission Allowances Sales		
	a) CAIR SO <sub>2</sub> - EPA Auction Proceeds received during Expense Month	X	
	b) CSAPR SO <sub>2</sub> - Net Gain or (Loss) from Allowance Sales, received during Expense Month	X	
	Total Net Proceeds from SO <sub>2</sub> Allowances	X	
	c) NO <sub>x</sub> - EPA Auction Proceeds, received during Expense Month	X	
	d) NO <sub>x</sub> - Net Gain or (Loss) from NO <sub>x</sub> Allowances Sales, received during Expense Month	X	
	Total Net Proceeds from NO <sub>x</sub> 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 SO2 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	<b>Total Rate Base</b>		X	X	X
18	***WACC for Non-FGD Rate Base as of 3/31/2023	9.14%	X		X
19	***WACC for FGD and Non-FGD Additions to 3/31/2023 Rate Base	9.14%	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 SO2 Consumption **		X	X	X
32	CSAPR Annual NOx Consumption		X	X	X
33	CSAPR Seasonal NOx consumption		X	X	X
34	<b>Total Monthly Operation Costs</b>		X	X	X
35	Monthly FGD Maintenance Expense		X	X	X
36	Monthly Non-FGD Maintenance Expense		X	X	X
37	<b>Total Monthly Maintenance Expense</b>		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 ARO Depreciation and Accretion Expense		X	X	X
42	Monthly Property Tax		X	X	X
43	<b>Total Monthly Other Expenses</b>		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	<b>Gross-up for Uncollectible Expense &amp; KPSC Maint Fee</b>	1.338493	X	X	X
48	<b>Total Revenue Requirement</b>		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)
1	L/T DEBT	\$853,662,190	53.87%	5.49%		2.96%	1.004437		2.97%
2	S/T DEBT	\$0	0.00%						
3									
4	C EQUITY	\$731,091,478	46.13%	10.00%	*	4.61%	1.338493		6.17%
5	TOTAL	\$1,584,753,668	100.00%			7.57%			9.14%

		<u>Debt</u>	<u>Equity</u>
6	Operating Revenues	100.0000	100.0000
7	Less Uncollectible Accounts Expense	0.2822	0.2822
8	KPSC Maintenance Assessment Fee	0.1595	0.159500
9	Income Before Income Taxes	99.5583	99.5583
10	Less State Income Taxes (Ln 4 x 5.0097)		4.9876
11	Taxable Income for Federal Income Taxes		94.5707
12	Less Federal Income Taxes (Ln 11*21%)		19.8599
13	Operating Income Percentage		74.7109
14	Gross Up Factor (100.00/Ln 9)	1.004437	1.338493

**SAMPLE ONLY**

**KENTUCKY POWER COMPANY**  
**Environmental Surcharge**  
**Form 3.30 - Mitchell Plant Original Plant and Accumulated Depreciation**

<b>Plant</b>	<b>Description</b>	<b>Total In Service Cost</b>	<b>Accumulated Depreciation</b>
Mitchell	<b>FGD</b>	<b>X</b>	<b>X</b>
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	<b>Non-FGD Total</b>	<b>X</b>	<b>X</b>

**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
<i>Additions</i>					
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
<i>Withdrawals</i>					
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 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
<i>Additions</i>					
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
<i>Withdrawals</i>					
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
<i>Additions</i>					
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
<i>Withdrawals</i>					
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
<i>Additions</i>					
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
<i>Withdrawals</i>					
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**

<b>Line</b>	<b>Month/Year</b>	<b>Mitchell Non-FGD</b>	<b>Mitchell FGD</b>
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

**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%	<b>X%</b>
2	All Other Classes	\$X	X%	<b>X%</b>
3	Total Retail Revenues	\$X	X%	<b>X%</b>
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

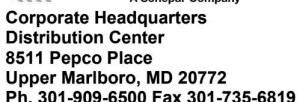
Residential				
Month	Total Revenues	Decommissioning Rider Revenues	Environmental Surcharge Revenues	Non-Percentage of Revenue Rider Revenues
(1)	(2)	(3)	(4)	(5) (2)-(3)-(4)
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
MM YYYY	X	X	X	X
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
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

Reviewed by	Business Unit	Business Description	Month	PERC Account	Account Name	Dept ID	Project ID	Cost Component	ABM	Vendor Name	Vendor ID	Monetary Amount	Recoverable	Reason
	110	SHSVC	6/2024	930	9302006 Assoc Bus Dev - Materials Sold	11206	EDN102240	391	214	0000330372 CAPITAL ELECTRIC	00340670	(158.00)	YES	Normal Business Operation
	110	DISTR	6/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00340662	0.12	NO	Public Relations
	110	DISTR	7/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00340699	0.42	NO	Public Relations
	110	DISTR	7/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00341348	0.42	NO	Public Relations
	110	DISTR	8/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00341637	0.42	NO	Public Relations
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00342409	0.42	NO	Public Relations
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00342898	0.42	NO	Public Relations
	110	DISTR	12/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00343563	0.42	NO	Public Relations
	110	DISTR	2/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00343563	0.42	NO	Public Relations
	110	DISTR	3/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00343563	0.42	NO	Public Relations
	110	DISTR	3/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00343563	0.42	NO	Public Relations
	110	DISTR	6/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00340662	1.99	NO	Public Relations
	110	DISTR	12/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	393	293	0000161803 BANK OF AMERICA	00343758	2.23	NO	Public Relations
	110	DISTR	3/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00342898	2.86	NO	Public Relations
	110	DISTR	3/2025	930	9301006 Spec Corporate Comm Info Proj	12394	EDNANDA	396	299	0000161803 BANK OF AMERICA	00344067	3.98	NO	Public Relations
	110	DISTR	7/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	960	293	0000161803 BANK OF AMERICA	00343758	5.79	NO	Public Relations
	110	DISTR	7/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00340699	6.99	NO	Public Relations
	110	DISTR	8/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00341348	6.99	NO	Public Relations
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00341637	6.99	NO	Public Relations
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00342409	6.99	NO	Public Relations
	110	DISTR	12/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00342898	6.99	NO	Public Relations
	110	DISTR	2/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00343563	6.99	NO	Public Relations
	110	DISTR	3/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00343563	6.99	NO	Public Relations
	110	DISTR	4/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	00343563	6.99	NO	Public Relations
	110	DISTR	5/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	290	293	0000161803 BANK OF AMERICA	00343898	6.99	NO	Public Relations
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	960	293	0000161803 BANK OF AMERICA	00344341	6.99	NO	Public Relations
	110	DISTR	9/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00344823	6.99	NO	Public Relations
	103	DISTR	9/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	290	293	0000161803 BANK OF AMERICA	00342409	12.05	NO	Public Relations
	110	DISTR	6/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	00341875	12.26	NO	Public Relations
	110	DISTR	6/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	02765804	13.36	YES	Phone Book Listing Service
	103	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	290	293	0000161803 BANK OF AMERICA	00340846	14.96	NO	Public Relations
	103	DISTR	10/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	00342409	15.26	NO	Public Relations
	110	DISTR	3/2025	930	9301006 Spec Corporate Comm Info Proj	12394	EDNANDA	994	299	0000330088 DSI SOLUTIONS LLC	02769987	16.36	YES	Phone Book Listing Service
	110	DISTR	6/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00344067	23.28	NO	Public Relations
	103	DISTR	7/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	00343071	24.92	NO	Public Relations
	103	DISTR	11/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	02757978	32.22	YES	Phone Book Listing Service
	103	DISTR	12/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	02774024	32.26	YES	Phone Book Listing Service
	103	DISTR	2/2025	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	02781110	32.26	YES	Phone Book Listing Service
	103	DISTR	3/2025	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	0284325	32.26	YES	Phone Book Listing Service
	103	DISTR	4/2025	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	02788430	32.26	YES	Phone Book Listing Service
	103	DISTR	5/2025	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	0292664	32.26	YES	Phone Book Listing Service
	103	DISTR	2/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	396	293	0000161803 BANK OF AMERICA	0296449	32.26	YES	Phone Book Listing Service
	110	DISTR	7/2024	930	9302007 Assoc Business Development Exp	11439	EDN102170	210	210	0000333894 SPARKS & MAGIC PLLC	00343758	37.17	NO	Public Relations
	110	DISTR	8/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	960	293	0000333894 SPARKS & MAGIC PLLC	00344410	39.95	YES	Normal Business Operation
	103	DISTR	8/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000330088 DSI SOLUTIONS LLC	00344716	40.80	YES	Normal Business Operation
	110	DISTR	3/2025	930	9301006 Spec Corporate Comm Info Proj	12394	EDNANDA	994	299	0000161803 BANK OF AMERICA	00344067	42.40	NO	Public Relations
	110	DISTR	4/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00344341	45.40	NO	Public Relations
	110	DISTR	5/2025	930	9301003 TV Station Advertising Time	12394	EDNANDA	960	293	0000161803 BANK OF AMERICA	00343563	49.67	NO	Public Relations
	110	DISTR	9/2024	930	9302007 Assoc Business Development Exp	13450	EDN102170	393	214	5105157901 CURRENT LIGHTING SOLUTIONS LLC	00344823	49.95	NO	Advertising
	110	DISTR	11/2024	930	9302007 Assoc Business Development Exp	13450	EDN102170	393	214	5105157901 CURRENT LIGHTING SOLUTIONS LLC	M4674770	51.62	NO	Public Relations
	110	DISTR	11/2024	930	9302007 Assoc Business Development Exp	13450	EDN102170	393	293	0000330372 CAPITAL ELECTRIC	00342628	55.81	NO	Public Relations
	110	TRANS	4/2025	930	9302007 Assoc Business Development Exp	11206	ETN901007	393	177	0000330372 CAPITAL ELECTRIC	00344433	70.77	YES	Normal Business Operation
	110	DISTR	6/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00343758	71.46	NO	Public Relations
	110	DISTR	9/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00340662	75.00	NO	Public Relations
	110	DISTR	9/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	290	293	0000161803 BANK OF AMERICA	00341875	75.00	NO	Public Relations
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	290	293	0000161803 BANK OF AMERICA	00341875	75.00	NO	Public Relations
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00342409	75.00	NO	Public Relations
	110	DISTR	8/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000333894 SPARKS & MAGIC PLLC	00342409	75.00	NO	Public Relations
	110	DISTR	2/2025	930	9302007 Assoc Business Development Exp	11439	EDN102170	210	210	0000333894 SPARKS & MAGIC PLLC	00343652	80.75	YES	Normal Business Operation
	110	DISTR	12/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00342898	82.14	NO	Public Relations
	110	DISTR	12/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	994	293	0000161803 BANK OF AMERICA	00342409	83.00	NO	Public Relations
	110	DISTR	12/2024	930	9301006 Spec Corporate Comm Info Proj	12394	EDNANDA	994	299	0000161803 BANK OF AMERICA	00344067	92.00	NO	Public Relations
	110	DISTR	3/2025	930	9301006 Spec Corporate Comm Info Proj	12394	EDNANDA	396	299	0000333894 SPARKS & MAGIC PLLC	0034189	111.49	NO	Public Relations
	110	DISTR	12/2024	930	9302007 Assoc Business Development Exp	11439	EDN102170	210	210	0000333894 SPARKS & MAGIC PLLC	00343965	138.55	YES	Normal Business Operation
	110	DISTR	6/2024	930	9301001 Newspaper Advertising Space	12394	EDN102170	210	210	000072088 APPALACHIAN NEWS EXPRESS	00340664	150.00	NO	Public Relations
	110	DISTR	2/2025	930	9302007 Assoc Business Development Exp	11439	EDN102170	210	210	0000333894 SPARKS & MAGIC PLLC	00343652	151.30	YES	Normal Business Operation
	110	DISTR	12/2024	930	9302007 Assoc Business Development Exp	11439	EDN102170	210	210	0000333894 SPARKS & MAGIC PLLC	00342833	185.30	YES	Normal Business Operation
	110	DISTR	3/2025	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000203830 BERRY NETWORK INC	00344078	191.09	YES	Phone Book Listing Service
	110	DISTR	10/2024	930	9301015 Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000203830 BERRY NETWORK INC	00342147	194.97	YES	Phone Book Listing Service
	110	DISTR	5/2025	930	9302007 Assoc Business Development Exp	11439	EDN102170	210	210	0000333894 SPARKS & MAGIC PLLC	00344716	199.75	YES	Normal Business Operation
	110	DISTR	10/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	960	294	000043668 MOUNTAIN BROADCASTING SERVICE	F00342482	200.00	NO	Public Relations
	140	TCOMM	6/2024	930	9301003 TV Station Advertising Time	12394	ECN103652	210	409	5105042501 BROADWAY ELECTRIC SERVICE COMP	M4221148	202.28	YES	Normal Business Operation
JDC	110	DISTR	7/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	290	293	0000161803 BANK OF AMERICA	00340699	250.00	NO	Advertising
	110	DISTR	7/2024	930	9301003 TV Station Advertising Time	12394	EDNANDA	290	293	0000161803 BANK OF AMERICA	00341274	250.00	NO	Advertising

JDC	110	DISTR	10/2024	930	9301003	TV Station Advertising Time	12394	ENDANDA	960	294	0000045688	APPALACHIAN NEWS EXPRESS	00342487	25000	NO	Public Relations
JDC	110	DISTR	2/2025	930	9301003	Newspaper Advertising Space	12394	ENDANDA	960	293	0000072088	APPALACHIAN NEWS EXPRESS	00343563	25000	NO	Public Relations
JDC	110	DISTR	10/2024	930	9301003	TV Station Advertising Time	12394	ENDANDA	960	293	0000161803	BANK OF AMERICA	00342487	25430	NO	Public Relations
JDC	110	DISTR	4/2025	930	9302007	Assoc Business Development Exp	12394	ENDANDA	396	293	0000161803	BANK OF AMERICA	00344419	26016	YES	Normal Business Operation
JDC	110	DISTR	12/2024	930	9302007	Assoc Business Development Exp	1439	END102170	210	210	0000031394	SPARKS & MAGIC PLIC	00343169	27830	YES	Normal Business Operation
JDC	110	TCOMM	9/2024	930	9302007	Assoc Business Development Exp	1523	ECN103052	210	409	5104835501	ATALENT SERVICES LLC	00343698	28560	YES	Phone Book Listing Service
JDC	110	DISTR	6/2024	930	9301015	Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000201830	BERRY NETWORK INC	00340762	28906	YES	Normal Business Operation
JDC	110	DISTR	2/2025	930	9301015	Other Corporate Comm Exp	11115	PHONEBOOK	210	177	5104835501	ATALENT SERVICES LLC	00343525	37260	YES	Phone Book Listing Service
JDC	110	DISTR	2/2025	930	9301015	Other Corporate Comm Exp	11149	PHONEBOOK	960	294	0000201830	BERRY NETWORK INC	00343564	60237	YES	Phone Book Listing Service
JDC	110	DISTR	2/2025	930	9301015	Newspaper Advertising Space	12394	ENDANDA	960	293	0000045691	MOUNTAIN CITIZEN	00343732	66150	NO	Public Relations
JDC	110	DISTR	7/2024	930	9301015	Newspaper Advertising Space	12394	ENDANDA	960	293	0000201830	BERRY NETWORK INC	00342658	74496	YES	Phone Book Listing Service
JDC	110	DISTR	2/2025	930	9301015	Other Corporate Comm Exp	11149	PHONEBOOK	960	479	0000045691	MOUNTAIN CITIZEN	00343732	74496	YES	Phone Book Listing Service
JDC	110	DISTR	2/2025	930	9301007	Special Adv Space & Prod Exp	13453	ENDANDA	960	294	00001035012	LORE PATRICK SHELBY	00343895	75000	NO	Public Relations
JDC	110	DISTR	5/2025	930	9301007	Newspaper Advertising Space	12394	ENDANDA	960	293	0000045691	MOUNTAIN CITIZEN	00344815	75000	NO	Public Relations
JDC	110	DISTR	9/2024	930	9302000	Misc General Expenses	11439	ENDANDA	530	292	0000045691	MOUNTAIN CITIZEN	00341664	75590	NO	Event tickets
JDC	110	TCOMM	12/2024	930	9302007	Assoc Business Development Exp	12753	ECN103052	210	409	5104835501	ATALENT SERVICES LLC	00345069	85680	YES	Normal Business Operation
JDC	110	DISTR	2/2025	930	9301007	Newspaper Advertising Space	12394	ENDANDA	960	293	0000045691	MOUNTAIN CITIZEN	00344464	90000	NO	Public Relations
JDC	110	DISTR	2/2025	930	9301007	Newspaper Advertising Space	12394	ENDANDA	960	293	0000045691	MOUNTAIN CITIZEN	00344770	90000	YES	Normal Business Operation
JDC	110	DISTR	11/2024	930	9301007	Newspaper Advertising Space	12394	ENDANDA	960	293	0000161803	BANK OF AMERICA	00346278	93013	NO	Employees appreciation
JDC	110	DISTR	2/2025	930	9301007	Newspaper Advertising Space	12394	ENDANDA	960	293	0000161803	BANK OF AMERICA	00346278	93013	NO	Employees appreciation
JDC	110	FINAN	6/2024	930	9302007	Assoc Business Development Exp	13450	END102170	393	214	5105157901	CURRENT LIGHTING SOLUTIONS LLC	00346770	100642	YES	Normal Business Operation
JDC	110	FINAN	11/2024	930	9302007	Assoc Business Development Exp	1408	ECN103052	210	409	5105042501	BROADWAY ELECTRIC SERVICE COMP	00342278	106715	YES	Normal Business Operation
JDC	110	TRANS	4/2025	930	9302003	Corporate & Fiscal Expenses	11389	FANANDA	263	661	0000331012	HUNTINGTON NATIONAL BANK	00342698	11500	YES	Normal Business Operation
JDC	110	TRANS	7/2024	930	9302007	Assoc Business Development Exp	1206	ETN001007	391	177	0000330372	CAPITAL ELECTRIC	00344433	117947	YES	Normal Business Operation
JDC	110	TRANS	7/2024	930	9301000	General Advertising Expenses	12394	ENDANDA	960	294	0000332369	DAILY INDEPENDENT	00341006	12000	NO	Public Relations
JDC	110	DISTR	7/2024	930	9301000	General Advertising Expenses	12394	ENDANDA</								





**INVOICE**  
**S057114538.001**  
**12/03/24**  
**Page 1 of 1**

**SHIPPED TO: 410102**

AMERICAN ELECTRIC POWER - KY  
500 E CLAYTON  
BROWN'S FOOD SERVICE  
PIKEVILLE KY 41501-1515

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**Payment Mailing Address:**  
CAPITAL ELECTRIC  
PO BOX 404749  
ATLANTA GA 30384-4749





# Sparks and Magic, PLLC

## INVOICE

Date: 12/30/2024

Invoice # 24-012KYPWR

Agreement # 03064486X140

Mailing Info: Sparks and Magic, PLLC

2231 Breezy Ridge Rd.

Woodlawn, VA 24382

Phone: (276) 238-0847

Bill To: AEP (KY Power)

Emily Ball / Jason Smith

420 Riverport Rd.

Kingsport, TN 37660

Phone: (423) 723-5358

Hourly Services	Hours	Rate	Amount
Business Unit 110 (Site, Office & Travel)	4.73	\$85.00	\$402.05

Mileage	Miles	Rate	Amount
Mileage	0	\$0.670	\$0.00

Other Services and Charges	Amount
Tolls	
Parking	
Lodging	
Meals	
Entertainment Meals	

	Subtotal	\$402.05
	Tax Rate	0.000%
	Tax Amount \$	-
Other Comments	Total Due	\$402.05
1. Total payment due by 45 days from date of invoice		
2. Please include the invoice number on your check		

Thank You For Your Business!

Make all checks payable to:  
Sparks and Magic, PLLC



ATTN: Trish McCabe / Desiree Canales  
C/O AEP  
850 TECH CENTER DRIVE  
GAHANNA OH 43230

**PLEASE REMIT TO:**  
ACTALENT SERVICES, LLC  
3689 COLLECTION CENTER DRIVE  
CHICAGO IL 60693-0036  
UNITED STATES

**INVOICE**

Invoice No:  
Invoice Date:  
Payment Terms:  
Release No:  
Due Date:

**EEN00633915A**  
4/19/2024  
**Net 45**  
81111215  
6/3/2024

<b>Total Amount</b>	<b>\$228,650.20</b>
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**Contract #:** 027996640000X103 - IT Telecom  
**Reviewer:** ATTN: Trish McCabe / Desiree Canales  
**Approver:** SUNITA MODAK  
**Activity/ Location:** GA Proj Managers ITT-8 (APCO)

For Billing Inquiries contact Ndendet, Flore at: [ndendet@actalent.com](mailto:ndendet@actalent.com)

Work Order	Description	Date Period	Sum of Quantity	Sum of Amount
42394933-02	CharlestonAmos-A14066002-150	02/25/2024 - 03/30/2024	9.00	908.80
42905285-02	CharlestonSheri-P12059029-383	02/25/2024 - 03/30/2024	7.00	722.40
42956588-02	CharlestonNitro-P18255001-383	02/25/2024 - 03/30/2024	10.00	1,081.60
42965341-02	CharlestonBelle-P18039005-383	02/25/2024 - 03/30/2024	12.00	1,268.00
42980152-02	BlufieldJubalEa-A16922008-150	02/25/2024 - 03/30/2024	14.00	1,870.80
42983620-02	BluefieldSourwo-P19070001-383	02/25/2024 - 03/30/2024	13.00	1,758.00
43010000-02	AshlandJackhorn-P18221014-180	02/25/2024 - 03/30/2024	14.00	1,870.80
43018223-02	CharlestonJarre-P17026007-383	02/25/2024 - 03/30/2024	6.00	629.20
K10284564-001	AFL KYTR REMED-ECNMTPT01-384	02/25/2024 - 03/30/2024	5.00	744.00
K10289664-001	AFL APCO REMED-ECNMTPT01-140	02/25/2024 - 03/30/2024	56.00	7,128.00
K10362198-001	Logan Cty-ITCT14022-140	02/25/2024 - 03/30/2024	9.00	1,315.20
K10430731-001	Clinch River-ITCB1500-215	02/25/2024 - 03/30/2024	4.00	699.60
K10432163-001	Bluefield SC-ITCB14000-140	02/25/2024 - 03/30/2024	9.00	1,058.40
K10482178-001	RBB DEHUE CES-ITCT14022-140	02/25/2024 - 03/30/2024	4.00	442.80
K10486869-001	RBB MUDFORK CES-ITCT14022-140	02/25/2024 - 03/30/2024	8.00	1,142.40
K10486875-001	RBB HEWETT CES-ITCT14022-140	02/25/2024 - 03/30/2024	6.00	664.20
K10486882-001	RBB HUFFCR CES-ITCT14022-140	02/25/2024 - 03/30/2024	7.00	965.40
K10486886-001	RBB HURRI CES-ITCT14022-140	02/25/2024 - 03/30/2024	3.00	394.20
K10486890-001	RBB MIDKIFF CES-ITCT14022-140	02/25/2024 - 03/30/2024	8.00	1,014.00
K10486893-001	RBB NPOINT CES-ITCT14022-140	02/25/2024 - 03/30/2024	6.00	664.20
K10486906-001	RBB SHARPLES ST-ITCT14022-140	02/25/2024 - 03/30/2024	2.00	221.40
K10486967-001	RBB SHERIDAN ST-ITCT14022-140	02/25/2024 - 03/30/2024	6.00	921.00
K10486973-001	RBB SPRIGG ST-ITCT14022-140	02/25/2024 - 03/30/2024	2.00	221.40
K10486979-001	RBB DINGESS ST-ITCT14022-140	02/25/2024 - 03/30/2024	6.00	664.20
K10488564-001	RBB BORDER ST-ITCT14022-140	02/25/2024 - 03/30/2024	8.00	1,014.00
K10488583-001	RBB STONEBR ST-ITCT14022-140	02/25/2024 - 03/30/2024	2.00	221.40
K10489114-001	RBB LATROBE ST-ITCT14022-140	02/25/2024 - 03/30/2024	6.00	664.20
K10553585-001	RBB CINDER POP-ITCT14022-140	02/25/2024 - 03/30/2024	14.00	1,806.60
K10561254-001	Stone Branch-ITCT14022-140	02/25/2024 - 03/30/2024	19.00	2,358.00
K10561262-001	Chauncey-ITCT14022-140	02/25/2024 - 03/30/2024	24.00	2,913.60
K10561408-001	Hewett Sharp-ITCT14022-140	02/25/2024 - 03/30/2024	26.00	3,263.40
K10561575-001	Dingess -ITCT14022-140	02/25/2024 - 03/30/2024	14.00	1,806.60
K10561575-001	Dingess-ITCT14022-140	02/25/2024 - 03/30/2024	14.00	1,549.80
K10561586-001	Smokehouse-ITCT14022-140	02/25/2024 - 03/30/2024	24.00	2,913.60
K10561587-001	Dehue Huff-ITCT14022-140	02/25/2024 - 03/30/2024	29.00	3,593.40
K10561591-001	Cow Creek-ITCT14022-140	02/25/2024 - 03/30/2024	30.00	3,642.00
K10567233-001	Marrowbone-ITCT14022-140	02/25/2024 - 03/30/2024	26.00	3,199.20
K10567258-001	Myrtle -ITCT14022-140	02/25/2024 - 03/30/2024	14.00	1,870.80
K10567258-001	Myrtle-ITCT14022-140	02/25/2024 - 03/30/2024	12.00	1,328.40
K10567263-001	Musick -ITCT14022-140	02/25/2024 - 03/30/2024	15.00	2,043.60
K10567263-001	Musick-ITCT14022-140	02/25/2024 - 03/30/2024	12.00	1,328.40
K10567265-001	Naugatuck-ITCT14022-140	02/25/2024 - 03/30/2024	27.00	3,372.00
K10567267-001	Sprigg-ITCT14022-140	02/25/2024 - 03/30/2024	26.00	3,327.60
K10567284-001	Vulcan WV-ITCT14022-140	02/25/2024 - 03/30/2024	26.00	3,199.20
K10567291-001	Vulcan KY -ITCT14022-140	02/25/2024 - 03/30/2024	14.00	1,870.80
K10567291-001	Vulcan KY -ITCT14022-140	02/25/2024 - 03/30/2024	12.00	1,328.40
K10567339-001	Breeden Marr-ITCT14022-140	02/25/2024 - 03/30/2024	26.00	3,135.00
K10567345-001	Mountain View-ITCT14022-140	02/25/2024 - 03/30/2024	22.00	2,692.20
K10567477-001	Mohawk-ITCT14022-140	02/25/2024 - 03/30/2024	24.00	2,913.60
T10024273-002	CharlestonHerns-P19205005-383	02/25/2024 - 03/30/2024	8.00	825.20
T10049030-002	Rues Scott ROW-P19204005-150	02/25/2024 - 03/30/2024	8.00	895.20
T10049054-002	CharlestonKinca-P19073015-383	02/25/2024 - 03/30/2024	10.00	1,095.40
T10086571-002	CharlestonKenna-DP19H05Y0-383	02/25/2024 - 03/30/2024	10.00	1,002.00
T10096795-002	BluefieldFortRo-P19293008-150	02/25/2024 - 03/30/2024	8.00	1,014.00
T10118150-002	CharlestonScarb-P19267015-383	02/25/2024 - 03/30/2024	14.00	1,454.40
T10154958-002	BluefieldHockma-DP20H03C1-150	02/25/2024 - 03/30/2024	14.00	1,870.80
T10165851-002	AshlandOsborn-P19036009-180	02/25/2024 - 03/30/2024	14.00	1,742.40
T10301500-002	CharlestonRipple-DP19H05Y5-383	02/25/2024 - 03/30/2024	11.00	1,408.20
T10311720-002	CharlestonHopki-A16803026-383	02/25/2024 - 03/30/2024	15.00	1,687.60
T10317109-002	BluefieldGarden-P19058014-383	02/25/2024 - 03/30/2024	12.00	1,328.40
T10317119-002	BluefieldPadfor-P19058016-383	02/25/2024 - 03/30/2024	4.00	442.80
T10319111-002	CharlestonCraney-P18253020-383	02/25/2024 - 03/30/2024	13.00	1,361.20
T10361150-002	Bros Ext Tline-P21251005-150	02/25/2024 - 03/30/2024	13.00	1,361.20
T10383950-002	AshlandBakerFB-A14068001-180	02/25/2024 - 03/30/2024	4.00	442.80
T10437586-002	Brosvle ext Fbr-P21251012-150	02/25/2024 - 03/30/2024	13.00	1,361.20
T10448194-002	Clf Jms Rvr Fbr-P17081051-150	02/25/2024 - 03/30/2024	14.00	1,454.40
T10465202-002	CharlestonAirpo-DP21H05CS-150	02/25/2024 - 03/30/2024	11.00	1,174.80
T10466422-002	CharlestonChemi-P19163008-383	02/25/2024 - 03/30/2024	10.00	1,081.60
T10496350-002	BluefieldArrowh-P19095026-150	02/25/2024 - 03/30/2024	13.00	1,758.00



ATTN: Trish McCabe / Desiree Canales  
C/O AEP  
850 TECH CENTER DRIVE  
GAHANNA OH 43230

PLEASE REMIT TO:  
ACTALENT SERVICES, LLC  
3689 COLLECTION CENTER DRIVE  
CHICAGO IL 60693-0036  
UNITED STATES

INVOICE

Invoice No:  
Invoice Date:  
Payment Terms:  
Release No:  
Due Date:

EEN00633915A  
4/19/2024  
Net 45  
81111215  
6/3/2024

Z10543675-001	APCO FAMI-ITCT10304-1060	02/25/2024 - 03/30/2024	41.00	5,405.40
R10315708-001	Grundy SC-26444-140	02/25/2024 - 03/30/2024	5.00	615.60
AE000877-01	GreenupATT-ECN103052-140	02/25/2024 - 03/30/2024	8.00	1,142.40
AE000877-01	Greenup TS ABD-ECN103052-110	02/25/2024 - 03/30/2024	2.00	285.60
K10430723-001	Smith Mt. Hydro-ITCB21500-215	02/25/2024 - 03/30/2024	12.00	1,456.80
AE024816-01	Dingess TS KSW-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE024816-01	Dingess TS-ECN103052-140	02/25/2024 - 03/30/2024	2.00	285.60
T10301469-002	BluWildwoodSt2-DP21R02B0-140	02/25/2024 - 03/30/2024	3.00	458.40
T10171944-002	BluFtRobS5-P19293014-382	02/25/2024 - 03/30/2024	4.00	571.20
K10435994-001	Roanoke Ofc -ITCB14000-140	02/25/2024 - 03/30/2024	8.00	885.60
AE009303-01	Lavalette-ECN103052-140	02/25/2024 - 03/30/2024	8.00	1,142.40
R10553570-001	Smith Mtn LCO-26640-215	02/25/2024 - 03/30/2024	4.00	442.80
R10345765-001	Roanoke RDC-26436-150	02/25/2024 - 03/30/2024	11.00	1,279.80
T10186427-002	AshNewCampSt1-P19305022-110	02/25/2024 - 03/30/2024	11.00	1,600.80
K10360186-001	RBB Logan POP-ITCT14022-140	02/25/2024 - 03/30/2024	12.00	1,649.40
K10620830-001	Logan Splicing -ITCT14022-140	02/25/2024 - 03/30/2024	17.00	2,136.60
K10620838-001	Mingo Splicing -ITCT14022-140	02/25/2024 - 03/30/2024	15.00	1,979.40
42956506-02	AshSoftShellSt1-P17083001-180	02/25/2024 - 03/30/2024	4.00	571.20
42956579-02	AshGarrettSt1-P17083006-180	02/25/2024 - 03/30/2024	8.00	1,142.40
T10431854-002	AshEasternSt1-P17083043-180	02/25/2024 - 03/30/2024	5.00	744.00
42904913-01	WPS Teays val-25706-140	02/25/2024 - 03/30/2024	2.00	221.40
K10432085-001	Grundy Off-ITCB14000-140	02/25/2024 - 03/30/2024	4.00	442.80
AE024241-01	DingessWV-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE024241-01	Dingess TS-ECN103052-140	02/25/2024 - 03/30/2024	2.00	285.60
AE024647-01	Burning Rock NS-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE024647-01	Burning Rock TS-EDN102170-140	02/25/2024 - 03/30/2024	2.00	285.60
K10430772-001	Wheeling SC-ITCB21000-210	02/25/2024 - 03/30/2024	12.00	1,456.80
K10435998-001	Roanoke SC-ITCB14000-140	02/25/2024 - 03/30/2024	13.00	1,629.60
K10436001-001	Rocky Mount Ofc-ITCB14000-140	02/25/2024 - 03/30/2024	11.00	1,279.80
K10665276-001	Existing Miles-ITCT14022-140	02/25/2024 - 03/30/2024	16.00	2,028.00
AE025289-01	Newcomerstown-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE025675-01	Salineville-ECN103052-140	02/25/2024 - 03/30/2024	4.00	571.20
AE025680-01	Bellville-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE001759-01	Smith Mountain-ECN103052-140	02/25/2024 - 03/30/2024	8.00	1,142.40
AE017080-01	Portsmouth TM-ECN103052-140	02/25/2024 - 03/30/2024	8.00	1,142.40
AE024950-01	Goshen-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE024976-01	Lancaster TM-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE025456-01	Big Ugly Crk-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
AE025509-01	Catalpa-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
T10096404-002	BluFtRobS1-P19293001-382	02/25/2024 - 03/30/2024	5.00	744.00
R10551244-001	TeaysValleySC-25706-140	02/25/2024 - 03/30/2024	8.00	885.60
K10430733-001	Claytor Hydro P-ITCB14000-140	02/25/2024 - 03/30/2024	2.00	349.80
42744633-02	AshLeslieSt3-P14030104-180	02/25/2024 - 03/30/2024	2.00	285.60
K10556273-001	LEIVASY STATION-WV19CH284-140	02/25/2024 - 03/30/2024	4.00	442.80
T10485934-002	BluefieldJackso-P19047003-150	02/25/2024 - 03/30/2024	13.00	1,758.00
T10519887-002	CharlestonGrand-P20153010-150	02/25/2024 - 03/30/2024	12.00	1,328.40
K10692369-001	MountainViewTs-C24010002-140	02/25/2024 - 03/30/2024	11.00	1,279.80
K10690683-001	Cotton Hill TS-C24010001-140	02/25/2024 - 03/30/2024	11.00	1,279.80
K10692376-001	Oneida Peak TS-C24010003-140	02/25/2024 - 03/30/2024	11.00	1,279.80
K10692753-001	Coal Fork TS-C24010004-140	02/25/2024 - 03/30/2024	10.00	1,107.00
K10692765-001	Bull MountainTS-C24010007-140	02/25/2024 - 03/30/2024	11.00	1,279.80
K10692762-001	DISMAL PEAK TS-C24010005-140	02/25/2024 - 03/30/2024	11.00	1,279.80
K10692764-001	PoorMountainTS-C24010008-140	02/25/2024 - 03/30/2024	9.00	1,058.40
K10692767-001	HighTopTS-C24010006-140	02/25/2024 - 03/30/2024	8.00	885.60
42981370-02	BluArrwhdSt1-P19095001-150	02/25/2024 - 03/30/2024	2.00	285.60
T10181110-002	AshBeaverCrk1-P19036007-180	02/25/2024 - 03/30/2024	11.00	1,600.80
T10368306-002	AshEasternSt2-P17083041-180	02/25/2024 - 03/30/2024	4.00	571.20
42439583-02	AshLeslieSt2-P14030008-180	02/25/2024 - 03/30/2024	4.00	571.20
42596541-02	AshWootonSt2-P14030013-180	02/25/2024 - 03/30/2024	6.00	856.80
42618346-02	AshStinnetSt1-P14030009-110	02/25/2024 - 03/30/2024	2.00	285.60
42657030-02	AshLavttteSt1-P12059014-140	02/25/2024 - 03/30/2024	2.00	285.60
42961458-02	AshHaysBranchS2-P17083031-180	02/25/2024 - 03/30/2024	4.00	571.20
42973737-02	BluSouthAbing1-P19095003-150	02/25/2024 - 03/30/2024	11.00	1,600.80
AE025834-01	Segra2FiberInst-ECN103052-140	02/25/2024 - 03/30/2024	12.00	1,713.60
T10096686-002	BluHillSt2-P19293006-150	02/25/2024 - 03/30/2024	2.00	285.60
T10165877-002	AshOsborneSt1-P19036003-180	02/25/2024 - 03/30/2024	7.00	1,029.60
T10296020-002	AshJackhmnSt2-P18221021-180	02/25/2024 - 03/30/2024	2.00	285.60
T10306068-002	AshlandEastLynn-DR20H1380-140	02/25/2024 - 03/30/2024	1.00	172.80
T10306068-002	AshSoftShellSt3-P17083025-110	02/25/2024 - 03/30/2024	21.00	2,707.80
T10310187-002	BluWildwoodSt1-DP21R02CO-150	02/25/2024 - 03/30/2024	6.00	856.80
T10368297-002	AshGarrettSt2-P17083040-110	02/25/2024 - 03/30/2024	3.00	458.40
T10431857-002	AshSoftShellSt2-P17083044-180	02/25/2024 - 03/30/2024	5.00	744.00
K10436007-001	Leesville Hydro-ITCB21500-215	02/25/2024 - 03/30/2024	2.00	349.80
42955410-02	SouthOhioLakin-P18119001-383	02/25/2024 - 03/30/2024	3.00	279.60
AE024944-01	WindstreamBR-ECN103052-140	02/25/2024 - 03/30/2024	16.00	2,284.80
T10517155-002	CharlestonCarbo-P19161011-383	02/25/2024 - 03/30/2024	7.00	837.00
R10586481-005	JVGMobile-MSTVAUGHN-140	02/25/2024 - 03/30/2024	12.00	1,328.40
R10590346-005	PtPleasantSC-26592-140	02/25/2024 - 03/30/2024	10.00	1,107.00
K10431844-001	Williamson Serv-ITCB14000-140	02/25/2024 - 03/30/2024	4.00	699.60
K10434530-001	Pt Pleasant Off-ITCB14000-140	02/25/2024 - 03/30/2024	2.00	349.80
42825294-02	AshlandCedarCre-P18025009-180	02/25/2024 - 03/30/2024	4.00	442.80
AE025821-01	Bee Mountain-ECN103052-140	02/25/2024 - 03/30/2024	8.00	1,142.40
K10432062-001	Richmond Off -ITCB14000-140	02/25/2024 - 03/30/2024	10.00	1,107.00
AE006857-01	Catalpa TS-ECN103052-110	02/25/2024 - 03/30/2024	2.00	285.60
T10191981-002	Meadow Bri SS-A20076033-383	02/25/2024 - 03/30/2024	2.00	349.80
T10658256-002	Sullivan-P20147001-140	02/25/2024 - 03/30/2024	10.00	1,107.00
42744639-02	KENWOOD EXT-P17076001-140	02/25/2024 - 03/30/2024	6.00	664.20
42800495-02	KP DISTRIBUTION-P17076011-140	02/25/2024 - 03/30/2024	6.00	664.20



ATTN: Trish McCabe / Desiree Canales  
C/O AEP  
850 TECH CENTER DRIVE  
GAHANNA OH 43230

**PLEASE REMIT TO:**  
ACTALENT SERVICES, LLC  
3689 COLLECTION CENTER DRIVE  
CHICAGO IL 60693-0036  
UNITED STATES

**INVOICE**

Invoice No: **EEN00633915A**  
Invoice Date: 4/19/2024  
Payment Terms: **Net 45**  
Release No: 81111215  
Due Date: 6/3/2024

42861331-02	Jsh Fils OPGW-P17081033-150	02/25/2024 - 03/30/2024	2.00	349.80
42841342-02	Kammer345St-A14069055-383	02/25/2024 - 03/30/2024	2.00	349.80
42941397-02	BONSACK STAT-DP18R0280-140	02/25/2024 - 03/30/2024	6.00	664.20
42961461-02	SULLIVAN-P19051004-140	02/25/2024 - 03/30/2024	6.00	664.20
42961462-02	HOLSTON S-P19051003-140	02/25/2024 - 03/30/2024	7.00	837.00
42978719-02	SUL GARD A-P19051016-140	02/25/2024 - 03/30/2024	6.00	664.20
42987463-02	SUL GARD B-P19051017-140	02/25/2024 - 03/30/2024	4.00	442.80
42994260-02	RIGGS EXT-P19051012-140	02/25/2024 - 03/30/2024	6.00	664.20
42994294-01	Grassy Fork Sta-DR19H18A0-140	02/25/2024 - 03/30/2024	2.00	349.80
42998014-02	BONSACK TE-DP18R02C0-140	02/25/2024 - 03/30/2024	6.00	664.20
43010945-02	CAPITOL H 138KV-DR19H07D0-150	02/25/2024 - 03/30/2024	2.00	349.80
AE024801-01	Abingdon TS UB-ECN103052-140	02/25/2024 - 03/30/2024	3.00	458.40
AE025685-01	Schiff Tower-ECN103052-140	02/25/2024 - 03/30/2024	6.00	856.80
E10649842-001	CeredoDresden-CGP000054-140	02/25/2024 - 03/30/2024	5.00	615.60
K10081955-001	Catawba Station-DR19R05A0-140	02/25/2024 - 03/30/2024	2.00	349.80
K10081997-001	Huntington Cour-DR19R05A0-140	02/25/2024 - 03/30/2024	4.00	699.60
T10126229-002	Kenwood T-P17076008-140	02/25/2024 - 03/30/2024	6.00	664.20
T10126331-002	Kenwood S-P17076009-140	02/25/2024 - 03/30/2024	7.00	837.00
T10449810-002	Kenov A-P19066006-140	02/25/2024 - 03/30/2024	1.00	172.80
T10449810-002	Dewey St-P21753002-140	02/25/2024 - 03/30/2024	12.00	1,328.40
T10299847-002	Curry Loo-A21020001-140	02/25/2024 - 03/30/2024	6.00	664.20
T10615935-002	Fort Robin-DR23R15D0-140	02/25/2024 - 03/30/2024	15.00	1,722.60
T10669404-001	Kera Lakes-P23321003-140	02/25/2024 - 03/30/2024	10.00	1,107.00
K10082386-001	Rivermont Stati-DR19R04A0-140	02/25/2024 - 03/30/2024	4.00	699.60
K10094474-001	Stuart Station -DR19R16A0-140	02/25/2024 - 03/30/2024	2.00	349.80
K10283384-001	Poleyard Statio-DR20H03A0-140	02/25/2024 - 03/30/2024	2.00	349.80
K10283390-001	Westlake Statio-DR20R09A0-140	02/25/2024 - 03/30/2024	4.00	699.60
K10314070-001	Wheatland Stati-DR20R01A0-140	02/25/2024 - 03/30/2024	4.00	699.60
K10432172-001	Pennhall Shop-ITC814000-140	02/25/2024 - 03/30/2024	4.00	699.60
K10525012-001	North Beckley -WV22R01A0-140	02/25/2024 - 03/30/2024	4.00	699.60
K10549581-001	FULTON STN-WP22R01A0-210	02/25/2024 - 03/30/2024	4.00	699.60
K10550326-001	OAK HILL STN-WV19CH088-140	02/25/2024 - 03/30/2024	4.00	699.60
K10571247-001	N BECKLEY STN-DR22H08A0-140	02/25/2024 - 03/30/2024	4.00	699.60
K10571266-001	PAD FORK STN-DR21H01A0-140	02/25/2024 - 03/30/2024	4.00	699.60
T10120241-002	Carswl Wilch FC-A21221008-383	02/25/2024 - 03/30/2024	2.00	349.80
T10181084-002	Minnix Mtn SS-A20076008-383	02/25/2024 - 03/30/2024	4.00	699.60
T10181086-002	Mnnx Mtn FCE-A20076009-383	02/25/2024 - 03/30/2024	4.00	699.60
T10181091-002	Sundl Peytna FC-A20076013-383	02/25/2024 - 03/30/2024	4.00	699.60
T10198738-002	DALEWOOD STN-DR20H11B2-140	02/25/2024 - 03/30/2024	3.00	522.60
T10379550-002	CabinCreekTTMP-A25100035-383	02/25/2024 - 03/30/2024	2.00	349.80
T10379553-002	TomsFork TTMP-A25100036-383	02/25/2024 - 03/30/2024	4.00	699.60
T10379608-002	Mabscott TTMP-A25100044-383	02/25/2024 - 03/30/2024	4.00	699.60
T10380175-002	GladeSaltville-A25100054-150	02/25/2024 - 03/30/2024	2.00	349.80
T10401655-002	Polymer TTMP-A25100047-383	02/25/2024 - 03/30/2024	2.00	349.80
T10500855-002	Brues-A22750039-200	02/25/2024 - 03/30/2024	2.00	349.80
AE002693-01	Twin Branch TS-ECN103052-140	02/25/2024 - 03/30/2024	2.00	285.60
AE016358-01	Cols Grove TS-ECN103052-140	02/25/2024 - 03/30/2024	2.00	285.60
42684684-02	AshStinnetSt2-P14030002-180	02/25/2024 - 03/30/2024	4.00	571.20
42744602-02	AshLeslieSt1-P14030102-180	02/25/2024 - 03/30/2024	6.00	856.80
42953971-02	AshHaysBrchSt1-P17083008-180	02/25/2024 - 03/30/2024	8.00	1,142.40
T10282804-002	BluArrwhdStS-A24111002-140	02/25/2024 - 03/30/2024	3.00	458.40
T10604923-002	BluGladeSprg1-A24111005-140	02/25/2024 - 03/30/2024	3.00	458.40
T10506905-002	AshWootonSt1-P14030105-180	02/25/2024 - 03/30/2024	5.00	744.00
			1,796.00	\$ 228,650.20



Account Number  
Invoice Number  
Billing Date  
Due Date

Page 1 of 2  
675019  
June 10, 2024  
July 9, 2024

**TO PAY BY ACH/CREDIT CARD:**

Call 866-838-5079

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

**FOR BILLING QUESTIONS:**

Call our National Client Care Team at 866-838-5079 or email them at [nationalhelp@thryv.com](mailto:nationalhelp@thryv.com)

**Account Summary**

Previous Balance	\$0.00
Current Print Charges	\$289.06
Current Digital Charges	\$0.00
Other Charges and Credits	\$0.00
Total Amount Due	\$289.06

If payment is not received on or before the due date, a late charge will be assessed.

**Important Account Information**

If your invoice has a previous balance this is a friendly reminder. We're here to help. Call 877-503-3996 Opt #3 if you'd like to discuss ways to handle your balance. We value your business and want to work with you. If payment has been sent, please disregard this notice.

Please return this portion with your payment

Correspondence sent to the address on this payment stub will not be read or responded to.

Account Number

**Due Date**

Total Charges Due

**July 9, 2024**

\$289.06

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

*Make checks payable to:*  
Thryv-Berry Network  
Attn: Account Receivable  
P.O. Box 207184  
Dallas, TX 75320-7184

CANADIAN ADVERTISING IS BILLED IN US CURRENCY; WE ACCEPT PAYMENTS IN CANADIAN CURRENCY HOWEVER; THE FUNDS WILL BE CONVERTED TO US EQUIVALENT.

ARQIH0AP



Account Number  
Invoice Number  
Billing Date  
Due Date

675019  
June 10, 2024  
July 9, 2024

**Current Print Charges**

AEP-KENTUCKY POWER CO 000300

Directory Name	Directory Number	Directory Duration	Life	Install	Amount Due
* KY Staffordsville ILEC	29910	5/2024 To 05/2025	12R	1 of 1	\$289.06

**Total Current Print charges** **\$289.06**

**Current Digital Charges**

No Current Digital Charges.

**Total Current Digital Charges** **\$ .00**

\* indicates new charge

**Other Charges and Credits**

No Other Charges and Credits.

**Total Other Charges and Credits** **\$ .00**

**Payments Received Since Last Bill**

Check Number	Invoice Number	Date Received	Amount
	671261	05/17/2024	\$1,641.24

**Total Payments Received** **\$1,641.24**



Vendor Ref #	Work Order	Sum of Amount
0524ER80294352	AE02474601	\$ 372.60
0524ER80294352	T10736548001	\$ 1,117.80
0524ER80294352	T10744833001	\$ 248.40
0524ER80294352	TL0041178001	\$ 372.60
0524ER80294352	TL0041393001	\$ 496.80
0524ER80294352	TL0045994001	\$ 1,117.80
0524ER80294352	TL0047356001	\$ 372.60
0524ER80294352	TL0047361001	\$ 372.60
0524ER80294352	TL0047378001	\$ 372.60
0524ER80294352	TL0047446001	\$ 372.60
0524ER80294352	TL0070742001	\$ 248.40
0524ER80294352	TL0071014001	\$ 372.60
0524ER80294352	TL0071015001	\$ 248.40
0524ER80294352	TL0071019001	\$ 372.60
0524ER80294352	TL0071200001	\$ 496.80
0524ER80294352	TL0071201001	\$ 621.00
0524ER80294352	TL0071203001	\$ 372.60
0524ER80294352	TL0071474001	\$ 372.60
0524ER80294352	TL0072503001	\$ 1,242.00
0524ER80294352	TL0072656001	\$ 1,117.80
0524ER80294352	TL0072714001	\$ 372.60
0524ER80294352	TL0072739001	\$ 496.80





[illegible]



# Invoice

CAA Invoice No. 118023

## Invoice No. 118023

Purchase Order Number	Vendor Invoice Number	Invoiced Date
80294352	0524ER80294352	2024-09-26
Invoice Start Date	Invoice End Date	
2024-04-28	2024-05-25	
Business Unit	Vendor Contact Name	Contact Telephone Number
TRANSMISSION	ACTALENT SERVICES LLC	
Remit To Address	Invoice Verifier	
3689 COLLECTIONS CENTER DR, CHICAGO, IL, 60693-0036, USA	Jordan N. Ambrose	

### Timesheets

Timesheet number	Start Date	End Date	Timesheet Approver	Reviewer Comments	Comments
101202	2024-04-28	2024-05-25			0524ER80294352

### Activities

Activity Number	Activity Description	Labor Hours	Equipment Hours	Total Lumpsum	Reimbursable Quantity	Uptask Quantity	Cu	Amount
80294352.4.004	Actalent - 80294352 - David Mays Jr. - Lead ROW Agent	93	0	0	0	0	\$0.00	\$11,550.60
Grand Total		93	0	0	0	0	\$0.00	\$11,550.60

### Accounting Information

GL/BU	Project BU	Project	WorkOrder	Account	Dept ID	Cost Component	Activity	Amount
103	TRANS	ETNANDA	SP00362001	1070000	10425	210	691	\$11,550.60

### Labor rates

Code	Name	Type	Rate	Hours	Units	Amount
CAA-ROWAGENTLEAD		regLaborHours	\$124.20	93	0	\$11,550.60
Total Amount						\$11,550.60



Account Number  
Invoice Number  
Billing Date  
Due Date

Page 1 of 2

683703

February 10, 2025

March 9, 2025

**TO PAY BY ACH/CREDIT CARD:**

Call 866-838-5079

**FOR BILLING QUESTIONS:**

Call our National Client Care Team at 866-838-5079 or email them at [nationalhelp@thryv.com](mailto:nationalhelp@thryv.com)

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

**Account Summary**

Previous Balance	\$ .00
Current Print Charges	\$602.37
Current Digital Charges	\$ .00
Other Charges and Credits	\$ .00
Total Amount Due	\$602.37

If payment is not received on or before the due date, a late charge will be assessed.

**Important Account Information**

If your invoice has a previous balance this is a friendly reminder. We're here to help. Call 877-503-3996 Opt #3 if you'd like to discuss ways to handle your balance. We value your business and want to work with you. If payment has been sent, please disregard this notice.

Please return this portion with your payment

Correspondence sent to the address on this payment stub will not be read or responded to.

Account Number

**Due Date**

Total Charges Due

**March 9, 2025**

\$602.37

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

*Make checks payable to:*  
Thryv-BNI  
ATTN: Accounts Receivable  
P.O. Box 646301  
Dallas, TX 75264-6301

CANADIAN ADVERTISING IS BILLED IN US CURRENCY; WE ACCEPT PAYMENTS IN CANADIAN CURRENCY HOWEVER; THE FUNDS WILL BE CONVERTED TO US EQUIVALENT.

ARQIH0AP



Account Number  
Invoice Number  
Billing Date  
Due Date

683703  
February 10, 2025  
March 9, 2025

#### Current Print Charges

AEP-KENTUCKY POWER CO 000300

Directory Name	Directory Number	Directory Duration	Life	Install	Amount Due
* KY Nicholasvll Ar ILEC	103371	1/2025 To 07/2026	18R	1 of 1	\$602.37

**Total Current Print charges** **\$602.37**

#### Current Digital Charges

No Current Digital Charges.

**Total Current Digital Charges** **\$ .00**

\* indicates new charge

#### Other Charges and Credits

No Other Charges and Credits.

**Total Other Charges and Credits** **\$ .00**

#### Payments Received Since Last Bill

Check Number	Invoice Number	Date Received	Amount
No payment received since last bill			

**Total Payments Received** **\$ .00**



CORPORATE ID : 36-2467635

P.O Box 619810  
DFW Airport, Tx 75261-9810

Account Number

Invoice Number

Billing Date

Due Date

Page 1 of 2

680587

November 10, 2024

December 9, 2024

**TO PAY BY ACH/CREDIT CARD:**

Call 866-838-5079

**FOR BILLING QUESTIONS:**

Call our National Client Care Team at 866-838-5079 or email them at [nationalhelp@thryv.com](mailto:nationalhelp@thryv.com)

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

**Account Summary**

Previous Balance	\$ .00
Current Print Charges	\$744.96
Current Digital Charges	\$ .00
Other Charges and Credits	\$ .00
Total Amount Due	\$744.96

If payment is not received on or before the due date, a late charge will be assessed.

**Important Account Information**

If your invoice has a previous balance this is a friendly reminder. We're here to help. Call 877-503-3996 Opt #3 if you'd like to discuss ways to handle your balance. We value your business and want to work with you. If payment has been sent, please disregard this notice.

Please return this portion with your payment

Correspondence sent to the address on this payment stub will not be read or responded to.

Account Number

**Due Date**

Total Charges Due

**December 9, 2024**

\$744.96

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

*Make checks payable to:*  
Thryv-Berry Network  
Attn: Account Receivable  
P.O. Box 207184  
Dallas, TX 75320-7184

CANADIAN ADVERTISING IS BILLED IN US CURRENCY; WE ACCEPT PAYMENTS IN CANADIAN CURRENCY HOWEVER; THE FUNDS WILL BE CONVERTED TO US EQUIVALENT.

ARQIH0AP



Account Number  
Invoice Number  
Billing Date  
Due Date

Page 2 of 2  
0123-0017  
680587  
November 10, 2024  
December 9, 2024

**Current Print Charges**

AEP-KENTUCKY POWER CO 000300

Directory Name	Directory Number	Directory Duration	Life	Install	Amount Due
* KY Harold ILEC	29377	10/2024 To 10/2025	12R	1 of 1	\$277.42
* KY West Liberty ILEC	29979	10/2024 To 10/2025	12R	1 of 1	\$467.54
<b>Total Current Print charges</b>					<b>\$744.96</b>

**Current Digital Charges**

No Current Digital Charges.

**Total Current Digital Charges** **\$ .00**

\* indicates new charge

**Other Charges and Credits**

No Other Charges and Credits.

**Total Other Charges and Credits** **\$ .00**

**Payments Received Since Last Bill**

Check Number	Invoice Number	Date Received	Amount
	679497	10/17/2024	\$194.97
<b>Total Payments Received</b>			<b>\$194.97</b>



ATTN: Trish McCabe / Desiree Canales  
C/O AEP  
850 TECH CENTER DRIVE  
GAHANNA OH 43230

PLEASE REMIT TO:  
ACTALENT SERVICES, LLC  
3689 COLLECTION CENTER DRIVE  
CHICAGO IL 60693-0036  
UNITED STATES

## INVOICE

Invoice No:  
Invoice Date:  
Payment Terms:  
Release No:  
Due Date:

EEN00646370A  
5/17/2024  
Net 45  
81111215  
7/1/2024

Contract #: 027996640000X103 - IT Telecom  
Reviewer: ATTN: Trish McCabe / Desiree Canales  
Approver: SUNITA MODAK  
Activity/ Location: GA Proj Managers ITT-8 (APCO)

For Billing Inquiries contact Ndendet, Flore at: [ndendet@actalent.com](mailto:ndendet@actalent.com)

Total Amount	\$179,932.20
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Work Order	Description	Date Period	Sum of Quantity	Sum of Amount
42973737-02	BluSouthAbing1-P19095003-150	03/31/2024 - 04/27/2024	8.00	1,142.40
T10096686-002	BluHillSt2-P19293006-150	03/31/2024 - 04/27/2024	4.00	571.20
T10174216-002	ForestSta TTMP-A20075030-140	03/31/2024 - 04/27/2024	2.00	349.80
K10430723-001	Smith Mt. Hydro-ITCB21500-215	03/31/2024 - 04/27/2024	8.00	885.60
K10432062-001	Richmond Off -ITCB14000-140	03/31/2024 - 04/27/2024	5.00	744.00
K10442752-001	Byllesby Hydro -ITCB21500-215	03/31/2024 - 04/27/2024	3.00	522.60
K10434404-001	Abingdon Trans -ITCB15000-150	03/31/2024 - 04/27/2024	3.00	522.60
R10590346-005	PtPleasantSC-26592-140	03/31/2024 - 04/27/2024	12.00	1,328.40
42744639-02	KENWOOD EXT-P17076001-140	03/31/2024 - 04/27/2024	10.00	1,107.00
42800495-02	KP DISTRIBUTION-P17076011-140	03/31/2024 - 04/27/2024	10.00	1,107.00
42902193-02	Rvr Glad OPGW-P17081042-150	03/31/2024 - 04/27/2024	2.00	349.80
42861321-02	Rvr Glad 136kv-P17081029-150	03/31/2024 - 04/27/2024	2.00	349.80
42904913-01	WPS Teays val-25706-140	03/31/2024 - 04/27/2024	3.00	394.20
42941397-02	BONSACK STAT-DP18R0280-140	03/31/2024 - 04/27/2024	8.00	885.60
42905285-02	CharlestonSheri-P12059029-383	03/31/2024 - 04/27/2024	4.00	442.80
42956049-02	Fld Dn Rvr-P19014001-150	03/31/2024 - 04/27/2024	3.00	522.60
42956588-02	CharlestonNitro-P18255001-383	03/31/2024 - 04/27/2024	4.00	442.80
42961461-02	SULLIVAN-P19051004-140	03/31/2024 - 04/27/2024	10.00	1,107.00
42961462-02	HOLSTON S-P19051003-140	03/31/2024 - 04/27/2024	13.00	1,501.20
42965341-02	CharlestonBelle-P18039005-383	03/31/2024 - 04/27/2024	4.00	442.80
42978719-02	SUL GARD A-P19051016-140	03/31/2024 - 04/27/2024	6.00	664.20
42980152-02	BlufieldJubalEa-A16922008-150	03/31/2024 - 04/27/2024	4.00	571.20
42983620-02	BluefieldSourwo-P19070001-383	03/31/2024 - 04/27/2024	13.00	1,758.00
42987463-02	SUL GARD B-P19051017-140	03/31/2024 - 04/27/2024	6.00	664.20
42994260-02	RIGGS EXT-P19051012-140	03/31/2024 - 04/27/2024	6.00	664.20
42998014-02	BONSACK TE-DP18R02C0-140	03/31/2024 - 04/27/2024	8.00	885.60
43010000-02	AshlandJackhorn-P18221014-180	03/31/2024 - 04/27/2024	10.00	1,299.60
43016577-02	N POINTE STN-DR19H0580-140	03/31/2024 - 04/27/2024	2.00	349.80
43017795-02	Burlington Hgts-DR19R0580-140	03/31/2024 - 04/27/2024	3.00	522.60
43018223-02	CharlestonJarre-P17026007-383	03/31/2024 - 04/27/2024	4.00	442.80
AE000877-01	Greenup TS ABD-ECN103052-110	03/31/2024 - 04/27/2024	6.00	856.80
AE006857-01	Catalpa TS-ECN103052-110	03/31/2024 - 04/27/2024	6.00	856.80
AE024241-01	DingessWV-ECN103052-140	03/31/2024 - 04/27/2024	6.00	856.80
AE024241-01	Dingess TS-ECN103052-140	03/31/2024 - 04/27/2024	4.00	571.20
AE024647-01	Burning Rock NS-ECN103052-140	03/31/2024 - 04/27/2024	6.00	856.80
AE024647-01	Burning Rock TS-EDN102170-140	03/31/2024 - 04/27/2024	3.00	458.40
AE024801-01	Abingdon TS UB-ECN103052-140	03/31/2024 - 04/27/2024	7.00	1,029.60
AE024816-01	Dingess TS-ECN103052-140	03/31/2024 - 04/27/2024	2.00	285.60
AE024944-01	WindstreamBR-ECN103052-140	03/31/2024 - 04/27/2024	16.00	2,284.80
AE025685-01	Schiff Tower-ECN103052-140	03/31/2024 - 04/27/2024	8.00	1,142.40
AE025821-01	Bee Mountain-ECN103052-140	03/31/2024 - 04/27/2024	8.00	1,142.40
E10649842-001	CeredoDresden-CGP000054-140	03/31/2024 - 04/27/2024	12.00	1,328.40
K10058706-001	Ragland Station-DR19H16A0-140	03/31/2024 - 04/27/2024	2.00	349.80
K10054505-001	Hopkins Station-DR19H18A0-140	03/31/2024 - 04/27/2024	3.00	522.60
K10081972-001	Cloverdale 138K-DR19R05A0-140	03/31/2024 - 04/27/2024	5.00	872.40
K10081996-001	Fieldale Statio-DR19R19A0-140	03/31/2024 - 04/27/2024	5.00	872.40
K10082135-001	Peakland Statio-DR19R04A0-140	03/31/2024 - 04/27/2024	3.00	522.60
K10082003-001	Logan Station 3-DR19H03A0-140	03/31/2024 - 04/27/2024	3.00	522.60
K10082005-001	Martinsville St-DR19R25A0-140	03/31/2024 - 04/27/2024	3.00	522.60
T10092112-002	KincaidSTSuper-P19268001-383	03/31/2024 - 04/27/2024	4.00	442.80
T10118158-002	TomsStation-P19268007-383	03/31/2024 - 04/27/2024	4.00	442.80
T10126229-002	Kenwood T-P17076008-140	03/31/2024 - 04/27/2024	6.00	664.20
T10126331-002	Kenwood S-P17076009-140	03/31/2024 - 04/27/2024	7.00	837.00
T10299847-002	Curry Loo-A21020001-140	03/31/2024 - 04/27/2024	6.00	664.20
T10321955-002	AppleGroveSuper-P19302001-383	03/31/2024 - 04/27/2024	4.00	442.80
T10449810-002	Dewey St-P21753002-140	03/31/2024 - 04/27/2024	6.00	664.20
T10466777-002	Wharnccliffe-P22012048-383	03/31/2024 - 04/27/2024	4.00	442.80
T10658256-002	Sullivan-P20147001-140	03/31/2024 - 04/27/2024	8.00	1,014.00
T10615935-002	Fort Robin-DR23R15D0-140	03/31/2024 - 04/27/2024	6.00	664.20
T10669404-001	Kera Lakes-P23321003-140	03/31/2024 - 04/27/2024	6.00	664.20
K10284564-001	AFL KYTR REMED-ECNMTP01-384	03/31/2024 - 04/27/2024	32.00	4,056.00
K10289664-001	AFL APCO REMED-ECNMTP01-140	03/31/2024 - 04/27/2024	42.00	5,321.40
K10360186-001	RBB Logan POP-ITCT14022-140	03/31/2024 - 04/27/2024	11.00	1,600.80
K10430772-001	Wheeling SC-ITCB21000-210	03/31/2024 - 04/27/2024	6.00	664.20
K10362198-001	Logan Cty-ITCT14022-140	03/31/2024 - 04/27/2024	6.00	856.80
K10433119-001	Fieldale OFC -ITCB14000-140	03/31/2024 - 04/27/2024	2.00	349.80
K10432085-001	Grundy Off-ITCB14000-140	03/31/2024 - 04/27/2024	8.00	1,014.00
K10432117-001	Kenova Telecom -ITCB14000-140	03/31/2024 - 04/27/2024	3.00	522.60
K10432163-001	Bluefield SC-ITCB14000-140	03/31/2024 - 04/27/2024	7.00	965.40





ATTN: Trish McCabe / Desiree Canales  
C/O AEP  
850 TECH CENTER DRIVE  
GAHANNA OH 43230

PLEASE REMIT TO:  
ACTALENT SERVICES, LLC  
3689 COLLECTION CENTER DRIVE  
CHICAGO IL 60693-0036  
UNITED STATES

INVOICE

Invoice No:  
Invoice Date:  
Payment Terms:  
Release No:  
Due Date:

EEN00646370A  
5/17/2024  
Net 45  
81111215  
7/1/2024

K10435897-001	Pulaski SC-ITCB14000-140	03/31/2024 - 04/27/2024	3.00	522.60
K10435994-001	Roanoke Ofc -ITCB14000-140	03/31/2024 - 04/27/2024	6.00	664.20
K10435998-001	Roanoke SC-ITCB14000-140	03/31/2024 - 04/27/2024	6.00	664.20
K10436001-001	Rocky Mount Ofc-ITCB14000-140	03/31/2024 - 04/27/2024	9.00	1,186.80
K10437219-001	Huntington Serv-ITCB14000-140	03/31/2024 - 04/27/2024	3.00	522.60
K10437642-001	Dresden PS-ITCB21500-215	03/31/2024 - 04/27/2024	3.00	522.60
K10437674-001	Pineville OFC-ITCB14000-140	03/31/2024 - 04/27/2024	3.00	522.60
K10445597-001	Washing DC Off -ITCB10300-103	03/31/2024 - 04/27/2024	3.00	522.60
K10482178-001	RBB DEHUE CES-ITCT14022-140	03/31/2024 - 04/27/2024	9.00	1,186.80
K10486869-001	RBB MUDFORK CES-ITCT14022-140	03/31/2024 - 04/27/2024	6.00	664.20
K10486875-001	RBB HEWETT CES-ITCT14022-140	03/31/2024 - 04/27/2024	4.00	571.20
K10486882-001	RBB HUFFCR CES-ITCT14022-140	03/31/2024 - 04/27/2024	4.00	442.80
K10486886-001	RBB HURRI CES-ITCT14022-140	03/31/2024 - 04/27/2024	7.00	965.40
K10486890-001	RBB MIDKIFF CES-ITCT14022-140	03/31/2024 - 04/27/2024	2.00	221.40
K10486893-001	RBB NPOINT CES-ITCT14022-140	03/31/2024 - 04/27/2024	3.00	522.60
K10486906-001	RBB SHARPLES ST-ITCT14022-140	03/31/2024 - 04/27/2024	7.00	965.40
K10486973-001	RBB SPRIGG STA-ITCT14022-140	03/31/2024 - 04/27/2024	7.00	965.40
K10486979-001	RBB DINGESS ST-ITCT14022-140	03/31/2024 - 04/27/2024	5.00	744.00
K10488564-001	RBB BORDER ST-ITCT14022-140	03/31/2024 - 04/27/2024	2.00	221.40
K10488583-001	RBB STONEBR ST-ITCT14022-140	03/31/2024 - 04/27/2024	9.00	1,315.20
K10489114-001	RBB LATROBE ST-ITCT14022-140	03/31/2024 - 04/27/2024	2.00	221.40
K10561254-001	Stone Branch-ITCT14022-140	03/31/2024 - 04/27/2024	19.00	2,293.80
K10561262-001	Chauncey-ITCT14022-140	03/31/2024 - 04/27/2024	23.00	2,929.20
K10561575-001	Dingess -ITCT14022-140	03/31/2024 - 04/27/2024	10.00	1,363.80
K10561575-001	Dingess-ITCT14022-140	03/31/2024 - 04/27/2024	8.00	885.60
K10561408-001	Hewett Sharp-ITCT14022-140	03/31/2024 - 04/27/2024	21.00	2,643.60
K10561586-001	Smokehouse-ITCT14022-140	03/31/2024 - 04/27/2024	22.00	2,820.60
K10561591-001	Cow Creek-ITCT14022-140	03/31/2024 - 04/27/2024	21.00	2,772.00
K10561587-001	Dehue Huff-ITCT14022-140	03/31/2024 - 04/27/2024	21.00	2,707.80
K1056462-001	Beckley Station-DR22H08A0-140	03/31/2024 - 04/27/2024	3.00	522.60
K10567233-001	Marrowbone-ITCT14022-140	03/31/2024 - 04/27/2024	25.00	3,214.80
K10567263-001	Musick -ITCT14022-140	03/31/2024 - 04/27/2024	15.00	2,107.80
K10567263-001	Musick-ITCT14022-140	03/31/2024 - 04/27/2024	8.00	885.60
K10567258-001	Myrtle -ITCT14022-140	03/31/2024 - 04/27/2024	15.00	2,107.80
K10567258-001	Myrtle-ITCT14022-140	03/31/2024 - 04/27/2024	10.00	1,107.00
K10567267-001	Sprigg-ITCT14022-140	03/31/2024 - 04/27/2024	20.00	2,470.80
K10567265-001	Naugatuck-ITCT14022-140	03/31/2024 - 04/27/2024	22.00	2,692.20
K10567284-001	Vulcan WV-ITCT14022-140	03/31/2024 - 04/27/2024	20.00	2,470.80
K10567291-001	Vulcan KY -ITCT14022-140	03/31/2024 - 04/27/2024	10.00	1,363.80
K10567291-001	Vulcan KY-ITCT14022-140	03/31/2024 - 04/27/2024	10.00	1,107.00
K10567477-001	Mohawk-ITCT14022-140	03/31/2024 - 04/27/2024	24.00	3,042.00
K10567339-001	Breeden Marr-ITCT14022-140	03/31/2024 - 04/27/2024	25.00	3,214.80
K10567345-001	Mountain View-ITCT14022-140	03/31/2024 - 04/27/2024	23.00	2,865.00
K10572745-001	RBBGRAYSON SP-ITCT14019-140	03/31/2024 - 04/27/2024	3.00	522.60
K10572760-001	RBBGRAYDISTPOL-ITCT14019-140	03/31/2024 - 04/27/2024	3.00	522.60
K10620830-001	Logan Splicing -ITCT14022-140	03/31/2024 - 04/27/2024	15.00	1,979.40
K10665276-001	Existing Miles-ITCT14022-140	03/31/2024 - 04/27/2024	16.00	1,963.80
K10620838-001	Mingo Splicing -ITCT14022-140	03/31/2024 - 04/27/2024	17.00	2,136.60
R10345765-001	Roanoke RDC-26436-150	03/31/2024 - 04/27/2024	10.00	1,107.00
T10024273-002	CharlestonHerns-P19205005-383	03/31/2024 - 04/27/2024	4.00	442.80
T10049054-002	CharlestonKinca-P19073015-383	03/31/2024 - 04/27/2024	4.00	442.80
T10086571-002	CharlestonKenna-DP19H05Y0-383	03/31/2024 - 04/27/2024	9.00	1,315.20
T10096795-002	BluefieldFortRo-P19293008-150	03/31/2024 - 04/27/2024	6.00	856.80
T10154958-002	BluefieldHockma-DP20H03C1-150	03/31/2024 - 04/27/2024	12.00	1,585.20
T10165851-002	AshlandOsborn-P19036009-180	03/31/2024 - 04/27/2024	10.00	1,299.60
T10172940-002	Vint Med St FCE-A20075001-150	03/31/2024 - 04/27/2024	2.00	349.80
T10174201-002	RoankEI Stl FC-A20075027-150	03/31/2024 - 04/27/2024	3.00	522.60
T10284547-002	Mount Nebo-A24111023-383	03/31/2024 - 04/27/2024	2.00	349.80
T10317109-002	BluefieldGarden-P19058014-383	03/31/2024 - 04/27/2024	2.00	285.60
T10311720-002	CharlestonHopki-A16803026-383	03/31/2024 - 04/27/2024	7.00	965.40
T10317119-002	BluefieldPadfor-P19058016-383	03/31/2024 - 04/27/2024	4.00	571.20
T10319111-002	CharlestonCrary-P18253020-383	03/31/2024 - 04/27/2024	4.00	442.80
T10379548-002	Ambler Jarrett-A25100033-383	03/31/2024 - 04/27/2024	3.00	522.60
T10379606-002	KenovaTBlgTTMP-A25100040-383	03/31/2024 - 04/27/2024	3.00	522.60
T10380181-002	OakBassettTTMP-A25100055-150	03/31/2024 - 04/27/2024	3.00	522.60
T10383950-002	AshlandBakerFB-A14068001-180	03/31/2024 - 04/27/2024	3.00	522.60
T10464252-002	Benwood-A22750029-210	03/31/2024 - 04/27/2024	2.00	349.80
T10402067-002	Shoals TrlState-A25100065-383	03/31/2024 - 04/27/2024	3.00	522.60
T10448194-002	Clf Jms Rvr Fbr-P17081051-150	03/31/2024 - 04/27/2024	4.00	442.80
T10465202-002	CharlestonAirpo-DP21H05C5-150	03/31/2024 - 04/27/2024	4.00	442.80
T10496350-002	BluefieldArrowh-P19095026-150	03/31/2024 - 04/27/2024	10.00	1,299.60
T10485934-002	BluefieldJacko-P19047003-150	03/31/2024 - 04/27/2024	7.00	1,093.80
T10519887-002	CharlestonGrand-P20153010-150	03/31/2024 - 04/27/2024	2.00	349.80
Z10543675-001	APCO FAMI-ITCT10304-1060	03/31/2024 - 04/27/2024	15.00	2,142.00
AE001759-01	Smith Mountain-ECN103052-140	03/31/2024 - 04/27/2024	6.00	856.80
AE002693-01	Twin Branch TS-ECN103052-140	03/31/2024 - 04/27/2024	2.00	285.60
AE009303-01	Lavalette-ECN103052-140	03/31/2024 - 04/27/2024	6.00	856.80
AE016358-01	Colo Grove TS-ECN103052-140	03/31/2024 - 04/27/2024	2.00	285.60
AE017080-01	Portsmouth TM-ECN103052-140	03/31/2024 - 04/27/2024	9.00	1,315.20
AE024950-01	Goshen-ECN103052-140	03/31/2024 - 04/27/2024	8.00	1,142.40
AE024976-01	Lancaster TM-ECN103052-140	03/31/2024 - 04/27/2024	6.00	856.80
AE025116-01	Blue Creek TM-ECN103052-140	03/31/2024 - 04/27/2024	8.00	1,142.40
AE025289-01	Newcomertown-ECN103052-140	03/31/2024 - 04/27/2024	7.00	1,029.60
AE025456-01	Big Ugly Crk-ECN103052-140	03/31/2024 - 04/27/2024	2.00	285.60
AE025484-01	New Buffalo-ECN103052-140	03/31/2024 - 04/27/2024	9.00	1,315.20
AE025675-01	Salineville-ECN103052-140	03/31/2024 - 04/27/2024	6.00	856.80
AE025680-01	Belville-ECN103052-140	03/31/2024 - 04/27/2024	6.00	856.80
K10690683-001	Cotton Hill TS-C24010001-140	03/31/2024 - 04/27/2024	9.00	1,058.40



ATTN: Trish McCabe / Desiree Canales  
C/O AEP  
850 TECH CENTER DRIVE  
GAHANNA OH 43230

**PLEASE REMIT TO:**  
ACTALENT SERVICES, LLC  
3689 COLLECTION CENTER DRIVE  
CHICAGO IL 60693-0036  
UNITED STATES

**INVOICE**

Invoice No:  
Invoice Date:  
Payment Terms:  
Release No:  
Due Date:

**EEN00646370A**  
5/17/2024  
**Net 45**  
81111215  
7/1/2024

K10692369-001	MountainViewTS-C24010002-140	03/31/2024 - 04/27/2024	9.00	1,058.40
K10692376-001	Oneida Peak TS-C24010003-140	03/31/2024 - 04/27/2024	6.00	664.20
K10692753-001	Coal Fork TS-C24010004-140	03/31/2024 - 04/27/2024	6.00	664.20
K10692764-001	PoorMountainTS-C24010008-140	03/31/2024 - 04/27/2024	8.00	885.60
K10692762-001	Dismal Peak TS-C24010005-140	03/31/2024 - 04/27/2024	8.00	885.60
K10692765-001	Bull MountainTS-C24010007-140	03/31/2024 - 04/27/2024	4.00	442.80
R10551244-001	TeaysValleySC-25706-140	03/31/2024 - 04/27/2024	6.00	664.20
R10586481-005	JVGMobile-MSTVAUGHN-140	03/31/2024 - 04/27/2024	8.00	885.60
42439583-02	AshLeslieSt2-P14030008-180	03/31/2024 - 04/27/2024	8.00	1,014.00
42596541-02	AshWootonSt2-P14030013-180	03/31/2024 - 04/27/2024	8.00	1,014.00
42684684-02	AshStinnetSt2-P14030002-180	03/31/2024 - 04/27/2024	2.00	285.60
42744613-02	AshStinnetSt3-P14030103-180	03/31/2024 - 04/27/2024	2.00	285.60
42744633-02	AshLeslieSt3-P14030104-180	03/31/2024 - 04/27/2024	2.00	285.60
42953971-02	AshHaysBrchSt1-P17083008-180	03/31/2024 - 04/27/2024	2.00	285.60
42956506-02	AshSoftShellSt1-P17083001-180	03/31/2024 - 04/27/2024	4.00	571.20
42956579-02	AshGarrettSt1-P17083006-180	03/31/2024 - 04/27/2024	4.00	571.20
42961458-02	AshHaysBranchS2-P17083031-180	03/31/2024 - 04/27/2024	2.00	285.60
42981370-02	BluArrwhdSt1-P19095001-150	03/31/2024 - 04/27/2024	2.00	285.60
T10096404-002	BluFtRobS1-P19293001-382	03/31/2024 - 04/27/2024	2.00	285.60
T10096479-002	BluMoccsinGap1-P19293002-150	03/31/2024 - 04/27/2024	2.00	285.60
T10127103-002	BluFtRobS4-P19293011-260	03/31/2024 - 04/27/2024	2.00	285.60
T10165877-002	AshOsborneSt1-P19036003-180	03/31/2024 - 04/27/2024	4.00	571.20
T10181110-002	AshBeaverCrk1-P19036007-180	03/31/2024 - 04/27/2024	4.00	571.20
T10186427-002	AshNewCampSt1-P19305022-110	03/31/2024 - 04/27/2024	6.00	856.80
T10282804-002	BluArrwhdSt5-A24111002-140	03/31/2024 - 04/27/2024	2.00	285.60
T10284026-002	BluMeadowSt1-A24111007-150	03/31/2024 - 04/27/2024	2.00	285.60
T10305744-002	AshAllenSt2-P19092023-110	03/31/2024 - 04/27/2024	2.00	285.60
T10296020-002	AshJackhrrnSt2-P18221021-180	03/31/2024 - 04/27/2024	4.00	571.20
T10310187-002	BluWildwoodSt1-DP21R02C0-150	03/31/2024 - 04/27/2024	6.00	856.80
T10368297-002	AshGarrettSt2-P17083040-110	03/31/2024 - 04/27/2024	3.00	458.40
T10368306-002	AshEasternSt2-P17083041-180	03/31/2024 - 04/27/2024	4.00	571.20
T10431854-002	AshEasternSt1-P17083043-180	03/31/2024 - 04/27/2024	2.00	285.60
T10431857-002	AshSoftShellSt2-P17083044-180	03/31/2024 - 04/27/2024	3.00	458.40
T10506905-002	AshWootonSt1-P14030105-180	03/31/2024 - 04/27/2024	2.00	285.60
T10506918-002	AshLeslieSt4-P14030106-180	03/31/2024 - 04/27/2024	5.00	744.00
			1,368.00	\$ 179,932.20



Current Lighting Solutions, LLC  
25825 Science Park Drive  
Beachwood, Oh 44122

CUSTOMER INVOICE 438514759  
ORIGINAL Page 1 of 2

DOCUMENT INFO:	
Invoice Number/Date:	438514759 / 02/25/2025
Order Number/Date:	120940446 / 01/29/2025
PO Number/Date:	81566288
Due Date:	02/15/0001
Division:	Roadway
Payer ID:	331999
Payer Name:	AMERICAN ELECTRIC POWER CO INC

<b>SOLD TO:</b> 331999	<b>ID:</b>
AMERICAN ELECTRIC POWER CO INC 1 RIVERSIDE PLAZA COLUMBUS OH 43215 USA	

Agency/Rep:
ELUS CO - OH
ELUS CO - OH
ELUS CO - OH

<b>BILL TO:</b> 331999
AMERICAN ELECTRIC POWER CO INC 1 RIVERSIDE PLAZA COLUMBUS OH 43215 USA

<b>SHIP TO:</b> 331999
AEP Ashland 12333 KEVIN AVE ASHLAND KY 41102-8653 USA

<b>REMIT TO:</b> 402084
<div></div> <div>Current Lighting Solutions, LLC Bank Of America - Atlanta 6000 Feldwood Rd PO Box 402084 Atlanta GA 30384-2084 USA</div>

EIN Number: 83-3011687
Currency: USD

SHIPPING INFO:	
Shipping Doc/Date:	840983967 / 02/25/2025
Delivery Terms:	Free on board
Point of Delivery:	Shipping Point
Shipping Point:	Hendersonville LS Plant-Zero D
Carrier:	XPO LOGISTICS FREIGHT, INC.
BOL/Tracking:	259-321856
Number of Shipping Units:	174
Gross Weight:	1370.163 LB
Net Weight:	1170.063 LB

Payment Terms: Net 45 days

Special Markings/Instructions:

\*\*SPECIAL PACK REQUIREMENTS FOR AMERICAN ELECTRIC POWER\*\*

- 1) APPLY ADDRESS LABELS TO ALL 4 SIDES OF PALLET
- 2) APPLY CORNER POSTS TO EVERY PALLET\_ PART# 35-212095-24
- 3) MAX PALLET HEIGHT IS 48"
- 4) NO MIXED PALLETS
- 5) PALLET LABEL MUST INCLUDE CUSTOMER'S PART# 81566288

Material Number / Catalog Number		Brand		Qty Ordered		Qty Backordered		Qty Shipped		Price UM		Price UM		Value	
Item	Description / Additional Information	Order date		Delivery note/Item		Carrier + tracking nr.									
1	ERL1	ERL1015C540AWHTELR		EVOL		87 EA		192.80		EA		16,773.60			



Current Lighting Solutions, LLC  
25825 Science Park Drive  
Beachwood, Oh 44122

CUSTOMER INVOICE 438514759  
ORIGINAL Page 2 of 2

02/26/2025 PO Number: 81566288

Item	Material Number / Catalog Number Description / Additional Information	Order date	Brand	Qty		Backordered	Qty		Price	UM	Value
				Ordered	Delivery note/Item		Shipped	UM			
Carrier + tracking nr.											
Harmonized Code:9405426000											
2	73251	01/29/2025	EVOL	0840983967/000010			87	EA	10.38	EA	903.06
	SCCL-PECTL										
	UPC Code: 00662050066049										
Harmonized Code:8536698000											
				01/29/2025	0840983967/000020	XPO LOGISTICS FREIGHT, INC. + 0033369709					

Merchandise Total						17,676.66
Invoice Amount						17,676.66

Additional Comments:  
Note:

Broadway Electric Service Comp  
P O BOX 3250  
Knoxville, TN 37927  
865 524-1851



## Invoice 114524K

Bill to: AEP - Columbus, OH 1 Riverside Plaza Columbus, OH 43215	Job: 4693 AEP FC Dave Williamson 404 29TH STREET WEST CHARLESTON, WV 25387
---------------------------------------------------------------------------	-------------------------------------------------------------------------------------

Invoice #: 114524K	Date: 05/31/24	Customer P.O. #: 81115062
Payment Terms: Net 45 Days	Salesperson: Jeremy Comer	
Customer Code: 106073		

Remarks:

Quantity	Description	U/M	Unit Price	Extension
5.000	Labor	ea	101.140	505.70
1.000	Fuel	ea	39.300	39.30
1.000	Truck	ea	775.000	775.00
			<b>Total:</b>	<b>1,320.00</b>
			<b>Current Due:</b>	<b>1,320.00</b>

work performed we 6.1.2024



ULTIMATE PARENT ACCOUNT:  
Broadway Enerfab

REPORT FOR:  
Broadway Electric Service Corp  
0496-00-255722-1  
MAY-01-2024 TO MAY-31-2024

PAGE 165

## Purchase Activity Report

CARD NUMBER	CARD EMBOSING	VEHICLE/ASSET IDENTIFIER	VEHICLE DESCRIPTION	PLATE (ST)	VIN	DEPARTMENT						
			TRADESMAN 4X4 CREW CAB			10850						
DATE MM-DD	TIME	SITE ADDRESS	TICKET NUMBER	PROMPT INFO	TRAN CODE	ODOM.	PROD UNITS	COST/ UNIT	FUEL \$	SERVICE \$	OTHER \$	GROSS \$
05-08	15:17	PREVIOUS ODOMETER 981 Dunbar Village Plz P, Dunbar, WV	00029950	D WILLIAMSON	OP	39,638	39,957 UNL	3.528	78.60			78.60
		PERIOD TOTALS				319		22,274	78.60			78.60
		YTD TOTALS				*****		22,274 254,934	78.60 850.19			78.60 850.19
		PERIOD AVGS: DPU, PPU, CPD				14.32		3.529	0.25	*****		
		YTD AVG: PPU				*****			*****	*****		
***** TO ENSURE MORE ACCURATE MILEAGE REPORTING, VEHICLE DISTANCE STATISTICS ARE NOT CALCULATED WHEN KEY ODOMETER READINGS ARE NOT WITHIN AN ACCEPTABLE RANGE.												

AE00087701  
\$39.30

AE00087701  
\$39.30

Transaction and Fee legend can be found on the last page of this report.



INVOICE

Date: 10/01/2024

Division: Corporate Trust

Invoice No.:

67771

AMERICAN ELECTRIC COMPANY  
DO NOT MAIL  
EMAIL: CASH\_MANAGEMENT\_COLUMBUS@AEP.COM  
DO NOT MAIL OH

KENTUCKY POWER COMPANY 4.33% SENIOR NOTE  
SERIES B DUE DECEMBER 30, 2026

Account #



Billing Period: 12/30/2024 - 12/29/2025

BALANCE CARRIED FORWARD:

\$0.00

PREVIOUS AMOUNT BILLED:

\$1,150.00

AMOUNT RECEIVED:

\$1,150.00

ADMINISTRATION FEE  
FISCAL AGENT

\$750.00

OTHER FEES AND EXPENSES  
WIRE FEE (\$20 PER WIRE)

\$400.00

TOTAL DUE

\$1,150.00

Please Direct Wires and ACH to:  
Huntington National Bank  
Columbus, Ohio  
ABA#  
FBO: Account # listed above

Remit Checks To:  
Huntington National Bank  
Attn Corporate Trust Dept  
L - 3632  
Columbus, Ohio 43260  
**\*\*Account# Must be on Check or  
Invoice Must Accompany Check**

JIM SCHULTZ 614-331-8698

Invoices are payable upon receipt



INVOICE

Date: 07/01/2024 Division: Corporate Trust Invoice No.: 65946

AMERICAN ELECTRIC COMPANY  
DO NOT MAIL  
EMAIL: CASH\_MANAGEMENT\_COLUMBUS@AEP.COM  
DO NOT MAIL OH

KENTUCKY POWER COMPANY 4.18% SENIOR  
NOTE SERIES A DUE SEPTEMBER 30, 2026

Account #

Billing Period: 09/29/2024 - 09/28/2025

BALANCE CARRIED FORWARD: \$0.00

PREVIOUS AMOUNT BILLED: \$1,990.00  
AMOUNT RECEIVED: \$1,990.00

ADMINISTRATION FEE  
FISCAL AGENT \$750.00

OTHER FEES AND EXPENSES  
WIRE FEE (\$20 PER WIRE) \$1,240.00

=====

TOTAL DUE	\$1,990.00
-----------	------------

Please Direct Wires and ACH to:  
Huntington National Bank  
Columbus, Ohio  
ABA# [REDACTED]  
FBO: Account # listed above

Remit Checks To:  
Huntington National Bank  
Attn Corporate Trust Dept  
L - 3632  
Columbus, Ohio 43260  
**\*\*Account# Must be on Check or  
Invoice Must Accompany Check**

JIM SCHULTZ 614-331-8698

Invoices are payable upon receipt



DOR 1



BNY MELLON

The Bank of New York Mellon  
Trust Company, N.A.

# INVOICE

American Electric Power Company, Inc.  
Attn: Treasury Operations 26th Floor  
1 Riverside Plaza  
Columbus, OH 43215

000001

Invoice Number: 252-2639062  
Account Number: [REDACTED]  
Invoice Date: 13-Jun-24  
Cycle Date: 26-Jun-24  
Administrator: Gareth Zerkle  
Phone Number: (614) 775-5259  
Currency: USD

WEST VIRGINIA ECONOMIC DEVELOPMENT AUTHORITY SOLID WASTE DISPOSAL FACILITIES REVENUE  
REFUNDING BOND (KENTUCKY POWER COMPANY - MITCHELL PROJECT), SERIES 2014A

	Quantity	Rate	Proration	Subtotal	Total
<b>Flat</b>					
Administration Fee					2,000.00
For the period: June 26, 2024 to June 25, 2025					
<b>Expenses</b>					
Out of Pocket Expense**					100.00

Invoice Total: 2,100.00  
Satisfied To Date: 0.00  
Balance Due: 2,100.00

\*\*Miscellaneous out-of-pocket expenses include postage, stationery, supplies, telephone, express mail, IRS forms, etc. (if applicable).

Terms: Payable upon receipt. Please reference the invoice and account number with your remittance.  
Our Tax ID Number is [REDACTED] Please fax Taxpayer Certification requests to (732) 667-9576.  
The Bank of New York Mellon Trust Company, N.A is located at 333 South Hope Street - Suite 2525,  
Los Angeles, CA 90071

Check Payment Instructions:  
The Bank of New York Mellon  
Corporate Trust Department  
P.O. Box 392013  
Pittsburgh, PA 15251-9013  
Please enclose billing stub.

Wire and ACH Payment Instructions:  
The Bank of New York Mellon  
ABA Number: [REDACTED]  
Account Number: [REDACTED]  
Account Name: [REDACTED]  
Please reference Invoice Number: [REDACTED]

## Billing Stub

WEST VIRGINIA ECONOMIC DEVELOPMENT AUTHORITY SOLID  
WASTE DISPOSAL FACILITIES REVENUE REFUNDING BOND  
(KENTUCKY POWER COMPANY - MITCHELL PROJECT), SERIES  
2014A

Invoice Number: 252-2639062  
Account Number: KPCOMIT2014A  
Invoice Date: 13-Jun-24  
Cycle Date: 26-Jun-24  
Administrator: Gareth Zerkle  
Phone Number: (614) 775-5259  
Amount: 2,100.00 USD

0000006019512520263906200000000000002100001

Facility: Ashland Pop Site  
Lease No.: 10038/1000255

**FIRST AMENDMENT TO LEASE**

This **FIRST AMENDMENT TO LEASE** ("Amendment") is made as of the 22<sup>nd</sup> day of March 2024, by and between **SHANNON WELLS** ("Lessor"), and **KENTUCKY POWER COMPANY** ("Lessee").

**WHEREAS**, Lessor and AEP Communications, LLC ("Original Lessee") entered into a certain Lease dated January 16, 2004 ("Lease"), for certain premises located at [REDACTED] (the "Leased Premises"), as further described in Exhibit A, attached to the Lease.

**WHEREAS** Lessor and Lessee desire to amend the Lease as set forth below.

**NOW THEREFORE**, in consideration of the mutual covenants and agreements contained herein, Lessor and Lessee agree to amend the Lease as follows:

2. Term. The Term of the Lease is hereby amended to extend on a year-to-year basis, commencing January 16, 2024.

3. Rent. The monthly rental consideration shall be Two Thousand One Hundred Twenty-Five Dollars and NO/100 (\$2,125.00) per month due and payable on or before the sixteenth day of each month within the extended lease term beginning on January 16, 2024 (back rent to be paid with execution hereof).

4. Lessor shall have the right to audit all rents received by Lessee annually as it is understood that the rent set forth herein is to represent 50% of the total gross rents received by the Lessee for operating and maintaining the site at the leased premises denoted herein.

Except as modified by this First Amendment, the Lease shall remain in full force and effect.

**IN WITNESS WHEREOF**, this First Amendment has been executed by the parties hereto as of the date first written above.

LESSOR:  
Shannon Wells

By: Shannon Wells

LESSEE:  
Kentucky Power Company

By: P. Todd Ireland DS  
CB DS  
MW  
C7F9EB570525421...  
P. Todd Ireland  
Manager, Real Estate Asset Management  
American Electric Power Service Corporation  
Authorized Signer

This instrument prepared by Lessee.



Account Number  
Invoice Number  
Billing Date  
Due Date

Page 1 of 2  
0123-0017  
686713  
May 10, 2025  
June 9, 2025

**TO PAY BY ACH/CREDIT CARD:**

Call 866-838-5079

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

**FOR BILLING QUESTIONS:**

Call our National Client Care Team at 866-838-5079 or email them at [nationalhelp@thryv.com](mailto:nationalhelp@thryv.com)

**Account Summary**

Previous Balance	\$ .00
Current Print Charges	\$2,328.00
Current Digital Charges	\$ .00
Other Charges and Credits	\$ .00
Total Amount Due	\$2,328.00

If payment is not received on or before the due date, a late charge will be assessed.

**Important Account Information**

If your invoice has a previous balance this is a friendly reminder. We're here to help. Call 877-503-3996 Opt #3 if you'd like to discuss ways to handle your balance. We value your business and want to work with you. If payment has been sent, please disregard this notice.

-----  
Please return this portion with your payment

Correspondence sent to the address on this payment stub will not be read or responded to.

Account Number 0123-0017  
**Due Date June 9, 2025**  
Total Charges Due \$2,328.00

ATTN: Terry Darst-Exec. Admin. Assoc.  
Aep/Kentucky Power Co  
1 Riverside Plaza  
Columbus, OH 43215-2373 USA

*Make checks payable to:*  
Thryv-BNI  
ATTN: Accounts Receivable  
P.O. Box 646301  
Dallas, TX 75264-6301

CANADIAN ADVERTISING IS BILLED IN US CURRENCY; WE ACCEPT PAYMENTS IN CANADIAN CURRENCY HOWEVER; THE FUNDS WILL BE CONVERTED TO US EQUIVALENT.

ARQIH0AP



Account Number  
Invoice Number  
Billing Date  
Due Date

Page 2 of 2  
0123-0017  
686713  
May 10, 2025  
June 9, 2025

### Current Print Charges

AEP-KENTUCKY POWER CO 000300

Directory Name	Directory Number	Directory Duration	Life	Install	Amount Due
* KY Ashland Area	103351	4/2025 To 04/2027	24R	1 of 1	\$931.20
* KY Grayson-Olive Hill	103352	4/2025 To 04/2027	24R	1 of 1	\$465.60
* KY Harlan	29371	4/2025 To 04/2027	24R	1 of 1	\$931.20
<b>Total Current Print charges</b>					<b>\$2,328.00</b>

### Current Digital Charges

No Current Digital Charges.

**Total Current Digital Charges** **\$ .00**

\* indicates new charge

### Other Charges and Credits

No Other Charges and Credits.

**Total Other Charges and Credits** **\$ .00**

### Payments Received Since Last Bill

Check Number	Invoice Number	Date Received	Amount
<b>No payment received since last bill</b>			
<b>Total Payments Received</b>			<b>\$ .00</b>



Corporate Trust Services  
EP-MN-WN3L  
60 Livingston Ave.  
St. Paul, MN 55107

Invoice Number: 7590970  
Account Number: 802777000  
Invoice Date: 12/24/2024  
Direct Inquiries To: Scott, Melody M  
Phone: (804)-343-1560

KENTUCKY POWER COMPANY-DIST  
TREASURY OPERATIONS 26TH FLOOR  
1 RIVERSIDE PLAZA  
COLUMBUS OH 43215

KENTUCKY POWER COMPANY

The following is a statement of transactions pertaining to your account. For further information, please review the attached.

STATEMENT SUMMARY

PLEASE REMIT BOTTOM COUPON PORTION OF THIS PAGE WITH CHECK PAYMENT OF INVOICE.

TOTAL AMOUNT DUE \$2,420.00

All invoices are due upon receipt.

Please detach at perforation and return bottom portion of the statement with your check, payable to U.S. Bank.

KENTUCKY POWER COMPANY

Invoice Number: 7590970  
Account Number: 802777000  
Current Due: \$2,420.00  
  
Direct Inquiries To: Scott, Melody M  
Phone: (804)-343-1560

Wire Instructions:

U.S. Bank  
ABA # [REDACTED]  
Acct # [REDACTED]  
Trust Acct # [REDACTED]  
Invoice # [REDACTED]  
Attn: [REDACTED]

Please mail payments to:

U.S. Bank  
CM-9690  
PO BOX 70870  
St. Paul, MN 55170-9690





Corporate Trust Services  
EP-MN-WN3L  
60 Livingston Ave.  
St. Paul, MN 55107

Invoice Number: 7590970  
Invoice Date: 12/24/2024  
Account Number: 802777000  
Direct Inquiries To: Scott, Melody M  
Phone: (804)-343-1560

KENTUCKY POWER COMPANY

Accounts Included 802777000  
In This Relationship:

CURRENT CHARGES SUMMARIZED FOR ENTIRE RELATIONSHIP				
Detail of Current Charges	Volume	Rate	Portion of Year	Total Fees
04120 Paying Agent	1.00	2,420.00	100.00%	\$2,420.00
<b>Subtotal Administration Fees - In Advance 12/01/2024 - 11/30/2025</b>				<b>\$2,420.00</b>
<b>TOTAL AMOUNT DUE</b>				<b>\$2,420.00</b>




**Invoice**  
 2774233

 PO Box 4029  
 Frankfort, KY 40604-4029

**Invoicing Date:** 10/31/2024  
**Member ID:** 1788  
**Invoice Due:** 01/01/2025

 Ms. Trisha Blum  
 AEP/Kentucky Power Company  
 1645 Winchester Avenue  
 Ashland, KY 41101

Description	Qty	Rate	Amount
KAM Membership Dues Investment 01/01/2025 to 12/31/2025	1.00	2,994.00	2,994.00

KAM is a tax-exempt 501(c)(6) business association. For tax purposes, 100% of a KAM membership dues or sponsorship payment should be treated as an ordinary business expense and not as a charitable contribution. KAM pays a proxy tax on lobbying expenses. Companies are allowed to deduct 100% of KAM membership dues or sponsorship payments as a business expense and need not prorate dues to lobbying expenses.

<b>Total:</b>	<b>2,994.00</b>
<b>Amt Paid:</b>	<b>0.00</b>
<b>Balance Due:</b>	<b>2,994.00</b>

Member ID	Invoice	Due Date	Total Due	Total Payment Enclosed
1788	2774233	01/01/2025	\$2,994.00	\$

Please verify address and provide corrections

Correct Address

Make checks payable to:

 Ms. Trisha Blum  
 AEP/Kentucky Power Company  
 1645 Winchester Avenue  
 Ashland, KY 41101

 Kentucky Association of Manufacturers  
 PO Box 4029  
 Frankfort, KY 40604-4029
☐ MasterCard☐ Visa☐ Discover☐ American Express

Card No.

Exp. Date

Signature

Sec. Code

Log in at <http://www.KAM.us.com> for online payment options
 For changes or updates to company profile or questions about invoicing,  
 please email Shelley Goodwin at [s.goodwin@kam.us.com](mailto:s.goodwin@kam.us.com) or call 502.352.2485.

Albon Meade & Sons Construction

PO Box 337  
STANVILLE, KY 41659

Invoice

Date	Invoice #
11/25/2024	4170

Bill To
AEP ASHLAND POP

Description	Amount
PO 81405992  INSTALLED A NEW SPECIAL ORDER 46" DOOR IN EXISTING FRAME. DOOR WILL BE INSTALLED WITH A NEW ROTON HINGE AND BE PAINTED WITH 2 COATS OF ACRYLIC ENAMEL. WE WILL REINSTALL EXISTING HARDWARE.  PRICE IS	3,750.00
	<b>Total</b> \$3,750.00





INVOICE

Date: 07/01/2024 Division: Corporate Trust Invoice No.: 65943

AMERICAN ELECTRIC COMPANY  
DO NOT MAIL  
EMAIL: CASH\_MANAGEMENT\_COLUMBUS@AEP.COM  
DO NOT MAIL OH

KENTUCKY POWER COMPANY 3.13% NOTES,  
SERIES F, G, H, + I

Account # 1085001544

Billing Period: 09/12/2024 - 09/11/2025

-----  
-PREVIOUS AMOUNT BILLED: \$4,160.00  
AMOUNT RECEIVED: \$4,160.00  
-----

KENTUCKY PWR CO SER F NOTES (KYPWRCOSERF)	\$750.00
KENTUCKY PWR CO SERIES G NOTES (KYPWRCOSERG)	\$750.00
KENTUCKY PWR CO SER H NOTES (KYPWRCOSERH)	\$750.00
KENTUCKY PWR CO SERIES I NOTES (KYPWRCOSERI)	\$750.00
WIRE FEE (\$20 PER WIRE)	\$1,160.00

=====

TOTAL DUE	\$4,160.00
-----------	------------

Please Direct Wires and ACH to:  
Huntington National Bank  
Columbus, Ohio  
ABA# [REDACTED]  
FBO: Account # listed above

Remit Checks To:  
Huntington National Bank  
Attn Corporate Trust Dept  
L - 3632  
Columbus, Ohio 43260  
**\*\*Account# Must be on Check or  
Invoice Must Accompany Check**

JIM SCHULTZ 614-331-8698

Invoices are payable upon receipt

DOR 1



BNY MELLON

The Bank of New York Mellon  
Trust Company, N.A.

INVOICE

American Electric Power  
Attn: Zach Wnek, Treasury Operations  
1 Riverside Plaza  
26th Floor  
Columbus, OH 43215

000001

Invoice Number: 252-2665883  
Account Number: KENTUCK32  
Invoice Date: 02-Oct-24  
Cycle Date: 08-Oct-24  
Administrator: Yolanda Ash  
Phone Number: 312-827-8639  
Currency: USD

Kentucky Power Company 5.625% Series D Notes due 2032

	<u>Quantity</u>	<u>Rate</u>	<u>Proration</u>	<u>Subtotal</u>	<u>Total</u>
<b>Flat</b>					
Annual Fee as Trustee, Registrar and Paying Agent					4,400.00
For the period: October 08, 2024 to October 07, 2025					
Invoice Total:				4,400.00	
Satisfied To Date:				0.00	
Balance Due:				4,400.00	

Terms: Payable upon receipt. Please reference the invoice and account number with your remittance.  
Our Tax ID Number is [REDACTED] Please fax Taxpayer Certification requests to (732) 667-9576.  
The Bank of New York Mellon Trust Company, N.A is located at 333 South Hope Street - Suite 2525,  
Los Angeles, CA 90071

Check Payment Instructions:  
The Bank of New York Mellon  
Corporate Trust Department  
P.O. Box 392013  
Pittsburgh, PA 15251-9013  
Please enclose billing stub.

Wire and ACH Payment Instructions:  
The Bank of New York Mellon  
ABA Number: [REDACTED]  
Account Number: [REDACTED]  
Account Name: [REDACTED]  
Please reference [REDACTED]

Billing Stub

Kentucky Power Company 5.625% Series D Notes due 2032

Invoice Number: 252-2665883  
Account Number: KENTUCK32  
Invoice Date: 02-Oct-24  
Cycle Date: 08-Oct-24  
Administrator: Yolanda Ash  
Phone Number: 312-827-8639  
Amount: 4,400.00 USD

0000006454212520266588300000000000004400008

Broadway Electric Service Comp  
P O BOX 3250  
Knoxville, TN 37927  
865 524-1851



## Invoice 114522

Bill to: AEP - Columbus, OH 1 Riverside Plaza Columbus, OH 43215	Job: 4690 AEP FC John King 404 29TH STREET WEST CHARLESTON, WV 25387
---------------------------------------------------------------------------	-------------------------------------------------------------------------------

Invoice #: 114522 Date: 05/31/24 Payment Terms: Net 45 Days Customer Code: 106073	Customer P.O. #: 81115062 Salesperson: Jeremy Comer
--------------------------------------------------------------------------------------------	--------------------------------------------------------

Remarks: TIME & MATERIAL BILLING NUMBER: 062

Quantity	Description	U/M	Unit Price	Extension
31.000	Labor	ea	101.140	3,135.34
3.000	Per Diem	ea	175.000	525.00
1.000	Truck	ea	1,550.000	1,550.00
1.000	Fuel	ea	567.710	567.71
<b>Total:</b>				<b>5,778.05</b>
<b>Current Due:</b>				<b>5,778.05</b>

work performed we 6.1.2024

[illegible]

AEP Transmission

Contractor Name:		Besco
Contract / Release:		81115062
Week Start Date:		5/27/2024
Jobsite / Staging Location:		Greenup TS, KY
Employee Name		
1	John D. King	533 Truman Rd. Charleston, WV 25302
2		200 Watertower Rd. Greenup, KY
3		
4		
5		
6		
7		
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9		
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16		
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18		
19		
20		
Per Diem Eligibility		Per Diem Eligibility
Per Diem eligibility shall be per the terms of the Contract and Release specified above.		



I attest that all items being submitted for payment are in accordance with the terms of the contract.

John D. King 6/1/2024

Contractor shall maintain employee home address of record information and make available to Owner's Designated Representative(s) upon request.



ULTIMATE PARENT ACCOUNT:  
Broadway Enerfab

REPORT FOR:  
Broadway Electric Service Corp  
0496-00-255722-1  
MAY-01-2024 TO MAY-31-2024

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## Purchase Activity Report

CARD NUMBER		CARD EMBOSING	VEHICLE/ASSET IDENTIFIER	VEHICLE DESCRIPTION	PLATE (ST)	VIN	DEPARTMENT					
				2022 DODGE RAM 2500			10850					
DATE	TIME	SITE ADDRESS	TICKET NUMBER	PROMPT INFO	TRAN CODE	ODOM.	PROD UNITS	COST/UNIT	FUEL \$	SERVICE \$	OTHER \$	GROSS \$
05-01	19:22	PREVIOUS ODOMETER										
05-07	13:13	2 Green Rd, South Charleston, WV	88008	J KING	OP	62,872	27,010	3.499	94.51			94.51
05-07	13:13	11825 US 23 Hwy, Greenup, KY	40017	J KING	OP	63,557 UNL	23,848	3.349	79.20			79.20
05-13	18:32	75 Norman Morgan Blvd, Logan, WV	57028	J KING	OP	63,916 UNL	25,013	3.498	87.52			87.52
05-16	06:01	2 Green Rd, South Charleston, WV	03032	J KING	OP	64,291 UNL	26,007	3.489	90.74			90.74
05-20	18:14	12541 US Route 60, Ashland, KY	91002	J KING	OP	64,556 UNL	19,000	3.198	60.78			60.78
05-24	12:28	11825 US 23 Hwy, Greenup, KY	38011	J KING	OP	64,839 UNL	24,006	3.499	84.00			84.00
05-30	13:37	11825 US 23 Hwy, Greenup, KY	72001	J KING	OP	65,145 UNL	21,379	3.319	70.96			70.96
		PERIOD TOTALS				2,273	166,063		567.71			567.71
		YTD TOTALS				9,650	713,096		2,316.88			2,316.88
		PERIOD AVGS: DPU, PPU, CPD				13.69		3.419	0.25	*****		
		YTD AVGS: DPU, PPU, CPD				13.53			0.24	*****		
K10768448001 \$283.88												
AF00087701 \$283.84												

K10768448001 \$283.88  
RF00087701 \$283.84

Transaction and Fee legend can be found on the last page of this report.

Broadway Electric Service Comp  
P O BOX 3250  
Knoxville, TN 37927  
865 524-1851



## Invoice 114359

Bill to: AEP - Columbus, OH 1 Riverside Plaza Columbus, OH 43215	Job: 4690 AEP FC John King 404 29TH STREET WEST CHARLESTON, WV 25387
---------------------------------------------------------------------------	-------------------------------------------------------------------------------

Invoice #: 114359 Date: 05/23/24 Payment Terms: Net 45 Days Customer Code: 106073	Customer P.O. #: 81115062 Salesperson: Jeremy Comer
--------------------------------------------------------------------------------------------	--------------------------------------------------------

Remarks: TIME & MATERIAL BILLING NUMBER: 058

Quantity	Description	U/M	Unit Price	Extension
40.000	Labor	EA	101.140	4,045.60
4.000	Per Diem	EA	175.000	700.00
<b>Total:</b>				<b>4,745.60</b>
<b>Current Due:</b>				<b>4,745.60</b>

WORK PERFORMED WE 5.11.2024

AEP-BESCO								
Weekly Time Sheet			4 Digit Job Number:			4690		
Name: John King			Week Ending Date: 5/11/2024					
Date	AEP Work Order Number	Project Name	State	Start Time	Stop Time	Hours	Per Diem	Truck
5/6/2024	AE00087701	Greenup TS (UBD AT&T)	KY			12.00	1	yes
5/7/2024	AE00087701	Greenup TS (UBD AT&T)	KY			8.00	1	yes
5/8/2024	AE00087701	Greenup TS (UBD AT&T)	KY			10.00	1	yes
5/9/2024	AE00087701	Greenup TS (UBD AT&T)	KY			10.00	1	yes
				<b>Totals</b>		<b>40.00</b>	<b>4</b>	
Comments								



### AEP Transmission

<b>Contractor Name:</b>	Besco				
<b>Contract / Release:</b>	81115062				
<b>Week Start Date:</b>	5/6/2024				
<b>Jobsite / Staging Location:</b>	Greenup TS, KY				
	<b>Employee Name</b>		<b>Mileage to Site</b>	<b>Per Diem (Y/N)</b>	<b>Days Requested</b>
1	John D. King	533 Truman Rd. Charleston, WV 25302			
2		200 Watertower Rd. Greenup, KY	85	Y	4
3					
4					
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20					
Per Diem Eligibility					
Per Diem eligibility shall be per the terms of the Contract and Release specified above.					



I attest that all items being submitted for payment are in accordance with the terms of the contract.  
John D. King 5/11/2024

*Contractor shall maintain employee home address of record information and make available to Owner's Designated Representative(s) upon request.*

Broadway Electric Service Comp  
P O BOX 3250  
Knoxville, TN 37927  
865 524-1851



## Invoice 114420

Bill to: AEP - Columbus, OH 1 Riverside Plaza Columbus, OH 43215	Job: 4690 AEP FC John King 404 29TH STREET WEST CHARLESTON, WV 25387
---------------------------------------------------------------------------	-------------------------------------------------------------------------------

Invoice #: 114420 Date: 05/29/24 Payment Terms: Net 45 Days Customer Code: 106073	Customer P.O. #: 81114955 Salesperson: Jeremy Comer
--------------------------------------------------------------------------------------------	--------------------------------------------------------

Remarks: TIME & MATERIAL BILLING NUMBER: 061

Quantity	Description	U/M	Unit Price	Extension
46.000	Labor	EA	101.140	4,652.44
4.000	Per Diem	EA	175.000	700.00
			<b>Total:</b>	<b>5,352.44</b>
			<b>Current Due:</b>	<b>5,352.44</b>

WORK PERFORMED WE 5.25.2024

[illegible]

### AEP Transmission

<b>Contractor Name:</b>		Besco			
<b>Contract / Release:</b>		81115062			
<b>Week Start Date:</b>		5/20/2024			
<b>Jobsite / Staging Location:</b>		Greenup TS, KY			
	Employee Name		Mileage to Site	Per Diem (Y/N)	Days Requested
1	John D. King	533 Truman Rd. Charleston, WV 25302			
2		200 Watertower Rd. Greenup, KY	90	Y	4
3					
4					
5					
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20					
Per Diem Eligibility					
Per Diem eligibility shall be per the terms of the Contract and Release specified above.					



an AEP COMPANY

I attest that all items being submitted for payment are in accordance with the terms of the contract.  
John D. King 5/25/2024

*Contractor shall maintain employee home address of record information and make available to Owner's Designated Representative(s) upon request.*



## Membership Renewal - Invoice No. 18352024

Ms. Cindy Wiseman  
President & CEO  
AEP - Kentucky Power Co.  
855 Central Ave Ste 200  
Ashland, KY 41101-7482

(606) 327-2604  
cgwiseman@aep.com

Date: 11/21/2024  
Original Join Date: 05/01/1948  
Membership Dates: 12/01/2024 - 11/30/2025

KCC Federal Tax ID: [REDACTED]

Please verify information at left and note any updates.

**Remit to:**  
Kentucky Chamber of Commerce  
464 Chenault Road  
Frankfort, KY 40601

Investing in membership with the Kentucky Chamber of Commerce makes good business sense. Whether you're a small, family-owned business or a Fortune 500 company, we have the tools to help you succeed, because our business is growing your business.

Company	Member Number	Due Date	Membership Dues
AEP - Kentucky Power Co.	1835	12/1/2024	25,000.00
<b>Chamber Action Fund</b> Your voluntary contribution to the Chamber Action Fund is used in the most critical situations to garner needed public support on important business issues. Action Fund dollars are used exclusively to advance member-supported issues and are not used for political activity.			\$50.00
<i>Membership dues are not deductible as a charitable contribution. In compliance with the Omnibus Budget Reconciliation Act of 1993, 80 percent of your dues may be deductible as an ordinary business expense and are not allocable to lobbying activity.</i>			
<b>Total Due</b>			\$25,050.00

Please return this portion with payment.

Company	Member Number	Due Date	Membership Dues	
AEP - Kentucky Power Co.	[REDACTED]	12/1/2024	25,000.00	
<b>Please select your area(s) of interest:</b>			Action Fund	\$50.00
<input type="checkbox"/> Human Resources <input type="checkbox"/> Political Education <input type="checkbox"/> Fiscal Policy <input type="checkbox"/> Health & Wellness <input type="checkbox"/> Energy & Environmental <input type="checkbox"/> OSHA <input type="checkbox"/> Manufacturing <input type="checkbox"/> Small Business <input type="checkbox"/> Workers' Compensation <input type="checkbox"/> Education & Workforce Dev.				
			<b>Total Due</b>	\$25,050.00

<b>Pay by Check</b>  Amount: \$ _____ Check # _____	<b>Pay by Credit Card (select one)</b> VISA    MasterCard    AMEX    Discover  Card # _____ Exp. Date _____ CVV: _____ Signature (required) _____ Billing Zip Code: _____
--------------------------------------------------------------	------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

# Invoice for Membership Dues



Edison Electric  
INSTITUTE

**MR. WILLIAM J. FEHRMAN**  
PRESIDENT AND CEO  
AMERICAN ELECTRIC POWER  
1 RIVERSIDE PLAZA  
COLUMBUS, OH 43215

Date	Invoice Number
11/21/2024	DUES202505

**Payment due on or before 1/31/2025**

Description	Total
<b>2025 EEI Membership Dues for:</b>	
Regular Activities of Edison Electric Institute <sup>1</sup>	\$2,780,226
Industry Issues <sup>2</sup>	\$278,023
Restoration, Operations, and Crisis Management Program <sup>3</sup>	\$15,000
<b>2025 Contribution to The Edison Foundation, which funds the Institute for Electric Innovation and the Institute for the Energy Transition. <sup>4</sup></b>	<b>\$50,000</b>
<b>Total</b>	<b>\$3,123,249</b>
<p><sup>1</sup> The portion of 2025 membership dues relating to influencing legislation and political campaign activity, including activities covered by Section 162(e) of the Internal Revenue Code (IRC) and contributions to groups organized under IRC sections 527 and 501(c)(4), is estimated to be 16%.</p> <p><sup>2</sup> The portion of the 2025 industry issues support relating to influencing legislation and political campaign activity, including activities covered by IRC Section 162(e) and contributions to groups organized under IRC sections 527 and 501(c)(4), is estimated to be 27%.</p> <p><sup>3</sup> The Restoration, Operations, and Crisis Management Program is related to improvements to industry-wide responses to major outages (e.g., National Response Event); continuity of industry and business operations; and EEI's support and coordination of the industry during times of crisis (extreme weather events, wildfires, cyber, pandemic, etc.). No portion of this assessment is allocable to influencing legislation.</p> <p><sup>4</sup> The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.</p>	

## PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

**Beneficiary's Bank:**  
**Bank's Address:**  
**Bank's ABA Number:**  
**Beneficiary:**  
**Beneficiary's Acct No:**  
**Beneficiary's Address:**  
  
**Beneficiary Reference:**



Please refer any membership questions to Stephanie Voyda, Senior Vice President, Communications and Member Engagement, at (202) 508-5612 or [svoyda@eei.org](mailto:svoyda@eei.org), or accounting questions to Teresa Boness, Chief Financial Officer, at (202) 508-5591 or [tboness@eei.org](mailto:tboness@eei.org).

Edison Electric Institute Dues  
Statistics and Allocation by Company

Company	2023 Retail Customers (2024 Fact Book)	Total Electric Revenues (\$000s) (from 2023 FERC Annual Reporting)		Owned Capacity (MW) (2024 Fact Book)	Average		Regular Activities	Industry Issues	Restoration, Operations and Crisis Management	TAE Contribution	4264000	9302000	4261000
		%	%		%	%							
AEP Generating Company	-	0.00%	181,407	0.96%	1,310	5.69%	61,625.58	6,162.57	332.49	1,108.28	11,523.99	56,596.65	1,108.28
AEP Texas Company	1,111,000	19.85%	1,806,435	9.60%	-	0.00%	272,936.47	27,293.69	1,472.56	4,908.53	51,039.13	250,663.59	4,908.53
Appalachian Power Company	967,000	17.28%	3,752,740	19.95%	6,717	29.15%	615,129.03	61,512.99	3,318.77	11,062.57	115,029.15	564,931.64	11,062.57
Indiana Michigan Power Company	613,000	10.95%	2,305,196	12.25%	3,662	15.89%	362,336.65	36,233.72	1,954.89	6,516.32	67,756.97	332,768.30	6,516.32
Kentucky Power Company	163,000	2.91%	622,722	3.31%	1,075	4.67%	100,900.51	10,090.07	544.38	1,814.61	18,868.40	92,666.56	1,814.61
Kingsport Power Company	49,000	0.88%	239,877	1.27%	-	0.00%	19,928.90	1,992.89	107.52	358.40	3,726.70	18,302.61	358.40
Ohio Power Company	1,527,000	27.28%	3,814,889	20.28%	-	0.00%	440,746.83	44,074.75	2,377.94	7,926.46	82,419.68	404,779.84	7,926.46
Public Service Company of Oklahoma	578,000	10.33%	1,990,014	10.58%	4,488	19.48%	374,239.51	37,424.00	2,019.11	6,730.38	69,982.80	343,699.82	6,730.38
Southwestern Electric Power	548,000	9.79%	2,034,979	10.82%	5,009	21.74%	392,442.34	39,244.29	2,117.32	7,057.74	73,386.73	360,417.22	7,057.74
Wheeling Power Company	41,000	0.73%	395,706	2.10%	780	3.39%	57,652.59	5,765.27	311.05	1,036.83	10,781.04	52,947.87	1,036.83
AEP Appalachian Transmission Co.	-	0.00%	14,175	0.08%	-	0.00%	698.22	69.82	3.77	12.56	130.57	641.24	12.56
AEP Indiana Michigan Transmission Co.	-	0.00%	417,437	2.22%	-	0.00%	20,561.57	2,056.16	110.93	369.78	3,845.01	18,883.65	369.78
AEP Kentucky Transmission Co.	-	0.00%	19,714	0.10%	-	0.00%	971.02	97.10	5.24	17.46	181.58	891.78	17.46
AEP Ohio Transmission Co.	-	0.00%	780,880	4.15%	-	0.00%	38,463.54	3,846.36	207.52	691.73	7,192.68	35,324.74	691.73
AEP Oklahoma Transmission Co.	-	0.00%	172,946	0.92%	-	0.00%	8,518.77	851.88	45.96	153.20	1,593.01	7,823.59	153.20
AEP Southwestern Transmission Co.	-	0.00%	-	0.00%	-	0.00%	-	-	-	-	-	-	-
AEP West Virginia Transmission Co.	-	0.00%	265,436	1.41%	-	0.00%	13,074.47	1,307.45	70.54	235.13	2,444.93	12,007.53	235.13
<b>Total</b>	<b>5,597,000</b>	<b>100.00%</b>	<b>18,814,553</b>	<b>100.00%</b>	<b>23,041</b>	<b>100.00%</b>	<b>2,780,226.00</b>	<b>278,023.00</b>	<b>15,000.00</b>	<b>50,000.00</b>	<b>519,902.37</b>	<b>2,553,346.63</b>	<b>50,000.00</b>

Statistics are based on the year-ended December 31, 2023.  
Revenues are based on the year-ended December 31, 2023.  
Owned Capacity is as of Dec 31, 2023 as required by the EEI.  
Revenue numbers are in thousands.  
Other Segment Reporting Adjustments

EEI Dues													
Company	Activity	GLBU	Department	Project	Work Order	Benefiting Location	Account	Cost Component	ABM Activity	2024 Dues			
AEP Generating Company	Lobbying	153	12378	000001121	G000153	153	4264000	953	289	11,523.99			
AEP Generating Company	Dues	153	12378	000001121	G000153	153	9302000	953	289	56,596.65			
AEP Generating Company	Contributions	153	12378	000001120	G000153	153	4261000	955	294	1,108.28			
AEP Texas Company	Lobbying	211	11404	000001121	G000104	1104	4264000	953	289	51,039.13			
AEP Texas Company	Dues	211	11404	000001121	G000104	1104	9302000	953	282	250,663.59			
AEP Texas Company	Contributions	211	11404	000001120	UTXECON201	1104	4261000	955	284	4,908.53			
Appalachian Power Company	Lobbying	140	12358	000001121	G0001082	1082	4264000	953	289	115,029.15			
Appalachian Power Company	Dues	140	12358	000001121	G0001082	1082	9302000	953	292	564,931.64			
Appalachian Power Company	Contributions	140	12358	000001120	G0001082	1082	4261000	955	294	11,062.57			
Indiana Michigan Power Company	Lobbying	170	12378	000001121	G0001186	1186	4264000	953	289	67,756.97			
Indiana Michigan Power Company	Dues	170	12378	000001121	G0001186	1186	9302000	953	282	332,768.30			
Indiana Michigan Power Company	Contributions	170	12378	000001120	G0001186	1186	4261000	955	294	6,516.32			
Kentucky Power Company	Lobbying	110	11439	000001121	G0001241	1241	4264000	953	289	18,868.40			
Kentucky Power Company	Dues	110	11439	000001121	G0001241	1241	9302000	953	292	92,666.56			
Kentucky Power Company	Contributions	110	11439	000001120	G0001241	1241	4261000	955	284	1,814.61			
Kingsport Power Company	Lobbying	230	12358	000001121	G0001239	1239	4264000	953	289	3,726.70			
Kingsport Power Company	Dues	230	12358	000001121	G0001239	1239	9302000	953	292	18,302.61			
Kingsport Power Company	Contributions	230	12358	000001120	G0001239	1239	4261000	955	294	358.40			
Ohio Power Company	Lobbying	250	12377	000001121	G0000250	1354	4264000	953	269	82,419.68			
Ohio Power Company	Dues	250	12377	000001121	G0000250	1354	9302000	953	292	404,779.84			
Ohio Power Company	Contributions	250	12377	000001120	G0000250	1354	4261000	955	284	7,926.48			
Public Service Company of Oklahoma	Lobbying	167	10188	000001121	G0001059	1059	4264000	953	289	69,982.80			
Public Service Company of Oklahoma	Dues	167	10188	000001121	G0001059	1059	9302000	953	292	343,699.82			
Public Service Company of Oklahoma	Contributions	167	10188	000001120	G0001059	1059	4261000	955	294	6,730.38			
Southeastern Electric Power	Lobbying	159	12415	000001121	G0001445	1445	4264000	953	289	73,386.73			
Southeastern Electric Power	Dues	159	12415	000001121	G0001445	1445	9302000	953	282	360,417.22			
Southeastern Electric Power	Contributions	159	12415	000001120	G0001445	1445	4261000	955	294	7,057.74			
Wheeling Power Company	Lobbying	210	12358	000001121	G0001514	1514	4264000	953	289	10,781.04			
Wheeling Power Company	Dues	210	12358	000001121	G0001514	1514	9302000	953	292	52,947.87			
Wheeling Power Company	Contributions	210	12358	000001120	G0001514	1514	4261000	955	284	1,036.83			
AEP Appalachian Transmission Co.	Lobbying	362	12916	000001121	G0000382	382	4264000	953	289	130.57			
AEP Appalachian Transmission Co.	Dues	362	12916	000001121	G0000382	382	9302000	953	292	641.24			
AEP Appalachian Transmission Co.	Contributions	362	12916	000001120	G0000382	382	4261000	955	294	12.56			
AEP Indiana Michigan Transmission Co.	Lobbying	365	12916	000001121	G0000385	385	4264000	953	289	3,845.01			
AEP Indiana Michigan Transmission Co.	Dues	365	12916	000001121	G0000385	385	9302000	953	292	18,883.65			
AEP Indiana Michigan Transmission Co.	Contributions	365	12916	000001120	G0000385	385	4261000	955	284	369.78			
AEP Kentucky Transmission Co.	Lobbying	364	12916	000001121	G0000384	384	4264000	953	289	181.58			
AEP Kentucky Transmission Co.	Dues	364	12916	000001121	G0000384	384	9302000	953	292	891.78			
AEP Kentucky Transmission Co.	Contributions	364	12916	000001120	G0000384	384	4261000	955	294	17.46			
AEP Ohio Transmission Co.	Lobbying	380	12916	000001121	G0000380	380	4264000	953	289	7,192.68			
AEP Ohio Transmission Co.	Dues	380	12916	000001121	G0000380	380	9302000	953	282	35,324.74			
AEP Ohio Transmission Co.	Contributions	380	12916	000001120	G0000380	380	4261000	955	294	691.73			
AEP Oklahoma Transmission Co.	Lobbying	366	12916	000001121	G0000386	386	4264000	953	289	1,593.01			
AEP Oklahoma Transmission Co.	Dues	366	12916	000001121	G0000386	386	9302000	953	292	7,823.59			
AEP Oklahoma Transmission Co.	Contributions	366	12916	000001120	G0000386	386	4261000	955	284	153.20			
AEP Southwestern Transmission Co.	Lobbying	388	12916	000001121	G0000388	388	4264000	953	289	0.00			
AEP Southwestern Transmission Co.	Dues	388	12916	000001121	G0000388	388	9302000	953	292	0.00			
AEP Southwestern Transmission Co.	Contributions	388	12916	000001120	G0000388	388	4261000	955	294	0.00			
AEP West Virginia Transmission Co.	Lobbying	363	12916	000001121	G0000383	383	4264000	953	289	2,444.93			
AEP West Virginia Transmission Co.	Dues	363	12916	000001121	G0000383	383	9302000	953	292	12,007.53			
AEP West Virginia Transmission Co.	Contributions	363	12916	000001120	G0000383	383	4261000	955	284	235.13			
GRAND TOTAL										3,123,249.00			





**Invoice**

Fed Tax ID	Date	Invoice #
56-1173448	6/28/2024	2406-39

<b>Bill To</b>
American Electric Power 1 Riverside Plaza Columbus, Ohio 43215 invoice@aep.com

<b>Ref:</b>
Heather Mann

<b>Remit To</b>
Bellomy Research, Inc. Accounts Receivable 175 Sunnynoll Court Winston-Salem, NC 27106

Bellomy Project #	Project Title	PO #	Contract #	Terms	Due Date
16288	AEP Insight Panel	80907542X103	028499500000X103	Net 30	7/28/2024
Description of charges			Information Only	Amount	
Q2 2024 Panel Charges                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         					

**Invoice**

Fed Tax ID	Date	Invoice #
56-1173448	3/26/2025	2503-26

<b>Bill To</b>
American Electric Power 1 Riverside Plaza Columbus, Ohio 43215 invoice@aep.com

<b>Ref:</b>
Heather Mann

<b>Remit To</b>
Bellomy Research, Inc. Accounts Receivable 175 Sunnynoll Court Winston-Salem, NC 27106

Bellomy Project #	Project Title	Wrk Authorization	Contract #	Terms	Due Date
16288	AEP Residential Panel	81808717	02849950	Net 45	5/10/2025
Description of charges			Information Only	Amount	
Q1 2025 Panel Charges			\$45,900.00	45,900.00	
Q1 2025 Incentives				200.00	
KPI Interpretation Incentives			\$ 200.00		
			</		

**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 Certain Regulatory And Accounting       )  
Treatments; and (4) All Other Required Approvals       )  
And Relief                                                         )

Case No. 2025-00257

**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. 2025-00257**

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**DIRECT TESTIMONY OF  
JACLYN N. COST ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.     My name is Jaclyn N. Cost. I am employed by AEPSC as a Regulatory Consultant Staff  
3           within Regulatory Pricing and Analysis. My business address is 1 Riverside Plaza,  
4           Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric  
5           Power Company Inc. (“AEP”), the parent Company of Kentucky Power Company  
6           (“Kentucky Power” or the “Company”).

**II. BACKGROUND**

7   **Q.     PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
8   **PROFESSIONAL EXPERIENCE.**

9   A.     I graduated from Walsh University with a Bachelor of Arts degree in Accounting and  
10          Finance in 2013. I began my career as an Accountant for Innovative Mattress Solutions  
11          (“IMS”) where I performed various reconciling duties for each of the company’s retail  
12          stores. After IMS, I accepted an Accounting position with AEPSC within the Fuel  
13          department of Utility and Energy Accounting. In 2017, I accepted a position in  
14          Regulatory working within the Pricing and Analysis team where I hold my current role.

1    **Q.    PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.**

2    A.    My responsibilities include preparing cost-of-service studies for regulatory filings and  
3           providing regulatory support and analysis for pricing matters associated with Kentucky  
4           Power and other AEP electric-utility operating companies.

5    **Q.    HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY**  
6           **REGULATORY PROCEEDING?**

7    A.    Yes. I have presented testimony on behalf of the AEP operating companies numerous  
8           times before the regulatory bodies of Virginia and Kentucky. In Kentucky, I presented  
9           testimony in Case No. 2023-00159 on behalf of the Company.

### **III.    PURPOSE OF TESTIMONY**

10   **Q.    WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
11       **PROCEEDING?**

12   A.    The purpose of my Direct Testimony is to support the Kentucky Power jurisdictional  
13       cost-of-service study through which the cost to provide service to the Company's retail  
14       customers is developed. A copy of the Kentucky Power jurisdictional cost-of-service  
15       study is included in Section V of the Company's application. Additionally, I support  
16       adjustment W18-Removal of Wholesale Customer Load, detailed in Section V,  
17       Exhibit 2.

18   **Q.    ARE YOU SPONSORING ANY SCHEDULES?**

19   A.    Yes. I am sponsoring the following schedules filed with the Company's Application:

- 20           •    Section V, Schedule 3 – Capitalization;
- 21           •    Section V, Schedule 4 – Jurisdictional Cost-of-Service;
- 22           •    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 K 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, as well as known and measurable changes to the test year level of expenditures. These Uniform System of Accounts are reflected within Section V, Schedule 4 referred to as “KPCo Total Company Per Books.”

**Q. HOW IS THE INFORMATION USED TO ALLOCATE COSTS TO KENTUCKY POWER’S RETAIL CUSTOMERS?**

A. The costs recorded by FERC account are Total Company per-book amounts pertaining to electric utility operations of the Company for service supplied to all customers, both

1 wholesale and retail. Throughout Kentucky Power's historic test year, retail revenue is  
2 approximately 99% of its total firm sales revenue. The Company's wholesale revenue,  
3 which includes sales to the cities of Olive Hill and Vanceburg, is approximately 1% of  
4 its total revenue. It is therefore necessary to identify and segregate costs related only to  
5 providing service to Kentucky Power's retail customers.

6 **Q. EXPLAIN HOW THE REVENUE REQUIREMENT IS DETERMINED FOR**  
7 **KENTUCKY POWER'S RETAIL CUSTOMERS.**

8 A. A three-step process is followed to assign and allocate costs to determine the total  
9 revenue requirement for the Company's retail customers. These three steps are: (1) the  
10 functionalization of costs, (2) the classification of costs, and (3) the allocation of costs.  
11 By following this process, the Company is able to identify and segregate the costs  
12 related to providing service to Kentucky Power's retail customers. This process can be  
13 seen in Section V, Schedule 4.

14 **Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.**

15 A. Once the Uniform System of Accounts, as mentioned above, are gathered to reflect  
16 Kentucky Power Total Company Per Books the costs are then separated by functional  
17 group as follows:

- 18 1) Production and Purchased Power costs;
- 19 2) Transmission costs;
- 20 3) Distribution costs;
- 21 4) Customer Service costs; and
- 22 5) Administrative and General ("A&G") costs.



1   **Q.     PLEASE DESCRIBE EACH OF THESE FUNCTIONAL GROUPS.**

2   A.     The Production and Purchased Power functional group consists of the costs associated  
3           with power generation and power purchases, as well as their delivery to the bulk  
4           transmission system. The Transmission functional group consists of the costs  
5           associated with the high-voltage system utilized for the bulk transmission of power  
6           from generation sources to the load centers, and to and from interconnected utilities.  
7           The Distribution functional group consists of the radial distribution system that  
8           connects the transmission system to the ultimate customer. The Customer Service  
9           functional group encompasses the costs associated with providing meter reading,  
10          billing and collection, and customer information and services. Finally, the A&G  
11          functional group consists of costs associated with administration of the business,  
12          including salaries, office supplies, and other general operating expenses that are not  
13          directly assignable to other cost functions.

14   **Q.     PLEASE DESCRIBE THE CLASSIFICATION PROCESS.**

15   A.     Once costs have been segregated by functional group, the Company separates the costs  
16           within each functional group into separate classifications. The Company utilized the  
17           following classifications as part of its cost-of-service study:

- 18          1. Demand Costs (fixed costs incurred due to the demand imposed by the customer  
19             regardless of the level of energy sales). These fixed Demand Costs are not based  
20             on how much energy is used, but rather on the maximum capacity the utility needs  
21             to build and maintain to handle customer demand;
- 22          2. Energy Costs (costs that vary with the number of kilowatt hours used by the  
23             customer);

- 1           3. Customer costs (costs that are directly related to the number of customers served);  
 2           and  
 3           4. Labor costs (costs that are directly related to payroll expenses associated with  
 4           serving the customer).

5           The Company classified costs within each functional group as follows:

6	<u>Function</u>	<u>Classification</u>
7	Production and Purchased Power costs	Demand, Energy
8	Transmission costs	Demand
9	Distribution costs	Demand, Customer
10	Customer Service costs	Customer
11	A&G costs	Labor

12           Production plant costs, such as depreciation and return on investment, are considered  
 13           to be fixed demand-related costs. Most fuel and production operation and maintenance  
 14           (“O&M”) expenses are energy-related because they vary with the quantity of energy  
 15           produced. Transmission costs are demand-related because they are fixed and do not  
 16           vary with energy usage. Generally, the distribution system costs are affected by either  
 17           demand or by the number of customers served. Fixed demand-related distribution costs  
 18           will usually vary with the size of the load served; however, they are not based off the  
 19           total energy (kWh) used over time; Customer-related distribution costs vary with the  
 20           number of customers receiving the service. The classification process provides a basis  
 21           on which to allocate different categories of costs (demand, energy, or customer) to the  
 22           utility’s jurisdictions

1   **Q.     PLEASE DESCRIBE THE ALLOCATION PROCESS.**

2   A.     Once the costs have been functionalized and classified, the third and final step is for  
3           the Company to allocate those costs between retail and wholesale customers based on  
4           how the costs are incurred for each. In other words, the allocation process assigns costs  
5           to customers subject to the Commission's jurisdiction (retail customers) or FERC's  
6           jurisdiction (wholesale customers). The allocation process employed by Kentucky  
7           Power is a reasonable, appropriate, and supported method to assign costs as between  
8           the Company's retail and wholesale customer classes.

9           Some costs are directly assignable to a single jurisdiction. For example, costs  
10          related to regulatory deferrals are associated with a specific jurisdiction and are directly  
11          assigned to that jurisdiction. Most costs, however, are attributable to both jurisdictions.  
12          These are joint costs and must be allocated to the jurisdictions by an allocation  
13          methodology that is based on the classification described above for that cost. The  
14          Kentucky Retail Per Books revenues and cost resulting from this allocation process are  
15          reflected in Section V, Schedule 4 as "Kentucky PSC Juris Only." Allocated non-retail  
16          revenues and costs can be found in Section V, Schedule 4 as "Non-KY PSC Juris."

17   **Q.     ARE THE ALLOCATION METHODS EMPLOYED BY THE COMPANY**  
18   **CONSISTENT WITH COST-OF-SERVICE PRINCIPLES?**

19   A.     Yes. The allocation methodologies utilized in the Company's jurisdictional  
20           cost-of-service study were chosen after giving consideration to cost causation  
21           principles. The results of the jurisdictional cost-of-service study can be relied upon to  
22           determine the appropriate revenue requirement for the Company's retail customers and  
23           is consistent with previously approved methodologies by this Commission.

1   **Q.    ARE YOU RESPONSIBLE FOR THE METHODOLOGY USED IN THE**  
2       **PREPARATION OF THE KENTUCKY POWER JURISDICTIONAL**  
3       **COST-OF-SERVICE STUDY?**

4    A.    Yes. I developed the allocation methodology and the allocation factors used to calculate  
5       Kentucky Power's retail jurisdictional cost-of-service consistent with previously  
6       approved methodology used in the Company's last base rate case. Each allocation  
7       method used can be found on Section V, Schedule 4, column "Allocators." A full list  
8       of allocators and their methodology can also be found in Section V, Allocation Factors.

#### **V.    ALLOCATIONS**

9   **Q.    PLEASE DESCRIBE HOW THE ENERGY ALLOCATION FACTOR WAS**  
10       **DETERMINED.**

11   A.    First, total retail customer test year sales of energy (in kilowatt hours) were  
12       accumulated. Next, the total sales of energy were adjusted to the generation level by  
13       applying the appropriate transmission and distribution loss factors (shown in Section  
14       V, Olive Hill – Vanceburg) to obtain the generation-level energy sales to retail  
15       customers. The Composite Loss Factors are used to account for energy losses that  
16       occur during the transmission and distribution of electricity. Finally, the retail  
17       generation-level sales were divided by the net total Company generation-level energy  
18       sales to obtain the retail energy allocation factor. The methodology behind the retail  
19       energy allocation factor can be found in Section V, Schedule 10.

1   **Q.     PLEASE DESCRIBE HOW THE PRODUCTION DEMAND ALLOCATION**  
2   **FACTOR WAS DETERMINED.**

3   A.     One basis for allocating the elements of the cost of property between retail and  
4     wholesale customers is the respective contribution by each of the two classes to the  
5     Company's peak demand. The production demand allocator reflects the coincident  
6     demand of the Company's retail customers at the time of Kentucky Power's monthly  
7     peak demand (the coincident peak demand). In other words, it represents the kilowatt  
8     contribution of retail customers to the Company's monthly peak demand.

9             The production demand allocation factor was calculated by dividing the average  
10    of the 12 monthly retail class coincident demands, adjusted for losses to the generation  
11    levels, by the average of the 12 monthly total Company internal peak demands. The  
12    transmission and sub-transmission demand allocation factors are the same as the  
13    production demand allocation factor.

14            The remaining allocators are internally calculated within the study and can be  
15    found in Section V, Allocation Factors.

16   **Q.     WERE ANY ADJUSTMENTS MADE TO THE PRODUCTION DEMAND AND**  
17   **ENERGY ALLOCATORS?**

18   A.     No adjustments were made.

19   **Q.     PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S**  
20   **ELECTRIC PLANT IN SERVICE.**

21   A.     Electric Plant in Service, refers to the portion of a utility company's assets that are  
22    actively used for generating, transmitting, or distributing electric power. These assets  
23    were separated into different plant categories, Production, Transmission, Distribution,

1 General and Intangible, by function and then allocated accordingly. Kentucky Power's  
2 production plant was allocated to the two jurisdictions using the Production Demand  
3 allocator. The Company's transmission plant was allocated using the transmission  
4 demand allocation factor. With the exception of Olive Hill substation and meter costs  
5 (which are wholesale costs) distribution plant was directly assigned to Kentucky  
6 Power's retail customers. General and intangible plant were allocated using gross plant  
7 production, transmission and distribution factor.

8 **Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S**  
9 **ACCUMULATED PROVISION FOR DEPRECIATION AND**  
10 **AMORTIZATION.**

11 A. Kentucky Power's Accumulated Provision for Depreciation and Amortization, which  
12 refers to the total amount of depreciation and amortization expense that have been  
13 recognized against an asset over its useful life, were functionalized and classified in a  
14 fashion similar to Kentucky Power's Electric Plant in Service. Production,  
15 transmission, and distribution accumulated depreciation were allocated using the same  
16 process as the allocation of the associated plant. General and Intangible plant  
17 accumulated depreciation was allocated using the gross plant production, transmission,  
18 and distribution factor.

19 **Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S**  
20 **OTHER RATE BASE COMPONENTS.**

21 A. Electric Plant held for Future Use, Construction Work in Progress, and Allowance for  
22 Funds Used during Construction were booked by functional group and then allocated  
23 using the associated plant factors. This is consistent with past treatment of these items.

Fuel and Allowance Inventory were allocated using the energy allocation factor. Materials and Supplies were separated into functional groups and allocated by associated plant factors accordingly. Included in Materials and Supplies are Fuel/Allowance Inventory, such as lime, limestone, urea, and urea in-transit, and are allocated using the Energy Allocation Factor. Prepayments, such as prepaid insurance, benefits, and taxes, were allocated using the gross plant total allocation factor.

Accumulated Deferred Investment Tax amounts were provided by Company Witness Hodgson. 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 Production Demand Allocation Factor. Energy-related system sales revenue was allocated on the Energy Allocation Factor.

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

1 functional allocator or directly assigned to Kentucky Power's retail customers where  
2 applicable.

3 **Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S**  
4 **OPERATING AND MAINTENANCE EXPENSES.**

5 A. Production-related O&M expenses were classified as either demand- or energy-related.  
6 The demand component was allocated using the production demand allocation factor  
7 and the energy component was allocated using the energy allocation factor.

8 Transmission-related O&M was allocated based on the gross plant transmission  
9 allocation factor or directly assigned as applicable.

10 Distribution-related O&M was allocated based on the gross plant distribution  
11 allocation factor or directly assigned as applicable.

12 Customer Accounts, Customer Information, and Customer Service expenses  
13 were classified as customer-related and allocated on the total number of customers.

14 A&G expenses were allocated consistent with the allocation of non-A&G O&M  
15 expenses.

16 **Q. PLEASE DESCRIBE THE ALLOCATION OF KENTUCKY POWER'S**  
17 **DEPRECIATION AND AMORTIZATION EXPENSE.**

18 A. Depreciation and Amortization were booked by functional group, then allocated using  
19 the associated plant factors.

20 **Q. PLEASE EXPLAIN HOW KENTUCKY POWER'S TAXES OTHER THAN**  
21 **FEDERAL AND STATE INCOME TAXES WERE ALLOCATED.**

22 A. Taxes Other than Income Taxes were classified based on their nature and purpose as  
23 relating to payroll, property, revenue, demand or energy and allocated accordingly or



1 directly assigned. Payroll taxes are related to labor and allocated on the Operations and  
2 Maintenance Labor allocation factor. Property taxes were allocated using the gross  
3 plant total allocation factor.

4 **Q. PLEASE EXPLAIN HOW KENTUCKY POWER'S FEDERAL AND STATE**  
5 **INCOME TAXES WERE ALLOCATED.**

6 A. For details on Federal and State income taxes, please see Company Witness Hodgson's  
7 Direct Testimony and supporting tax schedules.

8 **Q. PLEASE EXPLAIN HOW ADJUSTMENTS FOR KENTUCKY POWER'S**  
9 **TEST YEAR REVENUES AND OPERATING EXPENSES WERE**  
10 **INCORPORATED INTO SECTION V.**

11 A. Adjustments to test year revenues and operating expenses were provided to me by way  
12 of individual worksheets compiled and prepared by various Company witnesses based  
13 on their expertise. These adjustments can be seen in Section V, Schedule 5 and also in  
14 total on Section V, Schedule 4 under "Going Level Adjustments." I added the retail  
15 adjustments to the Company's retail per books cost-of-service amounts to arrive at the  
16 going-level Kentucky Power jurisdictional cost-of-service as shown on Section V,  
17 Schedule 4 column "Adjusted KY PSC Juris." All methodology and adjustment  
18 worksheets can be seen in Section V, Exhibit 2.

19 **Q. PLEASE EXPLAIN ANY DIFFERENCES IN PRESENTATION, FROM PAST**  
20 **FILINGS, IN THE FORMAT OF THE COMPANY'S JURISDICTIONAL**  
21 **COST-OF-SERVICE STUDY.**

22 A. There are no differences in the format of the Company's jurisdictional cost-of-service  
23 study.

1 **Q. WERE THERE ANY DIFFERENCES IN THE METHODOLOGY USED TO**  
2 **CALCULATE THE REVENUE REQUIREMENT IN THIS PROCEEDING?**

3 A. No.

4 **Q. PLEASE EXPLAIN THE DECISION TO USE RATE BASE INSTEAD OF**  
5 **CAPITALIZATION.**

6 A. Prior to the Company's 2023 base rate case, the revenue requirement had historically  
7 been calculated utilizing a return on Capitalization methodology. In this case, the  
8 Company calculated the base rate revenue requirement utilizing a return on rate base  
9 instead of capitalization consistent with the January 13, 2021 Order in Case  
10 No. 2020-00174.

11 **Q. DESPITE UTILIZING RATE BASE FOR CALCULATING THE REVENUE**  
12 **REQUIREMENT, HAVE YOU CONTINUED TO PREPARE AN ADJUSTED**  
13 **LEVEL OF CAPITALIZATION?**

14 A. Yes. Section V, Schedule 3 presents adjusted Capitalization for comparison's sake, as  
15 well as to establish the debt-to-equity ratios as utilized in determining the weighted  
16 average cost of capital.

## **VI. REVENUE AND OPERATING EXPENSE ADJUSTMENTS**

17 **Q. PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND**  
18 **OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.**

19 A. The details of the revenue and operating expense adjustments are set forth on various  
20 pages of Section V, Exhibit 2 to the application. Specifically, I am sponsoring the  
21 Adjustment to Remove Wholesale Customer Load from the Test Year (W18).

**VII. REMOVAL OF WHOLESALE CUSTOMER LOAD**

1 **Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO REMOVE THE**  
2 **WHOLESALE CUSTOMER LOAD FROM THE TEST YEAR (W18).**

3 A. Following the discontinuation of wholesale customers Olive Hill and Vanceburg, as  
4 discussed by Company Witness Wolffram, it was necessary to allocate these costs for  
5 the historic test year but to then adjust Kentucky Power Retail Per Books to reflect a  
6 true 100% retail share of Kentucky Power Total Company on a going-forward basis.  
7 This adjustment resulted in a Total Net Income Impact of (\$4.6 million) and a total  
8 Rate Base increase of \$18.2 million.

**VIII. CONCLUSION**

9 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.**

10 A. The jurisdictional cost-of-service study, found within Section V, Schedule 4, has been  
11 developed in accordance with sound cost-of-service principles and is consistent with  
12 previously accepted methodologies by the Commission. The results from this study  
13 were used as a basis for the class cost-of-service study as described by Company  
14 Witness Coon.

15 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

16 A. Yes.

## 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

State of Ohio )  
 )  
County of Franklin )

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jaclyn N. Cost, on 08/26/2025.

Brett E. Schmied  
Notary Public

My Commission Expires N/A

Notary ID Number \_\_\_\_\_



BRETT E. SCHMIED, Attorney At Law  
NOTARY PUBLIC - STATE OF OHIO  
My commission has no expiration date  
Sec. 147.03 R.C.

**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 Certain Regulatory And Accounting    )  
Treatments; and (4) All Other Required Approvals    )  
And Relief                                                        )

Case No. 2025-00257

**DIRECT TESTIMONY OF**  
  
**NICOLE M. COON**  
  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
NICOLE M. COON ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT NMC-1	Class Cost-of-Service Study
EXHIBIT NMC-2	Revenue Allocation
EXHIBIT NMC-3	Class Cost-of-Service Allocators

**DIRECT TESTIMONY OF  
NICOLE M. COON ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.     My name is Nicole M. Coon. My business address is 1 Riverside Plaza, Columbus,  
3           Ohio 43215. I am employed by American Electric Power Service Corporation  
4           (“AEPSC”) as a Regulatory Consultant Principal. AEPSC is a wholly-owned  
5           subsidiary of American Electric Power Company Inc. (“AEP”), the parent Company of  
6           Kentucky Power Company (“Kentucky Power” or the “Company”).

**II. BACKGROUND**

7   **Q.     PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
8   **PROFESSIONAL EXPERIENCE.**

9   A.     I graduated from The Ohio State University in 2018 with a Bachelor of Science degree  
10          in Business Administration majoring in Accounting and minoring in Communications.  
11          I obtained my Certified Public Accountant license in 2018 and am licensed in the state  
12          of Ohio. Prior to joining AEPSC, I worked for a regional public accounting firm where  
13          I performed various financial audits of companies and prepared tax returns for  
14          individuals and businesses. In 2019, I joined AEPSC as a Strategic Initiatives Associate  
15          in the Strategy and Transformation Operations Group. I later became a Strategic  
16          Initiatives Associate Senior, where I was responsible for internal and external business

1 valuation, preparing pro forma business and financial plans, performing strategic  
2 studies and analyses, and preparing executive council and board-level presentations. In  
3 2022, I transferred to Regulatory Services to my current position as a Regulatory  
4 Consultant Principal.

5 **Q. WHAT ARE YOUR RESPONSIBILITIES AS REGULATORY CONSULTANT**  
6 **PRINCIPAL?**

7 A. I am responsible for assisting Kentucky Power and the other AEP operating companies  
8 in the preparation of their regulatory filings before this and other Commissions under  
9 whose jurisdiction these companies provide electric service. My responsibilities  
10 include the preparation of cost-of-service analyses, rate design, special contracts, and  
11 economic analyses for the AEP operating companies.

12 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
13 **PROCEEDINGS?**

14 A. Yes. I submitted testimony before the Public Service Commission of Kentucky (the  
15 “Commission”) in Case No. 2024-00243. I have also submitted testimony before the  
16 State Corporation Commission of Virginia on behalf of Appalachian Power Company  
17 in Case Nos. PUR-2023-00212, PUR-2024-00161, and PUR-2025-00028.

### **III. PURPOSE OF TESTIMONY**

18 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
19 **PROCEEDING?**

20 A. The purpose of my Direct Testimony is to support and describe the development of the  
21 Company’s class cost-of-service study. In addition, I will address the allocation of the  
22 requested increase to Kentucky Power’s customer classes.



1   **Q.    ARE YOU SPONSORING ANY EXHIBITS?**

2   A.    I am sponsoring the following exhibits:

3               Exhibit NMC-1       Class Cost-of-Service Study

4               Exhibit NMC-2       Revenue Allocation

5               Exhibit NMC-3       Class Cost-of-Service Allocators

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

8   A.    Yes.

**IV.   CLASS COST-OF-SERVICE STUDY**

9   **Q.    PLEASE DESCRIBE THE GENERAL PURPOSE OF A CLASS COST-OF-**  
10       **SERVICE STUDY.**

11   A.    A class cost-of-service study is a basic analytical tool used in traditional utility rate  
12       design to determine the revenue requirement for the services offered by the utility. It  
13       analyzes, at a very detailed level, the costs that different classes of customers impose  
14       on the utility system. A class cost-of-service study calculates the total functional costs  
15       the Company incurs in serving each retail rate class as well as the rate of return on rate  
16       base earned from each class during the test year. This is accomplished by classifying  
17       and allocating the jurisdictional and functionalized costs of serving Kentucky's retail  
18       customers to the various rate classes. When a cost-of-service study is completed and  
19       all of the costs are allocated to the customer classes, the Company is able to establish  
20       rates based on the costs to serve each customer class. A copy of the class cost-of-service  
21       study prepared for this case is included as Exhibit NMC-1.

1   **Q.     WHAT DATA SOURCE WAS USED IN THE DEVELOPMENT OF THE**  
2       **CLASS COST-OF-SERVICE STUDY?**

3   A.     The Company's jurisdictional cost-of-service study, shown in Section V, Schedule 4  
4       and Schedule 5 of this application and sponsored by Company Witness Cost, is the  
5       primary data source for the class cost-of-service study. In addition, historic accounting  
6       records and Company data were used to derive the various allocators that were applied  
7       to the results of the jurisdictional cost-of-service study to classify and allocate costs to  
8       the customer classes.

9   **Q.     AFTER THE COSTS PRESENTED IN THE JURISDICTIONAL COST-OF-**  
10       **SERVICE STUDY ARE EXAMINED, HOW ARE THESE COSTS ASSIGNED**  
11       **TO EACH CUSTOMER CLASS?**

12   A.     These costs are assigned to the different customer classes in a way that reflects the costs  
13       of providing utility service to each class. The Company assigns costs to customer  
14       classes using a standard three-step process: functionalization of costs, classification of  
15       costs, and allocation of costs.

16   **Q.     PLEASE EXPLAIN THE FUNCTIONALIZATION PROCESS.**

17   A.     Functionalization is the process of separating costs according to electric system  
18       functions. Typically, functions in an electric utility include the following:

- 19           1)     Production and Purchased Power costs;
- 20           2)     Transmission costs;
- 21           3)     Distribution costs;
- 22           4)     Customer Service costs; and
- 23           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:

<u>Function</u>	<u>Classification</u>
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,

1 transmission or distribution facilities, such as a generating unit or transmission and  
2 distribution poles and lines.

3 Energy costs vary with the number of kilowatt-hours (“kWh”) used by the  
4 customer. Production costs such as fuel and certain production operation and  
5 maintenance expenses are energy-related since they vary with the level of sales of  
6 electricity.

7 Customer costs are directly related to the number of customers served. These  
8 are fixed costs which are incurred regardless of the level of energy sales. Meter and  
9 customer service costs are examples of costs whose levels are fixed by the number of  
10 customers.

11 The classification process provides a basis on which to allocate different  
12 categories of costs (demand, energy, or customer) to the Company’s classes. A&G  
13 costs are not classified but are generally allocated to the remaining functions based on  
14 labor.

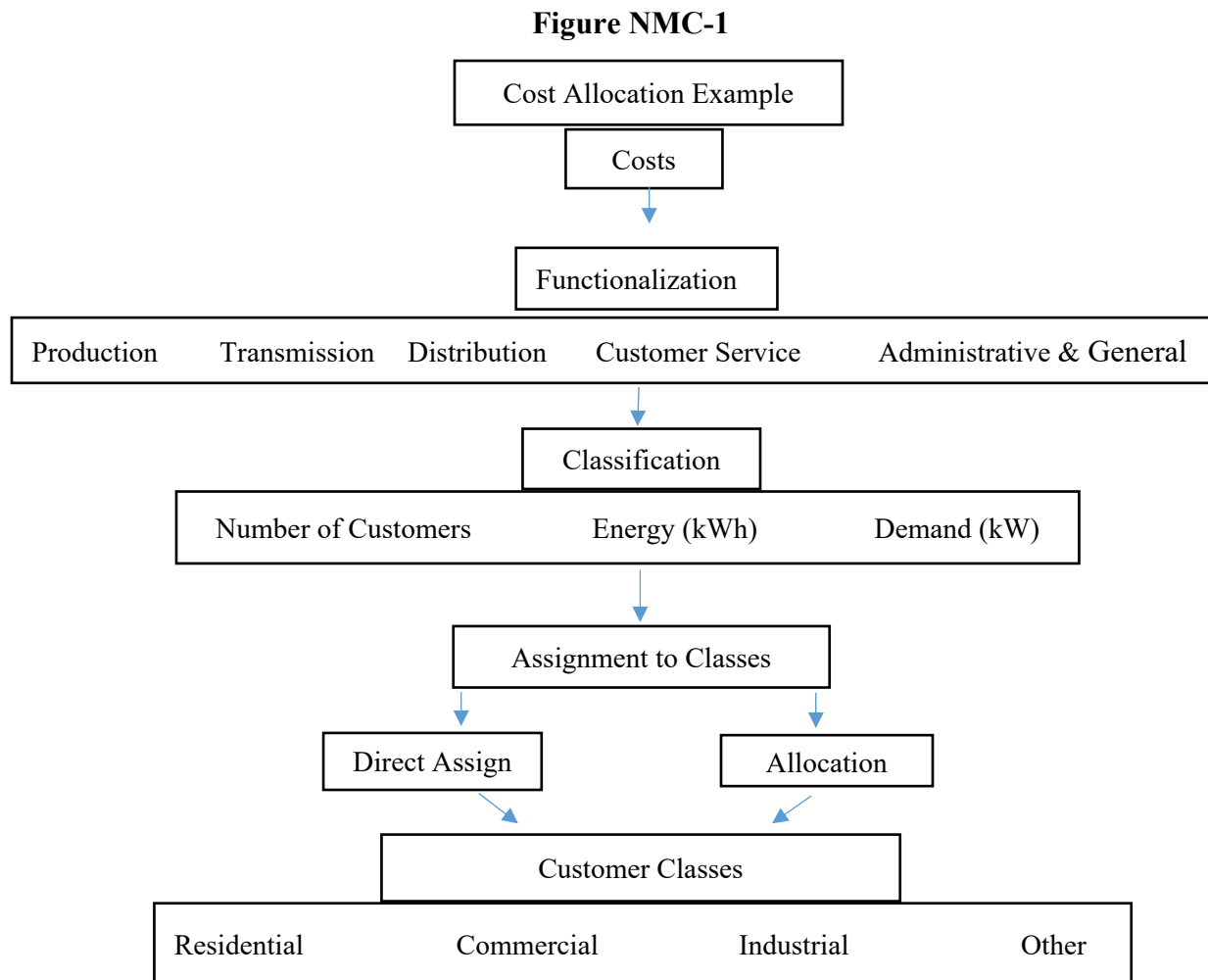
15 **Q. PLEASE EXPLAIN THE ALLOCATION PROCESS.**

16 A. The third and final step is to allocate the functionalized and classified costs among the  
17 classes of customers based on how the costs are incurred to serve each class. Allocation  
18 factors are used to assign these costs to the various customer classes. Customer classes  
19 are determined and grouped according to the nature of service provided, voltage level,  
20 and the load usage characteristics. The three principal customer classes are residential,  
21 commercial, and industrial.

22 The allocation process involves multiplying the functionalized and classified  
23 costs by allocation factors, which results in costs assigned to each class. The objective

1 in this process is to determine a reasonable, appropriate, and supported method to  
 2 assign the costs. Some costs are directly assignable to a single class, or even a single  
 3 customer. For instance, the costs associated with the poles and luminaries used for  
 4 street lighting are directly assigned to the street lighting class. Most costs, however, are  
 5 attributable to more than one type of customer. These are joint costs that are allocated  
 6 to customers by an allocation methodology that is based on the manner in which the  
 7 costs are caused by the different customers.

8 The following flowchart (Figure NMC-1) provides an overview of how the  
 9 allocation of costs to customer classes is determined.



1           In the illustration above, costs are functionalized into production, transmission,  
2           distribution, etc. Some of these costs can be functionalized and classified and directly  
3           assigned to a customer class. The remaining functionalized costs are incurred based on  
4           the number of customers, the energy used, or the capacity demanded.

5           After functionalization, the next step is the classification process which leads  
6           to an allocation methodology. For example, the cost of billing customers varies with  
7           the number of customers as well as the complexity of preparing the customer's bill, so  
8           those costs associated with billing are allocated to the customer classes based on a  
9           weighted number of customers. An allocation factor using a weighted number of  
10          customers is developed by multiplying the number of customers in each class by a  
11          factor representing the difference in cost associated with providing that service to each  
12          customer class. Similarly, the cost of fuel varies by the number of kWh consumed and,  
13          therefore, is allocated based on the proportion of total energy used by a customer class.

14          The final step in the cost assignment process is to allocate the functionalized  
15          and classified costs to the customer classes using allocation factors.

16          When this process is completed and all the costs from Section V, Schedules 4  
17          and 5 are allocated to the customer classes, the result is a fully allocated cost study that  
18          establishes cost responsibility, by class, and makes it possible to determine rates based  
19          on costs that are just and reasonable.

## **V. ALLOCATION BASIS**

1 **Q. WHAT CRITERIA ARE USED WHEN SELECTING ALLOCATION**  
2 **FACTORS FOR EACH FUNCTIONALIZED AND CLASSIFIED COST?**

3 A. Generally, the following criteria are used to determine the appropriateness of an  
4 allocation methodology:

- 5 1) The method should reflect the planning and operating characteristics of  
6 the utility's system.
- 7 2) The method should recognize customer class characteristics such as  
8 energy usage, peak demand on the system, diversity characteristics,  
9 number of customers, etc.
- 10 3) The method should produce stable results on a year-to-year basis.
- 11 4) The method should cause customers who benefit from the use of the  
12 system to bear appropriate cost responsibility for the system.

13 **Q. DOES THE ALLOCATION METHOD EMPLOYED BY THE COMPANY**  
14 **MEET THESE OBJECTIVES?**

15 A. Yes. The allocation methodology utilized in the Company's class cost-of-service study  
16 is generally consistent with prior cases and reflects the consideration of each of the  
17 criteria listed above and the zero-intercept study sponsored by Company Witness  
18 J. Wolfram for allocation of distribution costs. The results of the cost-of-service study  
19 can be relied upon to determine the appropriate revenue requirement for the Kentucky  
20 Power customer classes. The details concerning the allocation of specific sections of  
21 the class cost-of-service study, as shown in Exhibit NMC-1, follows. Exhibit NMC-3  
22 also provides a condensed version of the explanations below for ease of reference.

1   **Q.     PLEASE EXPLAIN THE ALLOCATION OF PRODUCTION PLANT.**

2   A.     The accounts that comprise electric plant-in-service are functionalized into production,  
3           transmission, distribution and general plant. Production plant is classified as  
4           demand-related and allocated using the production demand allocation factor. The  
5           production demand allocation factor assigns costs to the retail classes based on their  
6           average contribution to Kentucky Power's 12 coincident peaks ("CPs"). The CPs used  
7           in the allocation of production plant were the 12 monthly internal peak demands for the  
8           test period ended May 31, 2025.

9   **Q.     PLEASE EXPLAIN HOW GENERATOR STEP-UP TRANSFORMERS**  
10       **WERE ALLOCATED.**

11  A.     Generator step-up transformers are included in transmission plant but were allocated  
12           using the production demand allocation factor because they are more related to the  
13           production function.

14  **Q.     PLEASE EXPLAIN THE ALLOCATION OF TRANSMISSION PLANT.**

15  A.     Transmission plant, excluding generator step-up transformers, is classified as  
16           demand-related and is allocated using the transmission demand allocation factor. The  
17           transmission demand allocation factor, similar to the production plant allocation factor,  
18           assigns costs based on the class average contribution to Kentucky Power's 12 CPs on  
19           the transmission facilities.

20  **Q.     PLEASE EXPLAIN THE ALLOCATION OF DISTRIBUTION PLANT.**

21  A.     Distribution plant is classified as demand-/customer-related and allocated to the  
22           customer classes using factors based on demand levels or number of customers.  
23           Distribution plant accounts 360 through 363 were classified solely as demand-related.



1 Accounts 360, 361, 362, and 363 were allocated to the distribution customer classes  
2 based on their contributions to the average of Kentucky Power's 12 monthly CP  
3 demands during the test year on the primary distribution system.

4 Accounts 364 through 368 were classified as demand and customer-related per  
5 the recommendation of Company Witness J. Wolfram following the results of the  
6 zero-intercept study as described in his Direct Testimony. The demand and  
7 customer-related percentages were derived from the results of the zero-intercept study.  
8 The demand-related percentages were further split into primary and secondary voltage  
9 functions based upon information contained in the zero-intercept study. The  
10 demand-related primary portions of accounts 364 through 368 were allocated using the  
11 average of 12 monthly CP demands on the distribution system. The demand-related  
12 secondary component of accounts 364 through 368 were allocated based on a  
13 combination of each class's 12-month maximum demand and the summation of  
14 individual customers' annual maximum demands in each class served from those  
15 facilities. This process reflects the fact that some secondary facilities serve only one  
16 customer, while others serve two or more customers.

17 Services, account 369, was classified as customer-related and was allocated  
18 using the average number of secondary customers served.

19 Meter plant, account 370, was allocated using the average number of customers  
20 weighted by a factor which considers the cost differential of various metering  
21 installations. Account 371 was directly assigned to the outdoor lighting class and  
22 account 373 was directly assigned to the street lighting class.

1   **Q.     PLEASE EXPLAIN HOW GENERAL AND INTANGIBLE PLANT WAS**  
2       **ALLOCATED.**

3   A.     General and intangible plant and investment reflects a composite demand, energy, and  
4       customer classification. General and intangible plant investment is allocated consistent  
5       with payroll labor.

6   **Q.     PLEASE DESCRIBE THE ALLOCATION OF ACCUMULATED**  
7       **PROVISION FOR DEPRECIATION AND AMORTIZATION.**

8   A.     The functionalized components of Depreciation and Amortization were obtained  
9       directly from the jurisdictional cost-of-service study provided in Section V, Schedule  
10      4 of the application. Production-, transmission-, distribution-, and general and  
11      intangible-related amounts were classified and allocated based upon the allocation of  
12      the corresponding functional Electric Plant-in-Service costs excluding land and land  
13      rights.

14  **Q.     PLEASE DESCRIBE THE ALLOCATION OF WORKING CAPITAL.**

15  A.     Working Capital was divided into cash, material and supplies, and prepayments. Cash  
16      working capital is related to operation and maintenance (“O&M”) expense and was  
17      allocated based upon the allocation of total O&M expense less purchased power and  
18      fuel.

19           Materials and supplies were split between fuel stock, production, emissions,  
20      and transmission and distribution, and were then classified and allocated using the  
21      corresponding functional plant items. Fuel stock and emissions materials were  
22      allocated using the energy allocation factor. Production-related material and supplies  
23      were allocated using the production demand allocation factor, and the

1 transmission- and distribution-related materials and supplies were allocated using the  
2 allocation of transmission and distribution electric plant-in-service.

3 Prepayments were allocated based upon gross utility plant.

4 **Q. PLEASE DESCRIBE THE ALLOCATION OF OTHER RATE BASE**  
5 **COMPONENTS.**

6 A. Plant Held for Future Use is limited to a distribution component that was allocated  
7 using distribution electric plant-in-service. Construction Work-in-Progress was  
8 functionalized and allocated by the corresponding functional Electric Plant-in-Service  
9 allocators. Accumulated Deferred Federal Income Tax was allocated on gross utility  
10 plant. Customer Advances were allocated based on transmission and distribution plant-  
11 in-service and Customer Deposits were directly assigned based on an analysis of  
12 accounting records.

13 **Q. HOW WERE REVENUES DEVELOPED FOR EACH CLASS?**

14 A. Sales revenues were directly assigned to each class utilizing the revenue schedules  
15 in Section II – Application Filing Requirements Exhibit J, sponsored by  
16 Company Witness Spaeth. Energy-related system sales revenue was allocated using  
17 the energy allocation factor.

18 Forfeited Discounts and Miscellaneous Service Revenue were directly assigned  
19 based on an analysis of accounting records.

20 Rent from Electric Property and Other Electric Revenue were functionalized in  
21 the jurisdictional cost-of-service study, found in Section V, Schedule 4, and allocated  
22 to classes based on corresponding functional allocators.

1   **Q.   PLEASE DESCRIBE THE ALLOCATION OF PRODUCTION O&M**  
2       **EXPENSE.**

3   A.   Production-related O&M was classified as either demand- or energy-related. The  
4       demand component was allocated using the production demand allocation factor and  
5       the energy component was allocated using the energy allocation factor. Supervision  
6       and Engineering accounts for both O&M were classified and allocated based on  
7       functional labor expense. For example, Accounts 500 and 510 for Steam Production  
8       accounts were allocated on production labor expense.

9   **Q.   PLEASE DESCRIBE THE ALLOCATION OF TRANSMISSION O&M.**

10  A.   Transmission-related O&M was broken down into two pieces: expenses incurred  
11       through PJM as a Load Serving Entity (“LSE”), and the traditional transmission cost-  
12       of-service expenses recorded in FERC accounts 560–575. Most Transmission O&M  
13       expenses were allocated based upon the transmission demand allocation factor.  
14       Supervision and Engineering accounts for both O&M were classified and allocated  
15       based on functional labor expense. For example, Transmission Accounts 560 and 568  
16       were allocated on total transmission O&M excluding PJM-related costs. Expenses  
17       incurred through PJM as an LSE are classified as production expenses as they capture  
18       load LSE charges and are allocated using an allocation factor based on production  
19       demand.

20  **Q.   PLEASE DESCRIBE THE ALLOCATION OF DISTRIBUTION O&M**  
21       **AMONG THE VARIOUS CUSTOMER CLASSES.**

22  A.   Distribution O&M expenses were functionalized and classified according to the  
23       associated distribution plant accounts and allocated accordingly. Accounts 581 Load

1       Dispatching and 582 Station Expenses were allocated using the distribution demand  
2       allocation factor. Account 583 Overhead Line Expense was allocated based upon the  
3       same allocation used for plant account 365 Overhead Lines. Account 584 Underground  
4       Line Expense was allocated based upon the same allocation used for plant accounts  
5       366 Underground Conduit and 367 Underground Lines. Account 585 Street Lighting  
6       Operation Expense was classified as customer-related and directly assigned to the  
7       Street Lighting class. Meter Operation Expense, account 586, was classified  
8       customer-related and allocated in the same manner as account 370 Meter Plant.  
9       Account 587 Customer Installation Expense was classified as customer-related and  
10      allocated based on primary customers. Accounts 588 and 589 were allocated on total  
11      distribution plant and classified accordingly. Account 580 was classified and allocated  
12      based on the sum of the allocated O&M expense accounts 581–589. Accounts 591 and  
13      592 were classified demand-related and allocated on the distribution demand allocation  
14      factor. Accounts 593, 594, and 595 were functionalized and classified according to the  
15      associated distribution plant accounts and allocated accordingly. Distribution  
16      maintenance account 596 was directly assigned to the Street Lighting class. Account  
17      597 was classified as customer-related and allocated in the same manner as meter plant.  
18      Account 598 was classified customer-related and directly assigned to the Outdoor  
19      Lighting class. Account 590 was classified and allocated based on the sum of the  
20      allocated O&M expense accounts 591–598.

1   **Q.     CAN YOU EXPLAIN HOW CUSTOMER ACCOUNTING (ACCOUNTS**  
2       **901–905), CUSTOMER SERVICES (ACCOUNTS 907–910), AND SALES**  
3       **EXPENSE (ACCOUNTS 911–916) WERE ALLOCATED?**

4   A.    Account 902 Meter Reading Expense was allocated to those classes with meter  
5       installations based upon an average number of customers weighted to reflect varying  
6       levels of difficulty in meter reading. Account 903 Customer Records Expense was  
7       divided into two categories of cost: call center and other. Call center costs were first  
8       divided into residential and other based on the number of calls received; then, other  
9       (non-residential) call center expenses were further allocated to the remaining  
10      non-residential classes based on the number of customers in each respective class.  
11      Account 904 Uncollectibles was allocated based on the number of customers. Accounts  
12      901 and 905 were allocated based on the sum of the allocated accounts 902, 903, and  
13      904.

14           Accounts 907 through 916, Customer Service Expenses and Sales Expenses,  
15      were allocated based on the number of customers.

16   **Q.     PLEASE DESCRIBE THE ALLOCATION OF A&G EXPENSE.**

17   A.    A&G expenses, excluding Property Insurance, account 924, and Rate Case Expense,  
18       account 928, were functionalized, classified, and allocated using O&M labor. Property  
19       Insurance was allocated using gross utility plant. Rate Case Expense was allocated to  
20       the customer classes based on sales revenue.

1 **Q. PLEASE DESCRIBE THE ALLOCATION OF DEPRECIATION AND**  
2 **AMORTIZATION EXPENSE.**

3 A. The functionalized components of depreciation and amortization expense were  
4 allocated using the corresponding functional plant items excluding land and land rights.

5 **Q. PLEASE DESCRIBE HOW OTHER EXPENSES WERE ALLOCATED.**

6 A. The Gain on Disposition of Utility Plant was allocated based on distribution plant.  
7 Accounts Receivable Factoring was allocated based on gross utility plant. Gain/Loss  
8 on Disposition of Allowances was allocated based on the energy allocation factor.  
9 Accretion was allocated on production demand. The Interest Income and Interest  
10 Expense items were allocated based on gross utility plant. Interest on Customer  
11 Deposits was allocated using the customer deposit allocator that was also used for the  
12 customer deposit rate base offset.

13 **Q. HOW WERE TAXES ASSIGNED TO THE CUSTOMER CLASSES?**

14 A. Individual tax items other than income taxes were allocated and classified using the  
15 appropriate revenue, labor, or plant allocator.

16 Interest Expense was allocated on rate base, and individual Schedule M<sup>1</sup> items  
17 were allocated using the appropriate allocators. State and current Federal Income Taxes  
18 were computed by class. Feedback of prior Investment Tax Credit Normalized was  
19 allocated based on gross utility plant and individual Deferred Federal Income Tax items  
20 were allocated using the appropriate allocation factors.

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<sup>1</sup> Schedule M items were sourced from Section V, Exhibit 3 of the Company's Application.

1   **Q.     PLEASE DESCRIBE THE ALLOCATION OF THE ALLOWANCE FOR**  
2       **FUNDS USED DURING CONSTRUCTION (“AFUDC”) OFFSET.**

3   A.    The AFUDC offset was divided into the individual functionalized components in the  
4       jurisdictional cost-of-service study. The production component was allocated using the  
5       production demand allocator. The transmission and distribution components were  
6       allocated using the corresponding plant allocators. The general plant component was  
7       allocated using the labor allocation factor.

8   **Q.     PLEASE   DESCRIBE   THE   ALLOCATION   OF   THE   VARIOUS**  
9       **JURISDICTIONAL ADJUSTMENTS.**

10  A.    The jurisdictional adjustments are identified in the various sections of the  
11       cost-of-service study to which they apply. Each adjustment was allocated using a  
12       method consistent with both the nature of the adjustment and the underlying line item  
13       being adjusted. For example, an adjustment to employee-related expenses is allocated  
14       using the labor allocation factor, and an adjustment to Electric plant in-service for the  
15       Turbine Reservation Fee, as supported by Company Witness Wolfram, is allocated  
16       using the production demand allocation factor.

## VI.   REVENUE ALLOCATION

17  **Q.     WHAT IS THE RESULTING GOING-LEVEL AND RELATIVE RATE OF**  
18       **RETURN FOR EACH CLASS SHOWN IN THE CLASS COST-OF-SERVICE**  
19       **STUDY?**

20  A.    The resulting going-level rates of return (“ROR”) and relative rates of return prior to  
21       the rate relief requested in this case, for each customer class as shown in the class  
22       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 NMC-2- Class Going-Level Rates of Return and Relative Rates of Return and Current Subsidy**

<b>Class</b>	<b>Going-Level ROR</b>	<b>Relative ROR</b>	<b>Subsidy (Paid)/ Received (\$ in Millions)</b>
Residential	2.05%	0.45	\$36.3
General Service	8.66%	1.89	(\$14.9)
Large General Service	14.52%	3.18	(\$17.4)
Industrial General Service	4.52%	0.99	\$0.3
Municipal Waterworks	16.36%	3.58	(\$0.07)
Outdoor Lighting	14.08%	3.08	(\$3.5)
Street Lighting	17.58%	3.85	(\$0.8)
Total Kentucky Power Jurisdiction	4.57%	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

1 provided to Company Witness Wolffram and Company Witness Newcomb to assist in  
2 the Company's determination of the allocation of the requested rate increase by class.

3 **Q. PLEASE EXPLAIN THE PRINCIPLES OR GUIDELINES USED IN**  
4 **ALLOCATING THE PROPOSED REVENUE INCREASE AMONG THE**  
5 **TARIFF CLASSES.**

6 A. A key objective of ratemaking is to design rates such that they reflect as nearly as  
7 possible the actual costs of serving the customer. To fully meet this objective would  
8 require that the rates of return for all tariff classes be equalized. However, this would  
9 result in significant bill impacts to the residential customer class. As a result, the  
10 Company opted not to propose to fully equalize returns across tariff classes at this time,  
11 but rather mitigate the rate increase to residential customers by capping all customer  
12 classes' percentage increase to 15%. This mitigation strategy is supported by Company  
13 Witness Wolffram.

14 **Q. PLEASE DESCRIBE EXHIBIT NMC-2.**

15 A. Exhibit NMC-2 is the calculation of the allocation of the proposed revenue increase to  
16 each class of customers. Page 1 is a summary of the calculation of the required sales  
17 revenue per class based upon the Company's proposed subsidy reduction. Page 2 of the  
18 exhibit calculates the current subsidies received by each class. Page 3, in Columns 2  
19 through 11, shows the calculation of the required sales revenue at an equalized ROR  
20 for each class before demonstrating in Columns 12 and 13 what the base rate revenue  
21 increase would be from just keeping 100% of the current subsidy. Columns 15 and 16  
22 shows the proposed base rate revenue with the mitigation strategy in place, which is  
23 the ultimate proposal from the Company in this case.

1 **Q. WHAT CLASS-BY-CLASS BASE RATE REVENUE INCREASE WILL**  
 2 **RESULT FROM THE PROPOSED INCREASE?**

3 A. Figure NMC-3 summarizes the Company's proposed revenue allocation, as sponsored  
 4 by Company Witness Wolfram, between the major customer classes and the class rate  
 5 increases:

**Figure NMC-3- Base Rate Increase**

<b>Class</b>	<b>Proposed Base Increase (\$ in Millions)</b>	<b>Percent Base Increase</b>
Residential	\$33.2	12.29%
General Service	\$12.1	12.66%
Large General Service	\$7.8	12.69%
Industrial General Service	\$20.9	13.11%
Municipal Waterworks	\$0.03	12.55%
Outdoor Lighting	\$1.1	12.56%
Street Lighting	\$0.2	12.26%
Total Kentucky Power Jurisdiction	\$75.3	12.61%

## **VII. CONCLUSION**

6 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.**

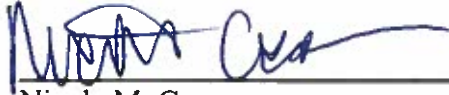
7 A. The class cost-of-service study, Exhibit NMC-1, has been developed in accordance  
 8 with sound cost-of-service principles. The class cost-of-service study, along with the  
 9 revenue allocation, submitted as Exhibit NMC-2, provide Company Witness Spaeth  
 10 with functionalized revenue requirements that he can use to develop rates for the  
 11 Company's customer classes.

1    **Q.     DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2    **A.     Yes, it does.**

## VERIFICATION

The undersigned, Nicole M. Coon, being duly sworn, deposes and says she is a Regulatory Consultant Principal 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.



Nicole M. Coon

State of Ohio

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Nicole M. Coon, on 8/20/2025

  
Notary Public

My Commission Expires

Never

Notary ID Number

No ID



Paul D. Flory  
Attorney At Law  
Notary Public, State of Ohio  
My commission has no expiration date  
Sec. 147.03 R.C.

Exhibit No.: NMC-1  
Page 1 of 30  
Witness: N. Coon

Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	IGS	PS	MW 16	OL 17	SL 18
Rate Base												
P-T-D Plant in Service												
Production Plant & Comp. Const. not Classif.	1,238,869,244	PROD_DEMAND	TOTAL	1,238,869,244	607,470,759	155,507,336	84,362,100	371,292,346	17,872,968	304,267	1,649,794	409,673
Transmission & Comp. Const. not Classif.												
GSU	12,793,807	PROD_DEMAND	TOTAL	12,793,807	6,273,353	1,605,925	871,208	3,834,337	184,574	3,142	17,037	4,231
All Other Transmission Plant	936,140,223	TRANS_TOTAL	TOTAL	936,140,223	455,022,790	116,860,859	64,122,697	284,958,511	13,582,638	227,459	1,093,565	271,704
Total	948,934,030		TOTAL	948,934,030	461,296,142	118,466,784	64,993,905	288,792,848	13,767,212	230,601	1,110,602	275,935
Distribution & Comp. Const. not Classif.												
360 Land and Land Rights	12,184,440	DIST_CPD	TOTAL	12,184,440	8,096,544	2,062,186	1,128,547	629,996	244,265	4,104	15,045	3,752
361 Structures and Improvements	19,882,579	DIST_CPD	TOTAL	19,882,579	13,211,947	3,365,078	1,841,564	1,028,029	398,592	6,697	24,550	6,122
362 Station Equipment	170,244,390	DIST_CPD	TOTAL	170,244,390	113,127,168	28,813,444	15,768,377	8,802,485	3,412,940	57,345	210,208	52,423
363 Storage Battery Equipment	3,211,366	DIST_CPD	TOTAL	3,211,366	2,133,948	543,516	297,443	166,044	64,379	1,082	3,965	989
364 Poles	334,592,649	DIST_OHINES	TOTAL	334,592,649	255,612,437	61,237,215	10,364,742	4,448,835	2,420,928	48,198	312,037	148,257
365 Overhead Lines	350,619,861	DIST_OHINES	TOTAL	350,619,861	267,856,444	64,170,519	10,861,220	4,661,937	2,536,892	50,507	326,984	155,358
366 Underground Conduit	10,274,471	DIST_UGLINES	TOTAL	10,274,471	7,713,214	1,825,578	450,587	141,015	11,159	1,994	23,656	7,288
367 Underground Lines	13,466,387	DIST_UGLINES	TOTAL	13,466,387	10,109,438	2,392,721	590,568	184,824	145,892	2,613	31,005	9,526
368 Transformers	175,015,724	DIST_TRANSF	TOTAL	175,015,724	131,313,629	30,930,120	7,907,880	2,259,676	1,981,020	35,144	453,871	134,385
369 Services	80,135,686	DIST_SERV	TOTAL	80,135,686	50,272,277	11,889,864	140,485	1,930	49,015	3,088	17,758,572	20,455
370 Meters	25,662,185	DIST_METERS	TOTAL	25,662,185	15,765,072	7,240,328	1,315,357	1,174,741	158,690	7,997	-	-
371 Installations on Cust Premises	20,930,435	DIST_OL	TOTAL	20,930,435	-	-	-	-	-	-	20,930,435	-
373 Street Lighting	5,722,632	DIST_SL	TOTAL	5,722,632	-	-	-	-	-	-	-	5,722,632
Total	1,221,942,806		TOTAL	1,221,942,806	875,212,117	214,470,568	50,666,771	23,499,510	11,523,572	218,769	40,090,328	6,261,169
Total P-T-D Plant in Service	3,409,746,080		TOTAL	3,409,746,080	1,943,979,018	488,444,689	200,022,777	683,584,705	43,163,753	753,637	42,850,724	6,946,777
General & Intangible Plant & Comp. Const. not Classif.	166,335,629	LABOR_M	TOTAL	166,335,629	99,536,762	25,146,230	8,424,143	30,097,875	1,821,685	35,582	1,044,264	229,088
HR - J 765 Line - FERC AFUDC Adj.	285,539	BULK_TRANS	TOTAL	285,539	140,012	35,842	19,444	85,577	4,119	70	380	94
Total Electric Plant in Service	3,576,367,248		TOTAL	3,576,367,248	2,043,655,792	513,626,761	208,466,364	713,768,157	44,989,557	789,289	43,895,368	7,175,959
Adj 18 - Wholesale Load - General	3,475,792	LABOR_M	TOTAL	3,475,792	2,079,946	525,462	176,033	628,933	38,066	744	21,821	4,787
Adj 18 - Wholesale Load - Transmission	14,459,958	TRANS_TOTAL	TOTAL	14,459,958	7,028,446	1,805,075	990,462	4,401,572	209,802	3,513	16,892	4,197
Adj 18 - Wholesale Load - Production	18,866,029	PROD_DEMAND	TOTAL	18,866,029	9,250,824	2,368,132	1,284,702	5,654,198	272,177	4,634	25,124	6,239
Adj 49 - Remove Mitchell from Rate base and Cost of Service	(327,699,887)	PROD_DEMAND	TOTAL	(327,699,887)	(160,685,319)	(41,134,072)	(22,315,067)	(98,212,512)	(4,727,674)	(80,483)	(436,396)	(108,365)
Adj 50 -Veg Management Tree Trimming & Dist Investment	18,000,000	DIST_OHINES	TOTAL	18,000,000	13,751,121	3,294,364	557,590	239,333	130,238	2,593	16,787	7,976
Adj 57 - Remove FGD from Base Rates (Mitchell)	(324,570,749)	PROD_DEMAND	TOTAL	(324,570,749)	(159,150,968)	(40,741,291)	(22,101,986)	(97,274,701)	(4,682,530)	(79,715)	(432,229)	(107,330)
Total Adjustments to Electric Plant in Service	(597,468,857)		TOTAL	(597,468,857)	(287,725,951)	(73,882,330)	(41,408,266)	(184,563,177)	(8,759,920)	(148,714)	(788,001)	(192,497)
Total Adjusted Electric Plant in Service	2,978,898,391		TOTAL	2,978,898,391	1,755,929,841	439,744,431	167,058,097	529,204,980	36,229,637	640,574	43,107,367	6,983,463
Depreciation Reserve												
Generation	(621,289,966)	RB_GUP-Land_P	TOTAL	(621,289,966)	(309,736,467)	(79,069,339)	(41,604,728)	(180,856,718)	(8,826,865)	(150,669)	(834,797)	(210,384)
Transmission - GSU	(6,783,304)	RB_GUP-Land_P	TOTAL	(6,783,304)	(3,381,733)	(863,287)	(454,244)	(1,974,611)	(96,373)	(1,645)	(9,114)	(2,297)
Transmission - All Other	(295,322,857)	RB_GUP-Land_T	TOTAL	(295,322,857)	(143,506,689)	(36,859,680)	(20,232,326)	(89,937,955)	(4,285,641)	(71,732)	(343,505)	(85,348)
Distribution	(385,493,205)	RB_GUP-Land_D	TOTAL	(385,493,205)	(276,306,463)	(67,684,270)	(15,788,045)	(7,289,052)	(3,594,713)	(68,411)	(12,768,545)	(1,993,706)
General & Intangible	(65,951,407)	RB_GUP-Land_G	TOTAL	(65,951,407)	(39,465,925)	(9,970,379)	(3,340,139)	(11,933,886)	(722,291)	(14,108)	(414,046)	(90,832)
HR-J Post In-Service AFUDC	(1,332,727)	BULK_TRANS	TOTAL	(1,332,727)	(653,493)	(167,289)	(90,753)	(399,422)	(19,227)	(327)	(1,775)	(441)
Total Depreciation Reserve	(1,376,173,466)		TOTAL	(1,376,173,466)	(773,050,751)	(194,614,242)	(81,510,236)	(292,391,444)	(17,545,109)	(306,893)	(14,371,783)	(2,383,008)
Adj 18 - Wholesale Load - Distribution	385,879	DIST_OHINES	TOTAL	385,879	294,793	70,624	11,953	5,131	2,792	56	360	171
Adj 18 - Wholesale Load - Transmission	4,600,602	TRANS_TOTAL	TOTAL	4,600,602	2,236,181	574,305	315,127	1,400,410	66,751	1,118	5,374	1,335
Adj 18 - Wholesale Load - Production	9,597,532	PROD_DEMAND	TOTAL	9,597,532	4,706,082	1,204,717	653,554	2,876,405	138,462	2,357	12,781	3,174
Adj 49 - Remove Mitchell from Rate base and Cost of Service	(200,045,017)	PROD_DEMAND	TOTAL	(200,045,017)	(98,090,657)	(25,110,372)	(13,622,275)	(59,954,014)	(2,886,017)	(49,131)	(266,399)	(66,152)
Adj 57 - Remove FGD from Base Rates (Mitchell)	(166,612,406)	PROD_DEMAND	TOTAL	(166,612,406)	(81,697,213)	(20,913,790)	(11,345,647)	(49,934,713)	(2,403,691)	(40,920)	(221,877)	(55,096)
Total Depreciation Adjustments	(352,073,410)		TOTAL	(352,073,410)	(172,550,815)	(44,174,516)	(23,987,287)	(105,606,240)	(5,081,703)	(86,521)	(469,760)	(116,567)
Total Adjusted Depreciation Reserve	(1,024,100,056)		TOTAL	(1,024,100,056)	(600,499,936)	(150,439,726)	(57,522,949)	(186,785,204)	(12,463,407)	(220,372)	(13,902,023)	(2,266,441)
Net Electric Plant in Service												
Plant Held for Future Use - Transmission	-	RB_GUP_EPIS_T	TOTAL	-	-	-	-	-	-	-	-	-
Plant Held for Future Use - Distribution	801,671	RB_GUP_EPIS_D	TOTAL	801,671	574,194	140,706	33,241	15,417	7,560	144	26,302	4,108
Total Plant Held for Future Use	801,671		TOTAL	801,671	574,194	140,706	33,241	15,417	7,560	144	26,302	4,108

**KENTUCKY POWER COMPANY**  
**COST-OF-SERVICE STUDY**  
**TWELVE MONTHS ENDING**  
**MAY 31, 2025**

Exhibit No.: NMC-1  
Page 2 of 30  
Witness: N. Coon

<u>Label</u>	<u>Constant</u>	<u>Allocation Factor</u>	<u>Function</u>	<u>Total Retail</u> <u>1</u>	<u>RS</u> <u>2</u>	<u>Total GS</u> <u>GS</u>	<u>Total LGS</u> <u>LGS</u>	<u>Total IGS</u> <u>IGS</u>	<u>Total PS</u> <u>PS</u>	<u>MW</u> <u>16</u>	<u>OL</u> <u>17</u>	<u>SL</u> <u>18</u>
Working Capital - Cash												
Working Capital Cash - Excl Sys Sales	(60,772,165)	EXP_OM_LPP	TOTAL	(60,772,165)	(36,756,606)	(8,870,299)	(3,286,264)	(10,870,071)	(697,076)	(12,010)	(228,819)	(51,019)
Total Working Capital - Cash	(60,772,165)		TOTAL	(60,772,165)	(36,756,606)	(8,870,299)	(3,286,264)	(10,870,071)	(697,076)	(12,010)	(228,819)	(51,019)
Cash Working Capital Adjustments												
- PROD_ENERGY			TOTAL	-	-	-	-	-	-	-	-	-
- PROD_ENERGY			TOTAL	-	-	-	-	-	-	-	-	-
- PROD_ENERGY			TOTAL	-	-	-	-	-	-	-	-	-
- PROD_DEMAND			TOTAL	-	-	-	-	-	-	-	-	-
- CUST_TOTAL			TOTAL	-	-	-	-	-	-	-	-	-
- CUST_TOTAL			TOTAL	-	-	-	-	-	-	-	-	-
- RSALE			TOTAL	-	-	-	-	-	-	-	-	-
- RSALE			TOTAL	-	-	-	-	-	-	-	-	-
- RSALE			TOTAL	-	-	-	-	-	-	-	-	-
- TDOMX			TOTAL	-	-	-	-	-	-	-	-	-
- TDOMX			TOTAL	-	-	-	-	-	-	-	-	-
- RSALE			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- RB_GUP			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- TRAN_LSE			TOTAL	-	-	-	-	-	-	-	-	-
- CUST_TOTAL			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- RB_GUP			TOTAL	-	-	-	-	-	-	-	-	-
- TOTOHLINES			TOTAL	-	-	-	-	-	-	-	-	-
- TDOMX			TOTAL	-	-	-	-	-	-	-	-	-
- CUST_TOTAL			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- TRANS_TOTAL			TOTAL	-	-	-	-	-	-	-	-	-
- RB_GUP_EPIS_D			TOTAL	-	-	-	-	-	-	-	-	-
- LABOR_M			TOTAL	-	-	-	-	-	-	-	-	-
- CUST_903			TOTAL	-	-	-	-	-	-	-	-	-
- PROD_ENERGY			TOTAL	-	-	-	-	-	-	-	-	-
- PROD_ENERGY			TOTAL	-	-	-	-	-	-	-	-	-
- PROD_ENERGY			TOTAL	-	-	-	-	-	-	-	-	-
- RSALE			TOTAL	-	-	-	-	-	-	-	-	-
Total Cash Working Capital Adjustments	-		TOTAL	-	-	-	-	-	-	-	-	-
Working Capital - Materials & Supplies												
Fuel / Allowance Inventory	67,185,885	PROD_ENERGY	TOTAL	67,185,885	24,424,251	7,975,858	4,981,312	28,210,724	1,059,091	23,759	408,831	102,058
Production - Demand Related	12,062,603	PROD_DEMAND	TOTAL	12,062,603	5,914,812	1,514,141	821,416	3,615,194	174,025	2,963	16,064	3,989
Emissions - Energy Related	1,828,457	PROD_ENERGY	TOTAL	1,828,457	664,704	217,062	135,566	767,752	28,823	647	11,126	2,777
Transmission & Distribution	8,695,128	TDPLANT	TOTAL	8,695,128	5,353,044	1,333,500	463,279	1,251,019	101,302	1,800	165,004	26,180
Total Working Cap - Materials & Supplies	89,772,073		TOTAL	89,772,073	36,356,811	11,040,562	6,401,573	33,844,689	1,363,241	29,169	601,025	135,004
Working Capital - Materials & Supplies Adjustments												
Adj 57 - Remove FGD from Base Rates (Mitchell)	(1,025,060)	PROD_ENERGY	TOTAL	(1,025,060)	(372,643)	(121,688)	(76,000)	(430,413)	(16,159)	(362)	(6,238)	(1,557)
Adj 18 - Wholesale Load	183,694	PROD_DEMAND	TOTAL	183,694	90,073	23,058	12,509	55,054	2,650	45	245	61
Adj 18 - Wholesale Load	979,920	PROD_ENERGY	TOTAL	979,920	356,233	116,330	72,653	411,459	15,447	347	5,963	1,489
Adj 18 - Wholesale Load	46,253	TDPLANT	TOTAL	46,253	28,475	7,093	2,464	6,655	539	10	678	139
Total Working Cap - Materials & Supplies Adjustments	184,807		TOTAL	184,807	102,139	24,793	11,626	42,754	2,477	39	848	131
Working Capital - Prepayments												
Working Capital - Prepayments	1,403,444	RB_GUP_EPIS	TOTAL	1,403,444	827,269	207,176	78,706	249,324	17,069	302	20,309	3,290
Working Capital - Prepayments Adjustments												
Adj 18 - Wholesale Load	28,642	RB_GUP_EPIS	TOTAL	28,642	16,883	4,228	1,606	5,088	348	6	414	67
Total Working Capital	30,616,801		TOTAL	30,616,801	546,495	2,406,460	3,207,247	23,271,784	686,060	17,505	393,777	87,474
Construction Work-In-Progress excluding AFUDC												
Production	7,043,441	RB_GUP_EPIS_P	TOTAL	7,043,441	3,511,229	896,353	471,691	2,050,538	100,074	1,708	9,464	2,385
Transmission	95,827,012	RB_GUP_EPIS_T	TOTAL	95,827,012	46,583,582	11,963,252	6,563,323	29,163,280	1,390,264	23,287	112,158	27,866
Distribution	52,791,040	RB_GUP_EPIS_D	TOTAL	52,791,040	37,811,392	9,265,675	2,188,934	1,015,239	497,848	9,451	1,732,004	270,498
General	1,473,891	RB_GUP_EPIS_G	TOTAL	1,473,891	881,990	222,819	74,646	266,696	16,142	315	9,253	2,030

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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 CWIP	157,135,384		TOTAL	157,135,384	88,788,193	22,348,098	9,298,594	32,495,753	2,004,327	34,762	1,862,879	302,779
Adjustments to CWIP	1,649,478	RB_GUP_EPIS_P	TOTAL	1,649,478	822,282	209,914	110,464	480,208	23,436	400	2,216	559
Total Adjusted CWIP	158,784,862		TOTAL	158,784,862	89,610,475	22,558,012	9,409,057	32,975,961	2,027,763	35,162	1,865,095	303,338
Rate Base Offsets												
Accumulated Deferred FIT	(339,627,927)	RB_GUP	TOTAL	(339,627,927)	(200,195,755)	(50,135,812)	(19,046,502)	(60,335,321)	(4,130,586)	(73,033)	(4,914,725)	(796,193)
Customer Advances	(1,321,973)	TDPLANT	TOTAL	(1,321,973)	(813,856)	(202,740)	(70,435)	(190,200)	(15,402)	(274)	(25,087)	(3,980)
Customer Deposits	(35,770,430)	CUST_DEP_FXNL	TOTAL	(35,770,430)	(23,746,682)	(5,490,533)	(2,857,530)	(3,521,891)	(26,957)	-	(126,837)	-
Adjustments to Rate Base Offsets												
Adj 52 - Turbine Reservation Fee	10,000,000	PROD_DEMAND	TOTAL	10,000,000	4,903,429	1,255,236	680,960	2,997,026	144,268	2,456	13,317	3,307
Adj 57 - Remove FGD from Base Rates (Mitchell)	44,877,672	PROD_DEMAND	TOTAL	44,877,672	22,005,449	5,633,207	3,055,992	13,449,955	647,443	11,022	59,763	14,840
Adj - Amortization of Excess	9,736,072	RB_GUP	TOTAL	9,736,072	5,738,987	1,437,237	546,004	1,729,625	118,411	2,094	140,890	22,824
Adj - NOLC	44,878,523	RB_GUP	TOTAL	44,878,523	26,453,919	6,624,959	2,516,810	7,972,725	545,817	9,651	649,433	105,209
Adj 18 - Wholesale Load Going Level Adjustment	(5,514,296)	RB_GUP	TOTAL	(5,514,296)	(3,250,435)	(814,019)	(309,244)	(979,621)	(67,065)	(1,186)	(79,797)	(12,927)
Adj - CAMT & NERC	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Total Adjustments to Rate Base Offsets	103,977,971		TOTAL	103,977,971	55,851,349	14,136,620	6,490,522	25,169,710	1,388,874	24,036	783,606	133,253
Total Rate Base Offsets	(272,742,359)		TOTAL	(272,742,359)	(168,904,944)	(41,692,464)	(15,483,946)	(38,877,702)	(2,784,071)	(49,270)	(4,283,042)	(666,920)
Total Rate Base	1,872,259,310		TOTAL	1,872,259,310	1,077,256,125	272,717,418	106,700,748	359,805,237	23,703,542	423,743	27,207,476	4,445,022
Operating Revenues												
Year End Migration Revenue	601,558,147	RSALE	TOTAL	601,558,147	271,946,349	96,450,214	50,044,321	160,602,389	11,756,321	221,665	8,755,836	1,781,053
Adj - Adjustment	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Adj 14 - Year End Customer Annualization	(3,776,112)	REVEEC_FXNL	TOTAL	(3,776,112)	(1,461,995)	(439,438)	(265,005)	(1,434,335)	(125,004)	-	(50,335)	-
Adj 15 - Weather Normalization Adjustment	(1,012,932)	WEATHER_FXNL	TOTAL	(1,012,932)	(343,415)	(430,128)	(200,746)	-	(38,642)	-	-	-
Total Firm Sales	596,769,104		TOTAL	596,769,104	270,140,939	95,580,647	49,578,570	159,168,054	11,592,675	221,665	8,705,501	1,781,053
Non-Firm Sales: Energy	22,287,073	PROD_ENERGY	TOTAL	22,287,073	8,102,075	2,645,772	1,652,414	9,358,133	351,324	7,882	135,618	33,855
Non-Firm Sales: Demand	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 18 - Wholesale Load	316,449	PROD_ENERGY	TOTAL	316,449	115,040	37,567	23,462	132,874	4,988	112	1,926	481
Total Sales of Electricity Adjustments	316,449		TOTAL	316,449	115,040	37,567	23,462	132,874	4,988	112	1,926	481
Sales of Electricity	619,372,626		TOTAL	619,372,626	278,358,053	98,263,986	51,254,446	168,659,062	11,948,988	229,658	8,843,045	1,815,389
Other Operating Revenues												
450-Forfeited Discounts	1,035,102	FORF_DISC_FXNL	TOTAL	1,035,102	109	522,364	221,878	285,965	-	-	4,786	-
451-Miscellaneous Service Revenue	98,240	MISC_SERV_REV	TOTAL	98,240	87,062	9,024	156	20	-	-	1,977	-
454x-Rent from Electric Prop - Poles	5,142,475	DIST_OHNLINES	TOTAL	5,142,475	3,928,600	941,177	159,299	68,376	37,208	741	4,796	2,279
454x-Rent from Electric Prop - Production	2,452,567	RB_GUP_EPIS_P	TOTAL	2,452,567	1,222,630	312,115	164,246	714,009	34,846	595	3,295	830
454x-Rent from Electric Prop - Transmission	512,990	TRANS_TOTAL	TOTAL	512,990	249,345	64,038	35,138	156,153	7,443	125	599	149
454x-Rent from Electric Prop - Other Dist	1,041,438	RB_GUP_EPIS_D	TOTAL	1,041,438	745,926	182,038	43,182	20,028	9,821	186	34,168	5,336
456-Other Electric Revenue - Production Energy	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
456-Other Electric Revenue - Transmission	96,345,435	TRANS_TOTAL	TOTAL	96,345,435	46,829,917	12,027,055	6,599,363	29,327,286	1,397,894	23,410	112,547	27,963
456-Other Electric Revenue - Dist	391,475	RB_GUP_EPIS_D	TOTAL	391,475	280,393	68,710	16,232	7,529	3,692	70	12,844	2,006
456-Other Electric LSE Charge	(58,560,679)	TRAN_LSE	TOTAL	(58,560,679)	(28,714,814)	(7,350,748)	(3,987,751)	(17,550,788)	(844,846)	(14,383)	(77,985)	(19,365)
456-Other Electric Revenues DSM	573,593	PROD_DEMAND	TOTAL	573,593	281,257	71,999	39,059	171,907	8,275	141	764	190
Total Other Operating Revenues	49,032,636		TOTAL	49,032,636	24,910,425	6,848,524	3,290,803	13,200,484	654,335	10,885	97,792	19,388
Other Operating Revenue Adjustments												
Adj 6 - Misc Charges Revenue	643,148	MISC_SERV_REV	TOTAL	643,148	569,971	59,078	1,022	131	-	-	12,945	-
Adj 11 - DSM	(573,590)	PROD_DEMAND	TOTAL	(573,590)	(281,256)	(71,999)	(39,059)	(171,906)	(8,275)	(141)	(764)	(190)
Adj 16 - PJM LSE OATT Expense	(4,256,853)	TRAN_LSE	TOTAL	(4,256,853)	(2,087,318)	(534,336)	(289,875)	(1,275,790)	(61,413)	(1,045)	(5,669)	(1,408)
Adj 18 - Wholesale Load - Transmission	1,475,001	TRANS_TOTAL	TOTAL	1,475,001	716,943	184,128	101,033	448,986	21,401	358	1,723	428
Adj 18 - Wholesale Load - Production	37,348	PROD_DEMAND	TOTAL	37,348	18,134	4,688	2,543	11,193	539	9	50	12
Adj 18 - Wholesale Load - Distribution	6,582	DIST_OHNLINES	TOTAL	6,582	5,029	1,205	204	88	48	1	6	3
Adj 17 - Rent from Electric Prop - Pole Attch	(271,394)	DIST_OHNLINES	TOTAL	(271,394)	(207,332)	(49,671)	(8,407)	(3,609)	(1,964)	(39)	(253)	(120)
Total Other Operating Revenue Adjustments	(2,939,757)		TOTAL	(2,939,757)	(1,265,649)	(406,906)	(232,539)	(990,907)	(49,664)	(857)	8,039	(1,274)
Total Other Operating Revenues	46,092,878		TOTAL	46,092,878	23,644,776	6,441,618	3,058,265	12,209,577	604,670	10,028	105,831	18,114
Total Operating Revenues	665,465,504		TOTAL	665,465,504	302,002,829	104,705,604	54,312,711	180,868,639	12,553,658	239,686	8,948,875	1,833,502
Operating Expense												
O&M Expense												



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Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
Production												
500-Supervision & Engineering	4,014,121	LABOR_PROD	TOTAL	4,014,121	1,754,991	492,411	283,516	1,405,208	60,160	1,168	13,341	3,326
501-Fuel Delivered and Consumed	129,122,177	PROD_ENERGY	TOTAL	129,122,177	46,940,105	15,328,520	9,573,408	54,217,193	2,035,429	45,662	785,718	196,141
502-Steam / Consumables	5,054,588	PROD_ENERGY	TOTAL	5,054,588	1,837,507	600,047	374,759	2,122,374	79,678	1,787	30,758	7,678
503-Steam other Sources	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
504-Steam Transferred Credit	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
505-Electric	57,265	PROD_DEMAND	TOTAL	57,265	28,079	7,188	3,900	17,162	826	14	76	19
506-Misc. Steam Power Expenses	5,986,481	PROD_DEMAND	TOTAL	5,986,481	2,935,429	751,445	407,656	1,794,164	86,366	1,470	7,972	1,980
507-Rents	951	PROD_DEMAND	TOTAL	951	466	119	65	285	14	0	1	0
508-IPP Operations	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
509-Allowances	78,692	PROD_ENERGY	TOTAL	78,692	28,607	9,342	5,834	33,042	1,240	28	479	120
510-Supervision & Engineering	1,332,580	LABOR_PROD	TOTAL	1,332,580	582,610	163,467	94,120	466,491	19,971	388	4,429	1,104
511-Structures	1,959,537	PROD_DEMAND	TOTAL	1,959,537	960,845	245,968	133,437	587,278	28,270	481	2,610	648
512-Boiler Plant	14,653,787	PROD_ENERGY	TOTAL	14,653,787	5,327,128	1,739,599	1,086,465	6,152,988	230,996	5,182	89,169	22,260
513-Electric Plant	4,315,214	PROD_DEMAND	TOTAL	4,315,214	2,115,935	541,661	293,849	1,293,281	62,255	1,060	5,747	1,427
514-Misc Steam Plant	1,385,832	PROD_DEMAND	TOTAL	1,385,832	679,533	175,955	94,370	415,337	19,983	340	1,846	458
555-Purchased Power Expense Demand	6,928,075	PROD_DEMAND	TOTAL	6,928,075	3,397,133	869,637	471,775	2,076,362	99,950	1,702	9,226	2,291
555-Purchased Power Expense Energy	123,694,379	PROD_ENERGY	TOTAL	123,694,379	44,966,924	14,684,168	9,170,979	51,938,112	1,949,868	43,743	752,689	187,896
556-Sys Control & Load Dispatching	62,312	PROD_DEMAND	TOTAL	62,312	30,554	7,822	4,243	18,675	899	15	83	21
557- Other Expenses	784,560	PROD_DEMAND	TOTAL	784,560	384,703	98,481	53,425	235,135	11,319	193	1,045	259
Total Production Expenses	299,430,551		TOTAL	299,430,551	111,970,549	35,713,830	22,051,799	122,773,089	4,687,235	103,233	1,705,187	425,628
Transmission												
560-Supervision & Engineering	1,987,292	EXP_OM_TRAN	TOTAL	1,987,292	965,948	248,079	136,123	604,926	28,834	483	2,321	577
561-Load Dispatching - Company	575,380	TRANS_TOTAL	TOTAL	575,380	279,671	71,826	39,412	175,144	8,348	140	672	167
561-Load Dispatching - PJM	1,801,807	TRAN_LSE	TOTAL	1,801,807	883,503	226,169	122,896	540,006	25,994	443	2,399	596
562-Station Equipment	240,827	TRANS_TOTAL	TOTAL	240,827	117,057	30,063	16,496	73,307	3,494	59	281	70
563-Overhead Lines	21,540	TRANS_TOTAL	TOTAL	21,540	10,470	2,689	1,475	6,557	313	5	25	6
564-Underground Lines	16	TRANS_TOTAL	TOTAL	16	8	2	1	5	0	0	0	0
565 LSE Transmission Purchases	83,552,775	TRAN_LSE	TOTAL	83,552,775	40,969,511	10,487,846	5,689,614	25,040,985	1,205,403	20,521	111,267	27,630
565 LSE Transmission Purchases - Retail Energy	167,304	PROD_ENERGY	TOTAL	167,304	80,820	19,861	12,404	70,249	2,637	59	1,018	254
565 Transmission by Others	97,101	TRANS_TOTAL	TOTAL	97,101	47,197	12,121	6,651	29,557	1,409	24	113	28
565 Transmission Purchases - Non-Juris	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
566-Misc Transmission	1,152,078	TRANS_TOTAL	TOTAL	1,152,078	559,982	143,817	78,914	350,689	16,716	280	1,346	334
567-Rents	246	TRANS_TOTAL	TOTAL	246	120	31	17	75	4	0	0	0
Total Transmission Expenses	89,596,366		TOTAL	89,596,366	43,894,288	11,242,504	6,103,803	26,891,501	1,293,152	22,012	119,444	29,662
Transmission O&M												
568-Supervision & Engineering	14,796	EXP_OM_TRAN	TOTAL	14,796	7,192	1,847	1,013	4,504	215	4	17	4
569-Structures	220,169	TRANS_TOTAL	TOTAL	220,169	107,016	27,484	15,081	67,019	3,194	53	257	64
570-Station Equipment	505,968	TRANS_TOTAL	TOTAL	505,968	245,932	63,161	34,657	154,015	7,341	123	591	147
571-Overhead Lines	5,789,286	TRANS_TOTAL	TOTAL	5,789,286	2,813,956	722,692	396,548	1,762,243	83,998	1,407	6,763	1,680
572-Underground Lines	115	TRANS_TOTAL	TOTAL	115	56	14	8	35	2	0	0	0
573-Misc Transmission Expenses	9,102	TRANS_TOTAL	TOTAL	9,102	4,424	1,136	623	2,771	132	2	11	3
575- PJM Admin	1,378,079	TRAN_LSE	TOTAL	1,378,079	675,731	172,981	93,842	413,014	19,881	338	1,835	456
Total Transmission Maintenance	7,917,515		TOTAL	7,917,515	3,854,307	989,317	541,773	2,403,600	114,763	1,927	9,474	2,354
Total Transmission O&M	97,513,881		TOTAL	97,513,881	47,748,594	12,231,821	6,645,576	29,295,101	1,407,915	23,940	128,918	32,016
Distribution Operation												
580 Supervision & Engineering	1,450,289	TOTOXEXP	TOTAL	1,450,289	1,018,834	272,916	62,608	33,013	13,263	285	39,122	10,248
581 Load Dispatching	2,861	DIST_CPD	TOTAL	2,861	1,901	484	265	148	57	1	4	1
582 Station Expenses	369,656	DIST_CPD	TOTAL	369,656	245,636	62,563	34,238	19,113	7,411	125	456	114
583 Overhead Lines	722,883	DIST_OHLINES	TOTAL	722,883	552,247	132,302	22,393	9,612	5,230	104	674	320
584 Underground Lines	362,478	DIST_UGLINES	TOTAL	362,478	272,118	64,405	15,896	4,975	3,922	70	835	256
585 Street Lighting	32,865	DIST_SL	TOTAL	32,865	-	-	-	-	-	-	-	32,865
586 Meters	1,214,835	DIST_METERS	TOTAL	1,214,835	746,311	342,753	62,268	55,612	7,512	379	-	-
587 Customer Installs	158,939	DIST_PCUST	TOTAL	158,939	99,630	23,617	324	30	98	6	35,194	41
588 Miscellaneous Distribution	5,771,633	RB_GUP_EPIS_D	TOTAL	5,771,633	4,133,911	1,013,014	239,316	110,996	54,430	1,033	189,360	29,574
589 Rents	1,104,179	RB_GUP_EPIS_D	TOTAL	1,104,179	790,864	193,801	45,784	21,235	10,413	198	36,227	5,658
Total Distribution Operations Expenses	11,190,618		TOTAL	11,190,618	7,861,452	2,105,857	483,093	254,733	102,335	2,201	301,871	79,076
Distribution Maintenance												
590 Supervision & Engineering	57,034	TOTMXPXP	TOTAL	57,034	43,330	10,409	1,878	829	435	9	105	39
591 Structures	14,891	DIST_CPD	TOTAL	14,891	9,895	2,520	1,379	770	299	5	18	5
592 Station Equipment	951,869	DIST_CPD	TOTAL	951,869	632,516	161,101	88,164	49,216	19,082	321	1,175	293
593 Overhead Lines	29,247,953	TOTOHLINES	TOTAL	29,247,953	22,344,007	5,352,966	906,020	388,889	211,622	4,213	27,276	12,960
5930010 Storm Expense Amortization	-	TOTOHLINES	TOTAL	-	-	-	-	-	-	-	-	-
593-Forestry Direct Assigned	400,407	TOTOHLINES	TOTAL	400,407	305,891	73,283	12,403	5,324	2,897	58	373	177
594 Underground Lines	33,611	TOTUGLINES	TOTAL	33,611	5,972	1,474	461	364	7	77	24	24
595 Line Transformers	7,703	DIST_TRANSF	TOTAL	7,703	5,780	1,361	348	99	87	2	20	6
596 Street Lighting	7,679	DIST_SL	TOTAL	7,679	-	-	-	-	-	-	-	7,679

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Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	OL 17	SL 18
597 Meters	41,511	DIST_METERS	TOTAL	41,511	25,501	11,712	2,128	1,900	257	13	-	-
598 Miscellaneous Distribution	27,519	DIST_OL	TOTAL	27,519	-	-	-	-	-	-	27,519	-
Total Distribution Maintenance Expenses	30,790,177		TOTAL	30,790,177	23,392,153	5,619,325	1,013,794	447,489	235,043	4,626	56,565	21,183
Total Distribution O&M	41,980,795		TOTAL	41,980,795	31,253,605	7,725,182	1,496,887	702,222	337,378	6,827	358,436	100,259
Customer Accounts												
901 Supervision	19,726	TOTOX234	TOTAL	19,726	16,506	3,197	48	7	14	1	(51)	5
902 Meter Read	377,828	CUST_902	TOTAL	377,828	276,493	98,361	2,105	376	477	17	-	-
903 Customer Records	4,647,019	CUST_903	TOTAL	4,647,019	3,916,036	715,208	10,030	1,367	2,965	185	-	1,228
904 Uncollectibles	(57,939)	CUST_TOTAL	TOTAL	(57,939)	(36,313)	(8,609)	(121)	(16)	(36)	(2)	(12,827)	(15)
905 Miscellaneous	23,591	TOTOX234	TOTAL	23,591	19,741	3,823	57	8	16	1	(61)	6
Total	5,010,225		TOTAL	5,010,225	4,192,462	811,981	12,119	1,741	3,436	201	(12,939)	1,224
907 - 910 Total Customer Services Expenses	1,776,402	CUST_TOTAL	TOTAL	1,776,402	1,113,351	263,942	3,701	504	1,094	68	393,289	453
911 - 916 Total Sales Expenses	9,329	CUST_TOTAL	TOTAL	9,329	5,847	1,386	19	3	6	0	2,065	2
Administrative & General Expense												
920-Salaries	11,916,144	LABOR_M	TOTAL	11,916,144	7,130,730	1,801,455	603,498	2,156,186	130,504	2,549	74,810	16,412
921-Office Supplies	839,285	LABOR_M	TOTAL	839,285	502,236	126,881	42,506	151,866	9,192	180	5,269	1,156
922-Administrative Expense Transferred	(1,697,003)	LABOR_M	TOTAL	(1,697,003)	(1,015,502)	(255,549)	(85,945)	(307,067)	(18,585)	(363)	(10,654)	(2,337)
923-Outside Services	5,859,741	LABOR_M	TOTAL	5,859,741	3,506,523	885,862	296,769	1,060,301	64,175	1,253	36,788	8,070
924-Property Insurance	1,096,504	RB_GUP_EPIS	TOTAL	1,096,504	646,341	161,866	61,492	194,795	13,336	236	15,867	2,571
925-Injuries & Damages	1,866,779	LABOR_M	TOTAL	1,866,779	1,117,098	282,215	94,544	337,787	20,445	399	11,720	2,571
926-Employee Pension & Benefits	982,462	LABOR_M	TOTAL	982,462	587,914	148,526	49,757	177,773	10,760	210	6,168	1,353
9260057 Post Ret Medicare Subsidy Direct	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
927-Franchise Requirements	160,295	LABOR_M	TOTAL	160,295	95,922	24,233	8,118	29,005	1,756	34	1,006	221
928-Regulatory Commission Expense Allocated	979,706	LABOR_M	TOTAL	979,706	586,265	148,110	49,818	177,275	10,730	210	6,151	1,349
928- Rate Case Expense	2,290,044	RSale	TOTAL	2,290,044	1,035,260	367,172	190,511	611,390	44,755	844	33,332	6,780
930-General Advertising Expense	687,804	LABOR_M	TOTAL	687,804	411,588	103,981	34,834	124,456	7,533	147	4,318	947
931-Rent	68,537	LABOR_M	TOTAL	68,537	41,013	10,361	3,471	12,402	751	15	430	94
Total A&G Operation	25,050,297		TOTAL	25,050,297	14,645,387	3,804,112	1,349,174	4,726,168	295,349	5,714	185,206	39,187
Total A&G Maintenance	2,233,529	LABOR_M	TOTAL	2,233,529	1,336,564	337,660	113,118	404,150	24,461	478	14,022	3,076
Total A&G Expenses	27,283,826		TOTAL	27,283,826	15,981,951	4,141,772	1,462,292	5,130,318	319,810	6,192	199,228	42,264
Total O&M Expenses	473,005,010		TOTAL	473,005,010	212,266,359	60,889,914	31,672,394	157,902,977	6,756,874	140,462	2,774,184	601,846
O&M Adjustments												
Adj 19 - Env Surcharge - Remove Mitchell FGD Expenses	(3,541,349)	PROD_ENERGY	TOTAL	(3,541,349)	(1,287,395)	(420,405)	(262,564)	(1,486,979)	(55,824)	(1,252)	(21,549)	(5,379)
Adj 9 - Fuel Under (Over) Revenue & Expense	(42,632,032)	PROD_ENERGY	TOTAL	(42,632,032)	(15,498,128)	(5,060,989)	(3,160,835)	(17,900,791)	(672,034)	(15,076)	(258,419)	(64,759)
Adj 10 - Remove PPA Rider Revenue, Expense	(3,562,775)	PROD_ENERGY	TOTAL	(3,562,775)	(1,295,184)	(422,949)	(264,152)	(1,495,976)	(56,162)	(1,280)	(21,680)	(5,412)
Adj - Remove BSDR Rider Exp	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 11 & 12 - Remove HEAP & DSM Surcharge	(1,143,842)	CUST_TOTAL	TOTAL	(1,143,842)	(716,897)	(169,955)	(2,383)	(325)	(704)	(44)	(253,242)	(292)
Adj 13 - Remove Economic Development Surcharge	(373,894)	CUST_TOTAL	TOTAL	(373,894)	(234,336)	(55,554)	(779)	(106)	(230)	(14)	(82,779)	(95)
Adj 18 - Wholesale Load	4,901,693	RB_GUP	TOTAL	4,901,693	2,889,333	723,587	274,889	870,792	59,615	1,054	70,932	11,491
Adj 14 - Customer Annualization Adjustment	(1,596,918)	REVYEC_FXNL	TOTAL	(1,596,918)	(618,278)	(185,838)	(112,071)	(606,580)	(52,864)	-	(21,287)	-
Adj 15 - Weather Normalization Adjustment	(428,369)	WEATHER_FXNL	TOTAL	(428,369)	(145,320)	(181,901)	(84,895)	-	(16,342)	-	-	-
Adj 21 - Normalization of Major Storms	215,408	TDOMX	TOTAL	215,408	150,877	37,466	8,887	14,166	1,969	38	1,569	437
Adj 22 - Amortization of Storm Expense Reg Assets	-	TDOMX	TOTAL	-	-	-	-	-	-	-	-	-
Adj 23 - Rate Case Expense	241,939	RSale	TOTAL	241,939	109,373	38,791	20,127	64,592	4,728	89	3,521	716
Adj 24 - Eliminate Misc Expense	(54,804)	LABOR_M	TOTAL	(54,804)	(32,795)	(8,285)	(2,776)	(9,917)	(600)	(12)	(344)	(75)
Adj 25 - Annualization of Lease Costs	116,943	RB_GUP	TOTAL	116,943	68,933	17,263	6,558	20,775	1,422	25	1,692	274
Adj 26 - Pension & OPEB Expense Adjustment	4,985,007	LABOR_M	TOTAL	4,985,007	2,983,074	753,622	252,468	902,020	54,595	1,066	31,296	6,866
Adj 27 - Employee Related Group Benefit Expenses	(61,787)	LABOR_M	TOTAL	(61,787)	(36,974)	(9,341)	(3,129)	(11,180)	(677)	(13)	(388)	(85)
Adj 16 - PJM LSE OATT Expense	5,725,020	TRAN_LSE	TOTAL	5,725,020	2,807,223	718,625	389,851	1,715,803	82,594	1,406	7,624	1,893
Adj - Normalize bad debt expense	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Adj 29 - Severance Related Payroll Expense	(3,086,549)	LABOR_M	TOTAL	(3,086,549)	(1,847,019)	(466,617)	(156,320)	(558,501)	(33,803)	(660)	(19,378)	(4,251)
Adj 30 - Total Incentive Compensation & Payroll Adj	3,130,903	LABOR_M	TOTAL	3,130,903	1,873,561	473,323	158,566	566,526	34,289	670	19,656	4,312
Adj 36 - Remove Non-Recoverable Business Expenses	(24,171)	RB_GUP	TOTAL	(24,171)	(14,248)	(3,568)	(1,356)	(4,294)	(294)	(5)	(350)	(57)
Adj 50 - Veg Management Tree Trimming 1	621,974	TOTOHLINES	TOTAL	621,974	475,158	113,834	19,267	8,270	4,500	90	580	276
Adj 50 - Veg Management Tree Trimming 2	(6,781,936)	TDOMX	TOTAL	(6,781,936)	(4,750,235)	(1,179,571)	(279,785)	(446,007)	(61,986)	(1,196)	(49,385)	(13,771)
Adj 40 - KPSC Maintenance Assessment	114,529	CUST_TOTAL	TOTAL	114,529	71,780	17,017	239	33	71	4	25,356	29
Adj 46 - Remove Pension Settlement Costs from Rate Base	(1,689,276)	LABOR_M	TOTAL	(1,689,276)	(1,010,878)	(255,381)	(85,554)	(305,669)	(18,501)	(361)	(10,605)	(2,327)
Adj 47 - Request to Defer and Amortize Direct Pension Settlement	140,773	LABOR_M	TOTAL	140,773	84,240	21,282	7,130	25,472	1,542	30	884	194
Adj - Def and Amortize GreenHat Default Charges	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Adj 17 - Removal of Pole Rental Rev & Exp to prior periods	21,148	RB_GUP_EPIS_D	TOTAL	21,148	15,147	3,712	877	407	199	4	694	108
Adj - Removal Non-Ongoing Exp - COVID-19 Pandemic	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Adj - Removal Prior Period Insurance Proceeds	-	CUST_903	TOTAL	-	-	-	-	-	-	-	-	-

**KENTUCKY POWER COMPANY**  
**COST-OF-SERVICE STUDY**  
**TWELVE MONTHS ENDING**  
**MAY 31, 2025**

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<u>Label</u>	<u>Constant</u>	<u>Allocation Factor</u>	<u>Function</u>	<u>Total Retail</u> <u>1</u>	<u>RS</u> <u>2</u>	<u>Total GS</u>	<u>Total LGS</u>	<u>Total IGS</u>	<u>Total PS</u>	<u>MW</u> <u>16</u>	<u>OL</u> <u>17</u>	<u>SL</u> <u>18</u>
Adj - Removal Rockport - Energy		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Adj - Amortization Deferred Plant Maintenance Costs		PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Adj 40 - Non-FAC Eligible Cost Adj5	1,212,198	PROD_ENERGY	TOTAL	1,212,198	440,673	143,904	89,875	508,990	19,109	429	7,376	1,841
Adj - Removal of Regulatory Asset Amortization		RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Total Operations and Maintenance Expense Adjustments	(43,550,167)		TOTAL	(43,550,167)	(15,518,226)	(5,357,930)	(3,187,865)	(18,128,477)	(705,389)	(14,989)	(569,224)	(68,066)
<b>Adjusted Operating &amp; Maintenance Expenses</b>	<b>429,454,843</b>		<b>TOTAL</b>	<b>429,454,843</b>	<b>196,748,133</b>	<b>55,531,984</b>	<b>28,484,530</b>	<b>139,774,500</b>	<b>6,051,485</b>	<b>125,472</b>	<b>2,204,959</b>	<b>533,780</b>
<b>Depreciation, Amortization &amp; Reg. Debits Expense</b>												
Production & Reg Debits	44,250,697	RB_GUP-Land_P	TOTAL	44,250,697	22,060,640	5,631,627	2,963,251	12,881,322	628,684	10,731	59,457	14,984
Transmission & Reg. Debits	24,741,459	RB_GUP-Land_T	TOTAL	24,741,459	12,022,653	3,088,018	1,695,017	7,534,792	359,041	6,010	28,778	7,150
Distribution	41,277,493	RB_GUP-Land_D	TOTAL	41,277,493	29,586,094	7,247,435	1,690,538	780,491	384,911	7,325	1,367,219	213,480
General & Intangible	14,332,733	RB_GUP-Land_G	TOTAL	14,332,733	8,576,839	2,166,789	725,888	2,593,460	156,970	3,066	89,982	19,740
Total Depreciation & Amort Expense	124,602,382		TOTAL	124,602,382	72,246,226	18,133,869	7,074,694	23,790,064	1,529,606	27,132	1,545,436	255,355
Depreciation & Amortization Adjustments												
Adj 7 - Decommissioning Rider Removal	(209,318)	RB_GUP-Land_P	TOTAL	(209,318)	(104,353)	(26,639)	(14,017)	(60,932)	(2,974)	(51)	(281)	(71)
Adj 49 - Remove Mitchell from Rate Base and Cost of Service	(8,425,896)	RB_GUP-Land_P	TOTAL	(8,425,896)	(4,200,627)	(1,072,333)	(564,241)	(2,452,768)	(119,709)	(2,043)	(11,321)	(2,853)
Adj 19 - Env Surcharge - Remove Mitchell FGD Expenses	(9,355,669)	RB_GUP-Land_P	TOTAL	(9,355,669)	(4,664,154)	(1,190,662)	(626,503)	(2,723,423)	(132,919)	(2,269)	(12,571)	(3,168)
Adj 8 - Environmental Surcharge Revenue Sync	1,980,517	RB_GUP-Land_P	TOTAL	1,980,517	987,362	252,053	132,625	576,526	28,138	480	2,661	671
Adj 28 - NERC Compliance & Cyber Security	465,475	RB_GUP-Land_P	TOTAL	465,475	232,057	59,239	31,171	135,499	6,613	113	625	158
Adj 18 - Wholesale Load Production	549,777	RB_GUP-Land_P	TOTAL	549,777	274,084	69,968	36,816	160,039	7,811	133	739	186
Adj 18 - Wholesale Load Transmission	500,818	RB_GUP-Land_T	TOTAL	500,818	243,363	62,508	34,311	152,520	7,268	122	583	145
Adj 18 - Wholesale Load Distribution	41,318	RB_GUP-Land_D	TOTAL	41,318	29,615	7,255	1,692	781	385	7	1,369	214
Adj 18 - Wholesale Load General	292,505	RB_GUP-Land_G	TOTAL	292,505	175,038	44,220	14,814	52,928	3,203	63	1,836	403
Adj 37 & 48 - Annualization Depreciation/Amortization Exp Produc	2,255,639	RB_GUP-Land_P	TOTAL	2,255,639	1,124,521	287,067	151,049	656,614	32,047	547	3,031	764
Adj 37 & 48 - Annualization Depreciation/Amortization Exp Transr	(1,592,344)	RB_GUP-Land_T	TOTAL	(1,592,344)	(773,770)	(196,743)	(109,090)	(484,934)	(23,108)	(387)	(1,852)	(460)
Adj 37 & 48 - Annualization Depreciation/Amortization Exp Distrib	4,536,287	RB_GUP-Land_D	TOTAL	4,536,287	3,251,433	796,474	185,786	85,774	42,301	805	150,254	23,461
Adj 37 & 48 - Annualization Depreciation/Amortization Exp Gener	(89,190)	RB_GUP-Land_G	TOTAL	(89,190)	(53,372)	(13,483)	(4,517)	(16,139)	(977)	(19)	(560)	(123)
Adj 50 - Veg Management Tree Trimming & Dist Investments	585,000	RB_GUP-Land_D	TOTAL	585,000	419,305	102,713	23,959	11,061	5,455	104	19,377	3,026
Adj 38 - ARO Depreciation Expense	113,369	RB_GUP-Land_P	TOTAL	113,369	56,515	14,428	7,592	33,002	1,611	27	152	38
Total Depreciation & Amort Adjustments	(8,351,713)		TOTAL	(8,351,713)	(3,002,978)	(805,936)	(698,554)	(3,873,452)	(144,855)	(2,367)	154,041	22,389
<b>Adjusted Depreciation &amp; Amortization Expense</b>	<b>116,250,669</b>		<b>TOTAL</b>	<b>116,250,669</b>	<b>69,243,248</b>	<b>17,327,933</b>	<b>6,376,140</b>	<b>19,916,611</b>	<b>1,384,751</b>	<b>24,765</b>	<b>1,699,477</b>	<b>277,744</b>
<b>Taxes Other Than Income</b>												
Federal Insurance Contribution Excise	2,156,050	LABOR_M	TOTAL	2,156,050	1,290,200	325,947	109,194	390,130	23,613	461	13,536	2,989
Federal Unemployment Tax	9,753	LABOR_M	TOTAL	9,753	5,836	1,474	494	1,765	107	2	61	13
Kentucky Unemployment	16,661	LABOR_M	TOTAL	16,661	9,970	2,519	844	3,015	182	4	105	23
Kentucky Real & Personal Property	13,290,680	RB_GUP	TOTAL	13,290,680	7,834,272	1,961,968	745,348	2,361,106	161,642	2,858	192,328	31,157
Kentucky PSC Maintenance	-	RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Kentucky Sales & Use	54,734	TDPLANT	TOTAL	54,734	33,696	8,394	2,916	7,875	638	11	1,039	165
Regis Fee	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Kentucky Business Occup Taxes	5,393,247	LABOR_M	TOTAL	5,393,247	3,227,368	815,338	273,143	975,890	59,066	1,154	33,859	7,428
Gross Receipts	19,397	RSALE	TOTAL	19,397	8,769	3,110	1,614	5,179	379	7	282	57
Business Franchise Taxes	-	RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Federal Excise	14,582	LABOR_M	TOTAL	14,582	8,726	2,204	739	2,639	160	3	92	20
Taxes on Capital Leases	103,946	RB_GUP	TOTAL	103,946	61,272	15,344	5,829	18,466	1,264	22	1,504	244
Total Taxes Other Than Income	21,059,050		TOTAL	21,059,050	12,480,110	3,136,299	1,140,121	3,766,063	247,051	4,523	242,806	42,077
Taxes Other Than Income Adjustments												
Adj 19 - Env Surcharge - Remove Mitchell FGD Expenses	(188,833)	RB_GUP	TOTAL	(188,833)	(111,309)	(27,875)	(10,590)	(33,546)	(2,297)	(41)	(2,733)	(443)
Adj 18 Wholesale Load - Payroll	19,821	LABOR_M	TOTAL	19,821	11,861	2,996	1,004	3,586	217	4	124	27
Adj 30 - Total Incentive Compensation & Payroll Adj5	247,150	LABOR_M	TOTAL	247,150	147,897	37,364	12,517	44,721	2,707	53	1,552	340
Adj 18 - Wholesale Load	356,739	RB_GUP	TOTAL	356,739	210,282	52,662	20,006	63,375	4,339	77	5,162	836
Adj 42 - Property Tax Expense Annualization	4,262,813	RB_GUP	TOTAL	4,262,813	2,512,741	629,276	239,061	757,294	51,845	917	61,687	9,993
Adj - Sales and Use Tax	-	TDPLANT	TOTAL	-	-	-	-	-	-	-	-	-
Adj 44 - State Business and Occupation Taxes	1,190,525	LABOR_M	TOTAL	1,190,525	712,421	179,981	60,295	215,422	13,038	255	7,474	1,640
Total Adjustments to Taxes Other Than Income	5,888,216		TOTAL	5,888,216	3,483,894	874,403	322,292	1,050,852	69,849	1,265	73,267	12,394
<b>Adjusted Taxes Other Than Income</b>	<b>26,947,266</b>		<b>TOTAL</b>	<b>26,947,266</b>	<b>15,964,004</b>	<b>4,010,702</b>	<b>1,462,413</b>	<b>4,816,915</b>	<b>316,900</b>	<b>5,787</b>	<b>316,072</b>	<b>54,472</b>
<b>Other Expenses</b>												
Gain/Loss on Disposition of Utility Plant	(15,351)	RB_GUP_EPIS_D	TOTAL	(15,351)	(10,995)	(2,694)	(637)	(295)	(145)	(3)	(504)	(79)
A/R Factoring	4,507,850	RB_GUP	TOTAL	4,507,850	2,657,179	665,448	252,802	800,825	54,825	969	65,233	10,568
Gain/Loss on Disposition of Allowances	(178,191)	PROD_ENERGY	TOTAL	(178,191)	(64,778)	(21,154)	(13,211)	(74,821)	(2,809)	(63)	(1,084)	(271)
Accretion	2,038,296	PROD_DEMAND	TOTAL	2,038,296	999,466	255,854	138,800	610,883	29,406	501	2,714	674
Interest Income - Corp. Borrowing Program	(283)	RB_GUP	TOTAL	(283)	(167)	(42)	(16)	(50)	(3)	(0)	(4)	(1)
Interest Expense - Corp. Borrowing Program	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Other Interest Expense	669,476	RB_GUP	TOTAL	669,476	394,627	98,828	37,545	118,933	8,142	144	9,688	1,569
Interest on Customer Deposits	1,839,862	CUST_DEP_FXNL	TOTAL	1,839,862	1,221,417	282,407	146,978	181,149	1,387	-	6,524	-

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Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	QL 17	SL 18
Total Other Expenses	8,861,659		TOTAL	8,861,659	5,196,747	1,278,647	562,261	1,636,624	90,803	1,548	82,567	12,461
Other Expense Adjustments												
Adj 20 - Interest on Customer Deposits	(243,879)	CUST_DEP_FXNL	TOTAL	(243,879)	(161,902)	(37,434)	(19,482)	(24,012)	(184)	-	(865)	-
Adj 18 - Wholesale Load	28,502	PROD_DEMAND	TOTAL	28,502	13,976	3,578	1,941	8,542	411	7	38	9
Adj 39 - ARO Depreciation	124,567	PROD_DEMAND	TOTAL	124,567	61,080	15,636	8,482	37,333	1,797	31	166	41
Total Adjustments to Other Expenses	(90,810)		TOTAL	(90,810)	(86,846)	(18,220)	(9,059)	21,863	2,025	38	(661)	51
Total Adjusted Other Expenses	8,770,849		TOTAL	8,770,849	5,109,901	1,260,427	553,202	1,658,487	92,827	1,586	81,906	12,512
Total Operating Expense Before Income Tax	581,423,627		TOTAL	581,423,627	287,065,286	78,131,046	36,876,285	166,166,514	7,845,964	157,610	4,302,414	878,507
Gross Operating Income	84,041,878		TOTAL	84,041,878	14,937,543	26,574,558	17,436,426	14,702,124	4,707,694	82,076	4,646,461	954,995
Allowance for Borrowed Funds Used During Construction	9,843,020	RATEBASE	TOTAL	9,843,020	5,663,454	1,433,756	560,957	1,891,602	124,617	2,228	143,038	23,369
Interest Synchronization Tax & Wholesale PTBI Change	(58,415,664)	RATEBASE	TOTAL	(58,415,664)	(33,611,066)	(8,508,954)	(3,329,130)	(11,226,149)	(739,565)	(13,221)	(848,890)	(138,687)
Taxable Income Before Schedule M Adjustments	35,469,234		TOTAL	35,469,234	(13,010,070)	19,499,360	14,668,253	5,367,578	4,092,746	71,083	3,940,608	839,676
Schedule M Income Adjustments												
Book vs. Tax Depreciation - Normalized	(306,565)	RB_GUP	TOTAL	(306,565)	(180,707)	(45,255)	(17,192)	(54,462)	(3,728)	(66)	(4,436)	(719)
AFUDC - HR/J	-	BULK_TRANS	TOTAL	-	-	-	-	-	-	-	-	-
ABFUDC	-	RB_GUP_CWIP	TOTAL	-	-	-	-	-	-	-	-	-
ABFUDC - HR/J	38,037	BULK_TRANS	TOTAL	38,037	18,651	4,775	2,590	11,400	549	9	51	13
Interest Capitalization	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Capitalized Relocation Costs	(1,697,849)	RB_GUP	TOTAL	(1,697,849)	(1,000,807)	(250,636)	(95,216)	(301,625)	(20,649)	(365)	(24,569)	(3,980)
Book/Tax Unit of Property	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Percent Repair Allowance	(37,370,098)	RB_GUP	TOTAL	(37,370,098)	(22,028,032)	(5,516,567)	(2,095,734)	(6,638,844)	(454,499)	(8,036)	(540,779)	(87,607)
Removal Costs	(13,321,140)	RB_GUP	TOTAL	(13,321,140)	(7,852,227)	(1,966,464)	(747,056)	(2,366,517)	(162,013)	(2,865)	(192,769)	(31,229)
Tax Amortization of Pollution Control	7,544,471	PROD_DEMAND	TOTAL	7,544,471	3,699,378	947,009	513,749	2,261,098	108,843	1,853	10,047	2,495
Property Tax - State 2- Old Method	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Provision for Possible Revenue Refunds	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Deferred Fuel	4,798,018	FUELREV	TOTAL	4,798,018	1,744,235	569,589	355,736	2,014,643	75,634	1,697	29,196	7,288
Insurance premiums accrued	(18,865)	LABOR_M	TOTAL	(18,865)	(11,289)	(2,852)	(955)	(3,414)	(207)	(4)	(118)	(26)
Accrued Book Pension Expense	(92,555)	LABOR_M	TOTAL	(92,555)	(55,386)	(13,992)	(4,687)	(16,748)	(1,014)	(20)	(581)	(127)
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	(35,176)	LABOR_M	TOTAL	(35,176)	(21,050)	(5,318)	(1,782)	(6,365)	(385)	(8)	(221)	(48)
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	(640,064)	TDPLANT	TOTAL	(640,064)	(394,047)	(98,161)	(34,103)	(92,090)	(7,457)	(132)	(12,146)	(1,927)
Deferred Book Contract Revenue	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Deferred Storm Damage	-	EXP_OM_DIST	TOTAL	-	-	-	-	-	-	-	-	-
OSS Margin Sharing	3,805,066	RB_GUP	TOTAL	3,805,066	2,242,919	561,703	213,390	675,975	46,278	818	55,063	8,920
Advance Rental Income	(15,160)	REV_RENT	TOTAL	(15,160)	(10,142)	(2,477)	(672)	(1,631)	(149)	(3)	(73)	(14)
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	-	-	-	-	-	-	-	-	-
Misc Fees	296	RB_GUP	TOTAL	296	174	44	17	53	4	0	4	1
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	-	-	-	-	-	-	-	-	-
REG ASSET-GreenHat Settlement & Liability	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Book Amortization Loss on Reacquired Debt	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-

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Label	Constant	Allocation Factor	Function	Total Retail 1	RS 2	Total GS	Total LGS	Total IGS	Total PS	MW 16	QL 17	SL 18
Accrued SFAS 106 Post Retirement Exp	(2,087,677)	LABOR_M	TOTAL	(2,087,677)	(1,249,285)	(315,610)	(105,731)	(377,758)	(22,864)	(447)	(13,107)	(2,875)
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		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Gross Receipts - Tax Expense		RSALE	TOTAL	-	-	-	-	-	-	-	-	-
Accured Sales & Use Tax Reserve		TDPLANT	TOTAL	-	-	-	-	-	-	-	-	-
SFAS 109 - Deferred SIT Liability		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset - SFAS 109 - Deferred SIT Liability		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Regulatory Asset Accrued SFAS 112		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Restricted Stock Plan	472	RB_GUP	TOTAL	472	278	70	26	84	6	0	7	1
Stock Based Compensation	71,673	RB_GUP	TOTAL	71,673	42,248	10,580	4,019	12,733	872	15	1,037	168
Non taxable Defd Compensation CSV Earn		LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Non deductible Meals and Travel & Entertainment	112,634	LABOR_M	TOTAL	112,634	67,401	17,028	5,704	20,381	1,234	24	707	155
RESTRICTED STOCK PLAN - TAX DEDUCTION	(18,569)	RB_GUP	TOTAL	(18,569)	(10,946)	(2,741)	(1,041)	(3,299)	(226)	(4)	(269)	(44)
Capitalized Software Costs Tax	(2,482)	RB_GUP	TOTAL	(2,482)	(1,463)	(366)	(139)	(441)	(30)	(1)	(36)	(6)
Capitalized Software Costs Book		RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET - UNRECOVERED PLANT - BIG SANDY		PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
MTM Book Gain Above the Line Tax Deferral	(4,583,583)	PROD_ENERGY	TOTAL	(4,583,583)	(1,666,281)	(544,132)	(339,837)	(1,924,604)	(72,254)	(1,621)	(27,891)	(6,963)
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	36,435	PROD_ENERGY	TOTAL	36,435	13,245	4,325	2,701	15,299	574	13	222	55
Total Schedule M Adjustments - Per Books	(43,782,681)		TOTAL	(43,782,681)	(26,653,131)	(6,649,450)	(2,346,213)	(6,776,132)	(511,483)	(9,140)	(720,662)	(116,469)
Adjustments to Per Books Schedule M												
Adj 7 - Decommissioning Rider Removal	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 8 - Environmental Surcharge Revenue Sync	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-
Adj 26 - Pension & OPEB Expense Adjustment	4,985,007	LABOR_M	TOTAL	4,985,007	2,983,074	753,622	252,468	902,020	54,595	1,066	31,296	6,866
Adj 28 - NERC Compliance & Cyber Security	-	RB_GUP-Land_P	TOTAL	-	-	-	-	-	-	-	-	-
Adj 30-35 Incentive Compensation & Payroll Adjustments	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Adj 38 - ARO Depreciation Expense	113,369	RB_GUP-Land_P	TOTAL	113,369	56,519	14,428	7,592	33,002	1,611	27	152	38
Adj 39 - ARO Accretion	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
Adj 41 - KPCCO AFUDC Offset	(5,886,173)	TRANS_TOTAL	TOTAL	(5,886,173)	(2,861,049)	(734,787)	(403,185)	(1,791,735)	(85,404)	(1,430)	(6,876)	(1,708)
Adj 18 - Wholesale Load Adjustments	(855,386)	RB_GUP	TOTAL	(855,386)	(504,212)	(126,272)	(47,970)	(151,960)	(10,403)	(184)	(12,378)	(2,005)
Adj 37 & 48 - Depreciation/Amortization Adjustments - Prod	(6,170,257)	RB_GUP-Land_P	TOTAL	(6,170,257)	(3,076,106)	(785,266)	(413,192)	(1,796,154)	(87,663)	(1,496)	(8,291)	(2,089)
Adj 37 & 48 - Depreciation/Amortization Adjustments - Trans	(1,592,344)	RB_GUP-Land_T	TOTAL	(1,592,344)	(773,770)	(1						

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<u>Label</u>	<u>Constant</u>	<u>Allocation Factor</u>	<u>Function</u>	<u>Total Retail</u> <u>1</u>	<u>RS</u> <u>2</u>	<u>Total GS</u>	<u>Total LGS</u>	<u>Total IGS</u>	<u>Total PS</u>	<u>MW</u> <u>16</u>	<u>OL</u> <u>17</u>	<u>SL</u> <u>18</u>
Tax Rate	9.50%											
Illinois Tax	-		TOTAL	-	-	-	-	-	-	-	-	-
Michigan Taxable Income Before Depreciation Adjustment	(13,272,134)		TOTAL	(13,272,134)	(40,640,684)	12,555,882	11,789,931	(4,628,680)	3,472,215	60,325	3,371,691	747,186
Depreciation Adjustments (JWCA and Lookback)	(14,232,049)	RB_GUP	TOTAL	(14,232,049)	(8,389,168)	(2,100,932)	(798,140)	(2,528,341)	(173,091)	(3,060)	(205,951)	(33,364)
Michigan Taxable Income	(27,504,183)		TOTAL	(27,504,183)	(49,029,852)	10,454,950	10,991,790	(7,157,021)	3,299,124	57,265	3,165,741	713,821
Tax Factor (Tax Rate x Apportionment)	0.000000%											
Michigan Tax	-		TOTAL	-	-	-	-	-	-	-	-	-
Total Current State Income Tax	(245,891)		TOTAL	(245,891)	(161,581)	(28,939)	(7,435)	(44,834)	(1,148)	(21)	(1,751)	(182)
Deferred State Income Tax												
Deferred State Income Tax - WVA Pollution Control	(1,152,126)	RB_GUP	TOTAL	(1,152,126)	(679,127)	(170,077)	(64,612)	(204,677)	(14,012)	(248)	(16,672)	(2,701)
Adj - Mitchell Plant DSIT Amortization Adjustment	-	RB_GUP_EPIS_P	TOTAL	-	-	-	-	-	-	-	-	-
Total Adjusted Deferred State Income Tax	(1,152,126)		TOTAL	(1,152,126)	(679,127)	(170,077)	(64,612)	(204,677)	(14,012)	(248)	(16,672)	(2,701)
Total State Income Tax (Current + Deferred)	(1,398,017)		TOTAL	(1,398,017)	(840,708)	(199,016)	(72,047)	(249,511)	(15,161)	(269)	(18,424)	(2,883)
Federal Taxable Income	(13,026,242)		TOTAL	(13,026,242)	(40,479,103)	12,584,821	11,797,366	(4,583,846)	3,473,364	60,346	3,373,443	747,368
Tax Factor (Tax Rate x Apportionment)	21.00%											
Gross Current FIT	(2,735,511)		TOTAL	(2,735,511)	(8,500,612)	2,642,813	2,477,447	(962,608)	729,406	12,673	708,423	156,947
Deferred FIT												
DFIT for Book vs Tax Depreciation Normalized	836,111	RB_GUP	TOTAL	836,111	492,851	123,427	46,890	148,536	10,169	180	12,099	1,960
ABFUDC - HR/J	(7,989)	BULK_TRANS	TOTAL	(7,989)	(3,917)	(1,003)	(544)	(2,394)	(115)	(2)	(11)	(3)
Interest Capitalization	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Property Tax - Book/Tax unit of Property Adj	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Removal Costs	4,431,928	RB_GUP	TOTAL	4,431,928	2,612,427	654,240	248,545	787,337	53,902	953	64,134	10,390
Percent Repair Allowance	7,847,720	RB_GUP	TOTAL	7,847,720	4,625,886	1,158,479	440,104	1,394,157	95,445	1,688	113,564	18,397
Tax Amortization of Pollution Control Equip.	(1,584,339)	PROD_DEMAND	TOTAL	(1,584,339)	(776,869)	(198,872)	(107,887)	(474,831)	(22,857)	(389)	(2,110)	(524)
Relocation Costs	356,549	RB_GUP	TOTAL	356,549	210,170	52,634	19,995	63,341	4,336	77	5,160	836
Deferred Fuel Costs	(1,007,584)	FUELREV	TOTAL	(1,007,584)	(366,290)	(119,614)	(74,705)	(423,075)	(15,883)	(356)	(6,131)	(1,531)
Insurance Premiums accrued	3,961	LABOR_M	TOTAL	3,961	2,370	599	201	717	43	1	25	5
Accrued Book Pension Expense	19,436	LABOR_M	TOTAL	19,436	11,631	2,938	984	3,517	213	4	122	27
Accrued Book Pension Costs - SFAS 158	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Supplemental Executive Retirement	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Acord Suppl Executive Retirement - SFAS 158	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Acord Book Supplemental Savings Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Stock Based Compensation	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Book Provision - Uncollectible Accounts	-	CUST_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Acord Companywide Incentive Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Acord Book Vacation Pay	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
(IDCP) Incentive Comp Deferral Plan	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Acord Book Severance Benefits	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset on Deferred RTO Costs	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Customer Adv Inc for Tax	134,413	TDPLANT	TOTAL	134,413	82,750	20,614	7,162	19,339	1,566	28	2,551	405
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	3,184	REV_RENT	TOTAL	3,184	2,130	520	141	342	31	1	15	3
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	(799,064)	RB_GUP	TOTAL	(799,064)	(471,013)	(117,958)	(44,812)	(141,955)	(9,718)	(172)	(11,563)	(1,873)
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	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-
Misc Fees	(62)	RB_GUP	TOTAL	(62)	(37)	(9)	(3)	(11)	(1)	(0)	(1)	(0)
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-ROCKPORTY CAPACITY DEFERRAL	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
REG ASSET-KENTUCKY UNDER RECOV-PPA RIDER	-	PROD_ENERGY	TOTAL	-	-	-	-	-	-	-	-	-

**KENTUCKY POWER COMPANY**  
**COST-OF-SERVICE STUDY**  
**TWELVE MONTHS ENDING**  
**MAY 31, 2025**

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<u>Label</u>	<u>Constant</u>	<u>Allocation Factor</u>	<u>Function</u>	<u>Total Retail</u> <u>1</u>	<u>RS</u> <u>2</u>	<u>Total GS</u>	<u>Total LGS</u>	<u>Total IGS</u>	<u>Total PS</u>	<u>MW</u> <u>16</u>	<u>OL</u> <u>17</u>	<u>SL</u> <u>18</u>
Green Hat Settlement & Liability	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Book Amortization Loss on Reacquired Debt	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Accrued SFAS 106 Post Retirement Expense	438,412	LABOR_M	TOTAL	438,412	262,350	66,278	22,204	79,329	4,801	94	2,752	604
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	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Gross Receipts - Tax Expense	-	RSale	TOTAL	-	-	-	-	-	-	-	-	-
DSIT Entry - WV Pollution Control	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
Accrued Sales & Use Tax Reserve	-	RSale	TOTAL	-	-	-	-	-	-	-	-	-
Reg Asset - Accrued SFAS 112	-	LABOR_M	TOTAL	-	-	-	-	-	-	-	-	-
Excess ADFIT 281 Protected	(545,207)	RB_GUP	TOTAL	(545,207)	(321,376)	(80,483)	(30,575)	(96,857)	(6,631)	(117)	(7,890)	(1,278)
Excess ADFIT 282 Protected and Unprotected	(2,533,118)	RB_GUP	TOTAL	(2,533,118)	(1,493,162)	(373,938)	(142,059)	(450,012)	(30,808)	(545)	(36,657)	(5,938)
Excess ADFIT 283 Unprotected	(823,816)	RB_GUP	TOTAL	(823,816)	(485,603)	(121,612)	(46,200)	(146,352)	(10,019)	(177)	(11,921)	(1,931)
Restricted Stock Plan & PSI Stock Based Comp	(15,151)	RB_GUP	TOTAL	(15,151)	(8,931)	(2,237)	(850)	(2,692)	(184)	(3)	(219)	(36)
Capitalized Software Costs Tax	521	RB_GUP	TOTAL	521	307	77	29	93	6	0	8	1
Capitalized Software Costs Book	-	RB_GUP	TOTAL	-	-	-	-	-	-	-	-	-
MTM Book Gain Above the Line Tax Deferral	962,552	PROD_ENERGY	TOTAL	962,552	349,919	114,268	71,366	404,167	15,173	340	5,857	1,462
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	(7,651)	PROD_ENERGY	TOTAL	(7,651)	(2,781)	(908)	(567)	(3,213)	(121)	(3)	(47)	(12)
<b>Total Per Books DFIT</b>	<b>7,710,806</b>			<b>7,710,806</b>	<b>4,722,812</b>	<b>1,177,440</b>	<b>409,418</b>	<b>1,159,485</b>	<b>89,349</b>	<b>1,600</b>	<b>129,737</b>	<b>20,965</b>
<b>DFIT Adjustments</b>												
Wholesale Load Adjustments - BULK TRANS	(121)	BULK_TRANS	TOTAL	(121)	(59)	(15)	(8)	(36)	(2)	(0)	(0)	(0)
Wholesale Load Adj - PROD ENERGY	13,558	PROD_ENERGY	TOTAL	13,558	4,929	1,610	1,005	5,693	214	5	83	21
Adj 26 - Pension & OPEB Expense Adjustment	(1,042,693)	LABOR_M	TOTAL	(1,042,693)	(623,957)	(157,632)	(52,808)	(188,672)	(11,419)	(223)	(6,546)	(1,436)
Wholesale Load Adj - REV RENT	22	REV_RENT	TOTAL	22	15	4	1	2	0	0	0	0
Wholesale Load Adj - FUEL REV	(20,563)	FUELREV	TOTAL	(20,563)	(7,475)	(2,441)	(1,525)	(8,634)	(324)	(7)	(125)	(31)
Wholesale Load Adj - TDPLANT	134	TDPLANT	TOTAL	134	82	21	7	19	2	0	3	0
Wholesale Load Adjustments	81	PROD_DEMAND	TOTAL	81	40	10	6	24	1	0	0	0
Adj 41 - KPCO AFUDC Offset	-	TRANS_TOTAL	TOTAL	-	-	-	-	-	-	-	-	-
Adj 18 - Remaining Wholesale Load Adjustments - RB_GUP	(16,616)	RB_GUP	TOTAL	(16,616)	(9,794)	(2,453)	(932)	(2,952)	(202)	(4)	(240)	(39)
Adj 37 & 48 - Depreciation/Amortization Adjustments - Gross Plan	2,037,892	RB_GUP-Land_P	TOTAL	2,037,892	1,015,966	259,355	136,468	593,228	28,953	494	2,738	690
Adj 37 & 48 - Depreciation/Amortization Adjustments - Trans	-	RB_GUP-Land_T	TOTAL	-	-	-	-	-	-	-	-	-
Adj 37 & 48 - Depreciation/Amortization Adjustments - Dist	-	RB_GUP-Land_D	TOTAL	-	-	-	-	-	-	-	-	-
Adj 37 & 48 - Depreciation/Amortization Adjustments - Gen & Int	-	RB_GUP-Land_G	TOTAL	-	-	-	-	-	-	-	-	-
Excess ADFIT 281 Protected	545,207	RB_GUP	TOTAL	545,207	321,376	80,483	30,575	96,857	6,631	117	7,890	1,278
Excess ADFIT 282 Protected and Unprotected	2,533,118	RB_GUP	TOTAL	2,533,118	1,493,162	373,938	142,059	450,012	30,808	545	36,657	5,938
Excess ADFIT 283 Unprotected	823,816	RB_GUP	TOTAL	823,816	485,603	121,612	46,200	146,352	10,019	177	11,921	1,931
Adj 41 - AFUDC Offset	-	PROD_DEMAND	TOTAL	-	-	-	-	-	-	-	-	-
<b>Total Adjustments to DFIT</b>	<b>4,873,835</b>		<b>TOTAL</b>	<b>4,873,835</b>	<b>2,679,886</b>	<b>674,491</b>	<b>301,048</b>	<b>1,091,893</b>	<b>64,680</b>	<b>1,104</b>	<b>52,379</b>	<b>8,353</b>
<b>Total Deferred FIT</b>	<b>12,584,641</b>		<b>TOTAL</b>	<b>12,584,641</b>	<b>7,402,698</b>	<b>1,851,931</b>	<b>710,466</b>	<b>2,251,378</b>	<b>154,029</b>	<b>2,705</b>	<b>182,117</b>	<b>29,318</b>
<b>Feedback Prior ITC Normalization Tax</b>	-	RB_GUP	<b>TOTAL</b>	-	-	-	-	-	-	-	-	-
<b>Total Federal Income Tax</b>	<b>9,849,130</b>		<b>TOTAL</b>	<b>9,849,130</b>	<b>(1,097,914)</b>	<b>4,494,744</b>	<b>3,187,913</b>	<b>1,288,770</b>	<b>883,435</b>	<b>15,377</b>	<b>890,540</b>	<b>186,265</b>
<b>Total Income Tax</b>	<b>8,451,113</b>		<b>TOTAL</b>	<b>8,451,113</b>	<b>(1,938,622)</b>	<b>4,295,728</b>	<b>3,115,866</b>	<b>1,039,259</b>	<b>868,275</b>	<b>15,109</b>	<b>872,116</b>	<b>183,382</b>
<b>Total Expenses</b>	<b>589,874,740</b>		<b>TOTAL</b>	<b>589,874,740</b>	<b>285,126,664</b>	<b>82,426,774</b>	<b>39,992,151</b>	<b>167,205,774</b>	<b>8,714,238</b>	<b>172,719</b>	<b>5,174,530</b>	<b>1,061,889</b>
<b>Net Operating Income</b>	<b>75,590,765</b>		<b>TOTAL</b>	<b>75,590,765</b>	<b>16,876,165</b>	<b>22,278,830</b>	<b>14,320,560</b>	<b>13,662,865</b>	<b>3,839,420</b>	<b>66,967</b>	<b>3,774,345</b>	<b>771,613</b>
<b>AFUDC Offset</b>												
Production	559,182	PROD_DEMAND	TOTAL	559,182	274,191	70,191	38,078	167,588	8,067	137	745	185
Transmission	3,777,546	RB_GUP_EPIS_T	TOTAL	3,777,546	1,836,347	471,597	258,729	1,149,630	54,805	918	4,421	1,098
Distribution	1,362,048	RB_GUP_EPIS_D	TOTAL	1,362,048	975,562	239,061	56,476	26,194	12,845	244	44,687	6,979
General & Intangible	267,410	LABOR_M	TOTAL	267,410	160,021	40,426	13,543	48,387	2,929	57	1,679	368
<b>Total Per Books AFUDC Offset</b>	<b>5,966,186</b>		<b>TOTAL</b>	<b>5,966,186</b>	<b>3,246,120</b>	<b>821,275</b>	<b>366,827</b>	<b>1,391,799</b>	<b>78,646</b>	<b>1,356</b>	<b>51,532</b>	<b>8,631</b>
Adj 18 - Wholesale Load General AFUDC	5,458	LABOR_M	TOTAL	5,458	3,266	825	276	988	60	1	34	8
Adj 18 - Wholesale Load Distribution AFUDC	1,364	RB_GUP_EPIS_D	TOTAL	1,364	977	239	57	26	13	0	45	7
Adj 18 - Wholesale Load Transmission AFUDC	57,526	RB_GUP_EPIS_T	TOTAL	57,526	27,965	7,182	3,940	17,507	835	14	67	17
Adj 18 - Wholesale Load Production AFUDC	8,516	PROD_DEMAND	TOTAL	8,516	4,176	1,069	580	2,552	123	2	11	3
Adj 41 - AFUDC Offset	3,940,450	PROD_DEMAND	TOTAL	3,940,450	1,932,172	494,619	268,329	1,180,963	56,848	968	5,247	1,303

**KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025**

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<u>Label</u>	<u>Constant</u>	<u>Allocation Factor</u>	<u>Function</u>	<u>Total Retail 1</u>	<u>RS 2</u>	<u>Total GS</u>	<u>Total LGS</u>	<u>Total IGS</u>	<u>Total PS</u>	<u>MW 16</u>	<u>OL 17</u>	<u>SL 18</u>
Total AFUDC Offset Adjustments	4,013,313		TOTAL	4,013,313	1,968,555	503,935	273,182	1,202,036	57,878	985	5,405	1,337
Total Adjusted AFUDC Offsets	9,979,499		TOTAL	9,979,499	5,214,675	1,325,210	640,009	2,593,836	136,524	2,342	56,937	9,968
<b>Adjusted Net Operating Income</b>	85,570,264		TOTAL	85,570,264	22,090,840	23,604,040	14,960,568	16,256,701	3,975,944	69,309	3,831,282	781,581
<b>Current Rate of Return</b>				4.57%	2.05%	8.66%	14.02%	4.52%	16.77%	16.36%	14.08%	17.58%
<b><u>O&amp;M Labor</u></b>												
Production Demand	7,984,127	PROD_DEMAND	TOTAL	7,984,127	3,914,960	1,002,196	543,688	2,392,864	115,186	1,961	10,632	2,640
Production Energy	5,758,873	PROD_ENERGY	TOTAL	5,758,873	2,093,537	683,655	426,976	2,418,097	90,781	2,037	35,043	8,748
Transmission	2,972,212	EXP_OM_TRAN	TOTAL	2,972,212	1,444,681	371,029	203,587	904,733	43,124	722	3,472	863
Distribution	13,546,394	EXP_OM_DIST	TOTAL	13,546,394	10,084,936	2,492,767	483,017	226,593	108,865	2,203	115,660	32,352
Customer Accounts	2,368,675	EXP_OM_CUSTACCT	TOTAL	2,368,675	1,982,063	383,879	5,729	823	1,624	95	(6,117)	579
Customer Service	214,599	EXP_OM_CUSTSERV	TOTAL	214,599	134,499	31,886	447	61	132	8	47,511	55
Total	32,844,880		TOTAL	32,844,880	19,654,677	4,965,412	1,663,444	5,943,171	359,713	7,026	206,202	45,236
<b><u>Adjusted Fuel &amp; Purchased Power</u></b>												
Adjusted Purchase Power Demand	5,008,293	PROD_DEMAND	TOTAL	5,008,293	2,455,781	628,659	341,045	1,500,998	72,254	1,230	6,670	1,656
Adjusted Purchase Power Energy & Fuel	258,705,723	PROD_ENERGY	TOTAL	258,705,723	94,047,933	30,711,810	19,181,024	108,628,111	4,078,131	91,488	1,574,243	392,982
<b><u>Calculation of Proposed Revenues</u></b>												
Proposed Operating Income	141,804,920	RATEBASE	TOTAL	141,804,919	46,896,377	32,647,514	19,656,284	31,840,685	5,080,779	90,096	4,648,478	944,706
					46,896,377	32,647,514	19,656,284	31,840,685	5,080,779	90,096	4,648,478	944,706
<b>Proposed Rate of Return</b>				7.57%	4.35%	11.97%	18.42%	8.85%	21.43%	21.26%	17.09%	21.25%
<b>Income Increase</b>	56,234,656		TOTAL	56,234,655	24,805,537	9,043,474	4,695,716	15,583,984	1,104,835	20,787	817,196	163,125
<b>Gross Revenue Conversion Factor</b>	1.33849											
<b>Revenue Increase</b>	75,269,689		TOTAL	75,269,687	33,202,036	12,104,626	6,285,182	20,859,053	1,478,814	27,823	1,093,811	218,342
<b>Percent Revenue Increase</b>				12.61%	12.29%	12.66%	12.68%	13.11%	12.76%	12.55%	12.56%	12.26%
<b>Proposed Sales Revenue</b>	672,038,792		TOTAL	672,038,791	303,342,975	107,685,273	55,863,752	180,027,107	13,071,489	249,488	9,799,312	1,999,395



KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

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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
XXXXXXXXXXXXXXXXXXXXX																		
BULK_TRANS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS BULKTRAN	1.00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
BULK_TRANS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS TOTAL	1.00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
CUST_902 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_902 CUSTOMER	1.00000000	0.73179529	0.25961466	0.00068822	0.00003090	0.00460121	0.00084271	0.00009832	0.00002809	0.00008427	0.00057304	0.00028652	0.00005056	0.00125002	0.00001124	0.00004494	-	-
CUST_902 TOTAL	1.00000000	0.73179529	0.25961466	0.00068822	0.00003090	0.00460121	0.00084271	0.00009832	0.00002809	0.00008427	0.00057304	0.00028652	0.00005056	0.00125002	0.00001124	0.00004494	-	-
CUST_903 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903 CUSTOMER	1.00000000	0.84269846	0.15354312	0.00034857	0.00001508	0.00181448	0.00029913	0.00003477	0.00001005	0.00002472	0.00016968	0.00008463	0.00001508	0.00063304	0.00000503	0.00003980	-	0.00026436
CUST_903 TOTAL	1.00000000	0.84269846	0.15354312	0.00034857	0.00001508	0.00181448	0.00029913	0.00003477	0.00001005	0.00002472	0.00016968	0.00008463	0.00001508	0.00063304	0.00000503	0.00003980	-	0.00026436
CUST_DEP_FXNL PRODUCTION	0.20780023	0.12226744	0.02693818	0.00197001	0.00023953	0.00915569	0.01061939	0.00239321	0.00014882	0.00156174	0.01193067	0.01580422	0.00450155	0.00019752	-	-	0.00007225	-
CUST_DEP_FXNL BULKTRAN	0.22007193	0.12948798	0.02852903	0.00208635	0.00025367	0.00969638	0.01124652	0.00253454	0.00015761	0.00165397	0.01263524	0.01673755	0.00476739	0.00020919	-	-	0.00007651	-
CUST_DEP_FXNL SUBTRAN	0.08264333	0.04807628	0.01071888	0.00078131	0.00012642	0.00379492	0.00438079	0.00127791	-	0.00060351	0.00488789	0.00789720	-	0.00008186	-	-	0.00001634	-
CUST_DEP_FXNL DISTPRI	0.16999872	0.11212003	0.02458536	0.00179458	-	0.00861194	0.00995656	-	-	0.00139473	0.01130442	-	-	0.00018576	-	-	0.00004533	-
CUST_DEP_FXNL DISTSEC	0.05619148	0.04454308	0.00870913	-	-	0.00249382	-	-	-	0.00031343	-	-	-	0.00005517	-	-	0.00007685	-
CUST_DEP_FXNL ENERGY	0.00854825	0.00409215	0.00115039	0.00008238	0.00001030	0.00045220	0.00051406	0.00011590	0.00000700	0.00008956	0.00071655	0.00100475	0.00029235	0.00000975	-	-	0.00001490	-
CUST_DEP_FXNL CUSTOMER	0.25474608	0.20327651	0.04277559	0.00167167	0.00107083	0.00052979	0.00074257	0.00093736	0.00011828	0.00002144	0.00022408	0.00008271	0.00003721	0.00001435	-	-	0.00324369	-
CUST_DEP_FXNL TOTAL	1.00000000	0.66386348	0.14340656	0.00638631	0.00170076	0.03473474	0.03745989	0.00725892	0.00043171	0.00563440	0.04169885	0.04152643	0.00959850	0.00075360	-	-	0.00354587	-
CUST_SPEC_FXNL PRODUCTION	0.43116766	-	-	-	-	-	0.18029179	-	-	-	-	-	-	0.25087586	-	-	-	-
CUST_SPEC_FXNL BULKTRAN	(0.00287034)	-	-	-	-	-	0.03239451	-	-	-	-	-	-	(0.03526485)	-	-	-	-
CUST_SPEC_FXNL SUBTRAN	0.01228423	-	-	-	-	-	0.01228423	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL DISTPRI	0.07370455	-	-	-	-	-	0.07370455	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_FXNL ENERGY	0.47846449	-	-	-	-	-	0.14851697	-	-	-	-	-	-	0.32994752	-	-	-	-
CUST_SPEC_FXNL CUSTOMER	0.00724942	-	-	-	-	-	0.00649132	-	-	-	-	-	-	0.00075810	-	-	-	-
CUST_SPEC_FXNL TOTAL	1.00000000	-	-	-	-	-	0.45368337	-	-	-	-	-	-	0.54631663	-	-	-	-
CUST_SPEC_OM PRODUCTION	0.28479316	-	-	-	-	-	0.13844906	-	-	-	-	-	-	0.14634410	-	-	-	-
CUST_SPEC_OM BULKTRAN	0.02278317	-	-	-	-	-	0.01124494	-	-	-	-	-	-	0.01153823	-	-	-	-
CUST_SPEC_OM SUBTRAN	0.00438002	-	-	-	-	-	0.00438002	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM DISTPRI	0.02253762	-	-	-	-	-	0.02253762	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC_OM ENERGY	0.66166663	-	-	-	-	-	0.27366034	-	-	-	-	-	-	0.38800628	-	-	-	-
CUST_SPEC_OM CUSTOMER	0.00363941	-	-	-	-	-	0.00341139	-	-	-	-	-	-	0.00042802	-	-	-	-
CUST_SPEC_OM TOTAL	1.00000000	-	-	-	-	-	0.45368337	-	-	-	-	-	-	0.54631663	-	-	-	-
CUST_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL CUSTOMER	1.00000000	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00028870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501
CUST_TOTAL TOTAL	1.00000000	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00028870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501
DIST_CPD PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD DISTPRI	1.00000000	0.66449865	0.16729526	0.00195228	-	0.07214235	0.02047965	-	-	0.00411454	0.04759045	-	-	0.01957822	0.00046908	0.00033684	0.00123474	0.00030793
DIST_CPD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD TOTAL	1.00000000	0.66449865	0.16729526	0.00195228	-	0.07214235	0.02047965	-	-	0.00411454	0.04759045	-	-	0.01957822	0.00046908	0.00033684	0.00123474	0.00030793
DIST_METERS PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_METERS CUSTOMER	1.00000000	0.61433085	0.25763124	0.02079895	0.00370977	0.01872532	0.01732500	0.01064449	0.00456183	0.00029258	0.01104026	0.02760148	0.00684278	0.00598137	0.00020244	0.00031164	-	-
DIST_METERS TOTAL	1.00000000	0.61433085	0.25763124	0.02079895	0.00370977	0.01872532	0.01732500	0.01064449	0.00456183	0.00029258	0.01104026	0.02760148	0.00684278	0.00598137				

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

Exhibit No.: NMC-1  
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Witness: N. Coon

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_OHINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHINES DISTPRI	0.24880464	0.16533035	0.04162384	0.00048574	-	0.01794935	0.00509543	-	-	0.00102372	0.01184072	-	-	0.00487115	0.00011671	0.00008381	0.00030721	0.00007661
DIST_OHINES DISTSEC	0.10562585	0.07886044	0.01770312	-	-	0.00624054	-	-	-	0.00027621	-	-	-	0.00173683	-	0.00002832	0.00062538	0.00015500
DIST_OHINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OHINES CUSTOMER	0.64556951	0.51976035	0.12292819	0.00027932	-	0.00145246	0.00023942	-	-	0.00001995	0.00013567	-	-	0.00050676	0.00000399	0.00003192	-	0.00021148
DIST_OHINES TOTAL	1.00000000	0.76395114	0.18225515	0.00076505	-	0.02564235	0.00533485	-	-	0.00131988	0.01197639	-	-	0.00711475	0.00012070	0.00014405	0.00093259	0.00044310
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	0.62684132	0.14825384	0.00033686	-	0.00175169	0.00028874	-	-	0.00002406	0.00016362	-	-	0.00061117	0.00000481	0.00003850	0.22143032	0.00025505
DIST_PCUST TOTAL	1.00000000	0.62684132	0.14825384	0.00033686	-	0.00175169	0.00028874	-	-	0.00002406	0.00016362	-	-	0.00061117	0.00000481	0.00003850	0.22143032	0.00025505
DIST_POLES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES DISTPRI	0.57249889	0.38042474	0.09577635	0.00111768	-	0.04130142	0.01172458	-	-	0.00235557	0.02724548	-	-	0.01120851	0.00026855	0.00019284	0.00070689	0.00017629
DIST_POLES DISTSEC	0.42750111	0.31917308	0.07165013	-	-	0.02525743	-	-	-	0.00111791	-	-	-	0.00702952	-	0.00011463	0.00253110	0.00062732
DIST_POLES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES TOTAL	1.00000000	0.69959782	0.16742648	0.00111768	-	0.06655884	0.01172458	-	-	0.00347348	0.02724548	-	-	0.01823803	0.00026855	0.00030746	0.00323799	0.00080361
DIST_SERV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SERV CUSTOMER	1.00000000	0.62733945	0.14837165	-	-	0.00175308	-	-	-	0.00002408	-	-	-	0.00061165	-	0.00003853	0.22160629	0.00025526
DIST_SERV TOTAL	1.00000000	0.62733945	0.14837165	-	-	0.00175308	-	-	-	0.00002408	-	-	-	0.00061165	-	0.00003853	0.22160629	0.00025526
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	0.22975388	0.15267114	0.03843674	0.00044854	-	0.01657499	0.00470528	-	-	0.00094533	0.01093409	-	-	0.00449817	0.00010777	0.00007739	0.00028369	0.00007075
DIST_TRANSF DISTSEC	0.39009459	0.29124531	0.06538071	-	-	0.02304739	-	-	-	0.00102009	-	-	-	0.00641443	-	0.00010460	0.00230963	0.00057243
DIST_TRANSF ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_TRANSF CUSTOMER	0.38015153	0.30637972	0.07246167	-	-	0.00085617	-	-	-	0.00001176	-	-	-	0.00029872	-	0.00001882	-	0.00012466
DIST_TRANSF TOTAL	1.00000000	0.75029618	0.17627912	0.00044854	-	0.04047855	0.00470528	-	-	0.00197718	0.01093409	-	-	0.01121132	0.00010777	0.00020080	0.00259331	0.00076784
DIST_UGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES DISTPRI	0.24643633	0.16375661	0.04122763	0.00048111	-	0.01777850	0.00504693	-	-	0.00101397	0.01172802	-	-	0.00482478	0.00011560	0.00008301	0.00030429	0.00007589
DIST_UGLINES DISTSEC	0.33748496	0.25196687	0.05656322	-	-	0.01993913	-	-	-	0.00068252	-	-	-	0.00554936	-	0.00009049	0.00199814	0.00049523
DIST_UGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_UGLINES CUSTOMER	0.41607871	0.33499292	0.07922896	0.00018002	-	0.00093613	0.00015431	-	-	0.00001286	0.00008744	-	-	0.00032862	0.00000257	0.00002057	-	0.00013630
DIST_UGLINES TOTAL	1.00000000	0.75071639	0.17701981	0.00066114	-	0.03865376	0.00520124	-	-	0.00190935	0.01181546	-	-	0.01070076	0.00011817	0.00019407	0.00230243	0.00070742
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	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00020043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436
EXP_OM_CUSTACCT TOTAL	1.00000000	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00020043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436

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Allocation	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
Factor	Retail	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	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	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00022870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501
EXP_OM_CUSTSERV TOTAL	1.00000000	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00022870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501
EXP_OM_DIST PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST DISTPRI	0.28190956	0.18732852	0.04716213	0.00055037	-	0.02033762	0.00577341	-	-	0.00115993	0.01341620	-	-	0.00551929	0.00013224	0.00009496	0.00034809	0.00008581
EXP_OM_DIST DISTSEC	0.10340798	0.07720458	0.01733141	-	-	0.00610950	-	-	-	0.00027041	-	-	-	0.00170037	-	0.00002773	0.00061225	0.00015674
EXP_OM_DIST ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_DIST CUSTOMER	0.61468246	0.47994075	0.11780050	0.00103098	0.00014167	0.00199072	0.00086450	0.000040650	0.00017421	0.00002870	0.00053658	0.00105407	0.00026132	0.00067349	0.00001111	0.00003994	0.00757775	0.00214966
EXP_OM_DIST TOTAL	1.00000000	0.74447386	0.18229404	0.00158134	0.00014167	0.02843785	0.00663791	0.000040650	0.00017421	0.00145903	0.01395278	0.00105407	0.00026132	0.00789314	0.00014335	0.00016262	0.00853808	0.00238822
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	(0.00000000)
EXP_OM_TRAN BULKTRAN	0.72290000	0.35441986	0.08965444	0.00104820	0.00002582	0.03751254	0.01068339	0.00084544	0.00017846	0.00225339	0.02456590	0.16406678	0.02573898	0.01018192	0.00024580	0.00017752	0.00096255	0.00023902
EXP_OM_TRAN SUBTRAN	0.27720000	0.13164278	0.03368681	0.00039270	0.00001287	0.01468749	0.00416314	0.00042644	-	0.00082257	0.00950711	0.07744253	-	0.00398610	0.00099537	0.00006546	0.00020582	0.00005122
EXP_OM_TRAN DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EXP_OM_TRAN TOTAL	1.00000000	0.48606284	0.12335305	0.00144089	0.00003870	0.05220004	0.01484652	0.00127188	0.00017846	0.00307596	0.03407302	0.24150930	0.02573898	0.01416803	0.00034117	0.00024298	0.00116816	0.00029024
EXP_OM_LPP PRODUCTION	0.72555303	0.35602950	0.08999370	0.00096002	0.00001742	0.03745986	0.01077509	0.00003431	0.00053619	0.00227877	0.02481970	0.16405872	0.02599747	0.01015389	0.00024815	0.00017973	0.00098445	0.00024205
EXP_OM_LPP BULKTRAN	0.06003453	0.02967624	0.00754486	0.00007422	(0.00000106)	0.00313905	0.00091144	0.00007057	(0.00006296)	0.00019016	0.00208637	0.01382550	0.00213456	0.00084722	0.00002094	0.00001526	0.00008155	0.00002062
EXP_OM_LPP SUBTRAN	0.02327537	0.01102637	0.00283569	0.00002796	(0.00000043)	0.00122913	0.00035501	0.00003560	-	0.00006940	0.00080719	0.00652513	-	0.00033175	0.00000812	0.00000562	0.00001742	0.00000442
EXP_OM_LPP DISTPRI	0.08804422	0.05853073	0.01473656	0.00013684	-	0.00628486	0.00182674	-	-	0.00038767	0.00425303	-	-	0.00169859	0.00004190	0.00003032	0.00010944	0.00002776
EXP_OM_LPP DISTSEC	0.03226362	0.02410639	0.00541157	-	-	0.00188726	0.00008561	-	-	0.00003651	0.00023232	-	-	0.00023232	0.00000884	0.00001920	0.00004845	-
EXP_OM_LPP ENERGY	(0.05939045)	(0.01924042)	(0.00028722)	(0.00001218)	(0.00948243)	(0.00255819)	(0.00021858)	0.00056713	(0.00060334)	(0.00724453)	(0.05318099)	(0.00818256)	(0.00258322)	(0.00005820)	(0.00056533)	(0.00095920)	(0.00024190)	-
EXP_OM_LPP CUSTOMER	0.23459193	0.1848507	0.04345518	0.00028693	0.00002026	0.00069196	0.00027650	0.00012047	(0.00006364)	0.00001013	0.00001129	0.00007918	0.00023347	0.00000361	0.00001419	0.00038625	0.00073811	-
EXP_OM_LPP TOTAL	1.00000000	0.60482634	0.14473714	0.00119875	0.00002401	0.04120948	0.01158659	0.00084236	0.00043672	0.00239841	0.02489305	0.13154583	0.02002866	0.01120579	0.00026452	0.00019763	0.00376520	0.00083951
FORF_DISC_FXNL PRODUCTION	0.37973260	0.00004474	0.17152379	0.00208064	0.00023699	0.02838581	0.05283229	0.00408197	-	(0.00710968)	0.05085154	0.07659837	-	-	-	-	0.00020615	-
FORF_DISC_FXNL BULKTRAN	0.01669593	(0.00000584)	0.00540330	0.00032169	0.00009075	0.00368618	0.00949281	0.00017056	-	(0.00022172)	0.00498410	(0.00733561)	-	-	-	-	0.00002972	-
FORF_DISC_FXNL SUBTRAN	0.00567050	(0.0000211)	0.0198831	0.00011703	0.00004258	0.00139964	0.00359974	0.00089312	-	(0.00077909)	0.0188044	(0.00336538)	-	-	-	-	0.00000619	-
FORF_DISC_FXNL DISTPRI	0.10402933	0.00001018	0.05426982	0.00079635	-	0.01084273	0.02159821	-	-	(0.00224042)	0.01866269	-	-	-	-	-	0.00005360	-
FORF_DISC_FXNL DISTSEC	0.02207889	0.00000412	0.01933929	-	-	0.00314282	-	-	-	(0.00049825)	-	-	-	-	-	-	0.00009092	-
FORF_DISC_FXNL ENERGY	0.02599781	0.00003017	0.13533823	0.00150967	0.00018405	0.02448882	0.04352107	0.00365558	-	(0.00720404)	0.05437365	0.09636499	-	-	-	-	0.00073563	-
FORF_DISC_FXNL CUSTOMER	0.11889493	0.00002405	0.10988726	0.00088517	0.00063489	0.00767634	0.00190220	0.00072675	-	(0.00004068)	0.00054494	0.00015541	-	-	-	-	0.00301449	-
FORF_DISC_FXNL TOTAL	1.00000000	0.00010530	0.49774998	0.00571055	0.00118925	0.07268945	0.13294632	0.00871798	-	(0.01735771)	0.13120736	0.16241781	-	-	-	-	0.00462370	-
FUELREV PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV ENERGY	1.00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
FUELREV CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELREV TOTAL	1.00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
LABOR_M PRODUCTION	0.24308589	0.11919545	0.03015181	0.00032552	0.00000868	0.01261590	0.00359295	0.00028433	0.00006002	0.00057584	0.00826179	0.05517753	0.00866531	0.00342430	0.00008286	0.00059070	0.00032372	0.00008038
LABOR_M BULKTRAN	0.06540791	0.03207230	0.00811305	0.00009485	0.00000234	0.00339460	0.00099677	0.00007651	0.00001615	0.00023091	0.01484680	0.00222303	0.000232918	0.00002224	0.00001606	0.00008710	0.00000163	-
LABOR_M SUBTRAN	0.02508449	0.01191267	0.00304947	0.00035054	0.00000117	0.00132911	0.00037673	0.00003859	-	0.00007444	0.00086032	0.00700796	-	0.00036071	0.00000883	0.00001861	0.00000464	-
LABOR_M DISTPRI	0.11626951	0.07726993	0.01945134	0.00022699	-	0.00368796	0.00238116	-	-	0.00047840	0.00055332	-	-	0.00227635	0.00005454	0.00003916	0.00014356	0.00003580
LABOR_M DISTSEC	0.04264912	0.03184191	0.00714809	-	-	0.00251978	-	-	-	0.00011153	-	-	-	0.00070129	-	0.00001144	0.00025251	0.00002658
LABOR_M ENERGY	0.75334569	0.06374014	0.02057316	0.00023552	0.00000597	0.00995572	0.00277894	0.00022001	0.00004510	0.00066339	0.00792811	0.05604800	0.00988223	0.00270045	0.00006347	0.00006201	0.00106693	0.00026634
LABOR_M CUSTOMER	0.13216759	0.26238574	0.06121304	0.00045442	0.00005970	0.00097868	0.00038300	0.00017073	0.00007724	0.00001410	0.00023683	0.00044249	0.00010915	0.00033082	0.00000501	0.00001962	0.00438562	0.00090589
LABOR_M TOTAL	1.00000000	0.59840915	0.14969995	0.00139885	0.00007786	0.03918174	0.01047954	0.00079017	0.00019401	0.00230361	0.02504339	0.13352277	0.02007888	0.01071530	0.00023656	0.00021392	0.00627805	0.00137726
LABOR_PROD PRODUCTION	0.58095954	0.28486940	0.07206088	0.00084250	0.00002076	0.03015118	0.00858691	0.00067953	0.00014344	0.00181119	0.01974515	0.13187072	0.02068802	0.00818385	0.00019756	0.00014288	0.00077366	0.00019211
LABOR_PROD BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD ENERGY	0.41904046	0.15233482	0.04916852	0.00056289	0.00001427	0.02379352	0.00664148	0.00052581	0.00010779	0.00158547	0.01894766	0.13395108	0.02146696	0.00645389	0.00015			

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

Exhibit No.: NMC-1  
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Witness: N. Coon

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	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
PROD_DEMAND BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND TOTAL	1.00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
PROD_ENERGY PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY ENERGY	1.00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
PROD_ENERGY CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY TOTAL	1.00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
RATEBASE PRODUCTION	0.19458320	0.09501480	0.02411350	0.00025329	0.00000279	0.01013613	0.00273018	0.00018698	0.00003459	0.00058862	0.00651512	0.04478778	0.00697929	0.00279537	0.00006747	0.00004872	0.00026296	0.00006559
RATEBASE BULKTRAN	0.24773133	0.12105331	0.03070130	0.00032591	0.00000426	0.01288919	0.00350810	0.00024625	0.00007924	0.00075373	0.00831969	0.0586016	0.00888048	0.00354492	0.00008566	0.00006186	0.00033399	0.00008329
RATEBASE SUBTRAN	0.09254060	0.04378000	0.01123692	0.00011857	0.00000201	0.00491457	0.00132966	0.00012038	-	0.00026775	0.00313434	0.02614296	-	0.00135196	0.00003238	0.00002222	0.00006950	0.00001739
RATEBASE DISTPRI	0.14342783	0.09532290	0.02406821	0.00025320	-	0.01041917	0.00261288	-	-	0.00057668	0.00676234	-	-	0.00286892	0.00006878	0.00004938	0.00018022	0.00004514
RATEBASE DISTSEC	0.04986925	0.03719731	0.00837495	-	-	0.00296303	-	-	-	0.00012274	-	-	-	0.00083718	0.00001366	0.00003022	0.00007475	-
RATEBASE ENERGY	0.04899543	0.01815152	0.00586426	0.00006799	0.00000173	0.00284539	0.00078395	0.00000615	(0.00000701)	0.00018762	0.00224912	0.01604164	0.00255728	0.00001812	0.00001769	0.000030473	0.00007597	-
RATEBASE CUSTOMER	0.22183236	0.16485778	0.04003426	0.00022533	0.00001373	0.00061418	0.00020069	0.00007813	0.00004262	0.00000848	0.00012850	0.00024727	0.00006094	0.00021254	0.00000280	0.00001280	0.00130802	0.00021202
RATEBASE TOTAL	1.00000000	0.57537763	0.14439340	0.00024430	0.000002451	0.04478257	0.01136546	0.00069289	0.00014945	0.00251013	0.02710911	0.14407981	0.01847799	0.00027522	0.00022633	0.01453190	0.00237415	-
RB_GUP_CWIP PRODUCTION	0.06214190	0.03047084	0.00770794	0.00009012	0.00000222	0.00322510	0.00091849	0.00007269	0.00001534	0.00019373	0.00211203	0.01410545	0.00221288	0.00087538	0.00002113	0.00001526	0.00008275	0.00002055
RB_GUP_CWIP BULKTRAN	0.43190099	0.21177959	0.05357200	0.00062634	0.00001543	0.02241520	0.00638374	0.00050518	0.00010663	0.00134649	0.01467908	0.09803625	0.01538004	0.00608409	0.00014087	0.00010607	0.00057516	0.00014282
RB_GUP_CWIP SUBTRAN	0.16556811	0.07862859	0.02012776	0.00023455	0.00000769	0.00877266	0.00248659	0.00025471	-	0.00049131	0.00567848	0.04625546	-	0.00238085	0.00005696	0.00003910	0.00012281	0.00003059
RB_GUP_CWIP DISTPRI	0.11633322	0.07730327	0.01946200	0.00022711	-	0.00830255	0.00238246	-	-	0.00047866	0.00553635	-	-	0.00227760	0.00005457	0.00003919	0.00014364	0.00003582
RB_GUP_CWIP DISTSEC	0.04101885	0.03062474	0.00687485	-	-	0.00242346	-	-	-	0.00010726	-	-	-	0.00067448	-	0.00001100	0.00024286	0.00006019
RB_GUP_CWIP ENERGY	0.00167954	0.00061057	0.00019707	0.000000226	0.00000006	0.00002662	0.00000211	0.00000043	0.00000635	0.00007594	0.00053688	0.00008604	0.00002587	0.00000061	0.00000059	0.00002022	0.00000255	-
RB_GUP_CWIP CUSTOMER	0.18135740	0.13493390	0.03268941	0.00020324	0.00002647	0.00049818	0.00017064	0.00007596	0.00003255	0.00000710	0.00010542	0.00019696	0.00004882	0.00016986	0.00000223	0.00001023	0.01056860	0.00161784
RB_GUP_CWIP TOTAL	1.00000000	0.56435150	0.14063102	0.00138362	0.00005187	0.04582250	0.01236854	0.00091064	0.00015496	0.00263090	0.02818730	0.15913100	0.01772778	0.01248813	0.00028237	0.00022144	0.01174605	0.00191037
RB_GUP_EPIS_D PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D DISTPRI	0.34540731	0.22952269	0.05778501	0.00067433	-	0.02491850	0.00707382	-	-	0.00142119	0.01643809	-	-	0.00676246	0.00016202	0.00011635	0.00042649	0.00010636
RB_GUP_EPIS_D DISTSEC	0.12165956	0.09083124	0.02039041	-	-	0.00718783	-	-	-	0.00031814	-	-	-	0.00200048	-	0.00003262	0.00072031	0.00017853
RB_GUP_EPIS_D ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D CUSTOMER	0.53293313	0.39589245	0.09599146	0.00059693	0.00007791	0.00146351	0.00050110	0.00022355	0.00009580	0.00020285	0.00030963	0.00057966	0.00014371	0.00004993	0.00000654	0.00003007	0.03166188	0.00483906
RB_GUP_EPIS_D TOTAL	1.00000000	0.71624638	0.17416688	0.00127126	0.00007791	0.03356984	0.00757492	0.00022355	0.00009580	0.00176018	0.01674772	0.00057966	0.00014371	0.00926197	0.00016856	0.00017903	0.03280868	0.00512395
RB_GUP_EPIS_G PRODUCTION	0.24308589	0.11919545	0.03015181	0.00035252	0.00000868	0.01261590	0.00359295	0.00028433	0.00006002	0.00057584	0.00826179	0.05517753	0.00865631	0.00342430	0.00008266	0.00005970	0.00032372	0.00008038
RB_GUP_EPIS_G BULKTRAN	0.06540791	0.03207230	0.00811305	0.00039460	0.00000234	0.00339460	0.00096677	0.00007651	0.00001615	0.00020391	0.00222303	0.01484680	0.00232918	0.000092139	0.00002224	0.00001606	0.00008710	0.00002163
RB_GUP_EPIS_G SUBTRAN	0.02504849	0.01191267	0.00304947	0.00003554	0.00000117	0.00132911	0.00037673	0.00003859	-	0.00007444	0.00086032	0.00700796	-	0.00038071	0.00000592	0.00001881	0.00004044	-
RB_GUP_EPIS_G DISTPRI	0.11626951	0.07726093	0.01945134	0.00022699	-	0.00838796	0.00238116	-	-	0.00047840	0.00553332	-	-	0.00227635	0.00005464	0.00003916	0.00014356	0.00003590
RB_GUP_EPIS_G DISTSEC	0.04264912	0.03184191	0.00714809	-	-	0.00251978	-	-	-	0.00011153	-	-	-	0.00070129	-	0.00001144	0.00025251	0.00006258
RB_GUP_EPIS_G ENERGY	0.17533549	0.06374014	0.02057316	0.00023552	0.00000597	0.00995572	0.00277894	0.00022001	0.00004510	0.00066339	0.00792811	0.05604800	0.00898223	0.00270045	0.00006347	0.00006201	0.00106693	0.00026334
RB_GUP_EPIS_G CUSTOMER	0.33216759	0.26238574	0.06121304	0.00045442	0.00005970	0.00097868	0.00038300	0.00017073	0.00007274	0.00001410	0.00023683	0.00044249	0.00010915	0.00033082	0.00000501	0.00001962	0.00438562	0.00090589
RB_GUP_EPIS_G TOTAL	1.00000000	0.59840915	0.14969995	0.00139985	0.00007786	0.03918174	0.01047954	0.00079017	0.00019401	0.00230361	0.02504339	0.13352277	0.02007684	0.01071530	0.00023656	0.00021392	0.00627805	0.00137726
RB_GUP_EPIS_P PRODUCTION	0.94529028	0.46351639	0.11725162	0.00137085	0.00003377	0.04050955	0.01397192	0.00110567	0.00023339	0.00294702	0.03212771	0.21456935	0.03366188	0.01331610	0.00032146	0.00023216	0.00125884	0.00031259
RB_GUP_EPIS_P BULKTRAN	0.01664951	0.00816397	0.00205517	0.00002414	0.00000059	0.00006409	0.00024609	0.00001947	0.00000411	0.00005191	0.00056587	0.00377924	0.00059289	0.00023544	0.00000566	0.00004049	0.00002217	0.00000551
RB_GUP_EPIS_P SUBTRAN	0.00638523	0.00303236	0.00077624	0.00000905	0.00000030	0.00033832	0.00009590	0.00000982	-	0.00001895	0.00021899	0.00178387	-	0.00009182	0.00000220	0.00000151	0.00000474	0.00000118
RB_GUP_EPIS_P DISTPRI	0.00761242	0.00505845	0.00127352	0.00001486	-	0.00054918	0.00015590	-	-	0.00003132	0.00036228	-	-	0.00014904	0.00000357	0.00000256	0.00000940	0.00000234
RB_GUP_EPIS_P DISTSEC	0.00319536	0.00238566	0.00053555	-	-	0.00018879	-	-	-	0.00000836	-	-	-	0.00005254	-	0.00000086	0.00001892	0.00000469
RB_GUP_EPIS_P ENERGY	0.00095015	0.00034541	0.00011149	0.00000128	0.00000003	0.00005395	0.00001506	0.00000119	0.00000024	0.00000359	0.00004296	0.00003073	0.00004868	0.00001463	0.00000034	0.00000034	0.00000578	0.00000144
RB_GUP_EPIS_P CUSTOMER	0.01891704	0.01603023	0.00378152	0.00001030	0.00000032	0.00040406	0.000020879	0.00000084	0.00000059	0.00000064	0.00000240	0.00000059	0.00001601	0.00000014	0.00000010	0.00000237	0.00001084	-
RB_GUP_EPIS_P TOTAL	1.000																	

KENTUCKY POWER COMPANY  
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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	
RB_GUP-Land_T PRODUCTION	0.1408538	0.0069066	0.0017412	0.0002043	0.0000050	0.00073102	0.00020819	0.00001648	0.00000348	0.00004391	0.00047872	0.00319721	0.00050158	0.00019842	0.00000479	0.00000346	0.00001876	0.00000466
RB_GUP-Land_T BULKTRAN	0.70021951	0.34334768	0.08685361	0.00101545	0.00002502	0.03634064	0.01034964	0.00081902	0.00017288	0.00218299	0.02379846	0.15894128	0.02493488	0.00023812	0.00017197	0.00009348	0.00023155	
RB_GUP-Land_T SUBTRAN	0.28569511	0.13567712	0.03473134	0.00040473	0.00001327	0.01513761	0.00429072	0.00043951	-	0.00084777	0.00979847	0.07981584	-	0.00410826	0.00009829	0.00006746	0.00021192	0.00005279
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	0.48593147	0.12333207	0.00144061	0.00003879	0.05220926	0.01484855	0.00127501	0.00017636	0.00307468	0.03407565	0.24195433	0.02543647	0.01417052	0.00034120	0.00024289	0.00116315	0.00028900
RB_GUP-Land_D PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D DISTPRI	0.33889664	0.22519769	0.05669614	0.00066162	-	0.02444894	0.00694053	-	-	0.00139441	0.01612834	-	-	0.00663503	0.00015897	0.00011415	0.00041845	0.00010436
RB_GUP-Land_D DISTSEC	0.12286923	0.09173438	0.02059315	-	-	0.00725930	-	-	-	0.00032130	-	-	-	0.00202037	-	0.00032994	0.00072747	0.00018030
RB_GUP-Land_D ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP-Land_D CUSTOMER	0.53823213	0.39982884	0.09694591	0.00060286	0.00007868	0.00147806	0.00050608	0.00022577	0.00009676	0.00002105	0.00031271	0.00058543	0.00014514	0.00050399	0.00000660	0.00003037	0.03197670	0.00488717
RB_GUP-Land_D TOTAL	1.00000000	0.71676092	0.17423520	0.00126449	0.00007868	0.03318631	0.00744661	0.00022577	0.00009676	0.00173677	0.01644105	0.00058543	0.00014514	0.00915940	0.00016557	0.00017746	0.03312262	0.00517183
RB_GUP-Land_G PRODUCTION	0.24305859	0.11919545	0.03015181	0.00035252	0.00000868	0.01261590	0.00359295	0.00028433	0.00006002	0.00075784	0.00826179	0.05517753	0.00656531	0.00342430	0.00008266	0.00005970	0.00023272	0.00008038
RB_GUP-Land_G BULKTRAN	0.06540791	0.03207230	0.00811305	0.00009485	0.00000234	0.00339460	0.00096677	0.00007651	0.00001615	0.00020391	0.00222303	0.01484680	0.00232918	0.00092139	0.00002224	0.00001606	0.00008710	0.00002163
RB_GUP-Land_G SUBTRAN	0.02508449	0.01191267	0.00304947	0.00003554	0.00000117	0.00132911	0.00037673	0.00003859	-	0.00007444	0.00086032	0.00700796	-	0.00036071	0.00000592	0.00001861	0.00000464	
RB_GUP-Land_G DISTPRI	0.11626951	0.07726093	0.01945134	0.00022699	-	0.00838796	0.00238116	-	-	0.00047840	0.00553332	-	-	0.00227635	0.00005454	0.00003916	0.00014356	0.00003580
RB_GUP-Land_G DISTSEC	0.04269912	0.03184191	0.00714809	-	-	0.02251878	-	-	-	0.00011153	0.00026673	0.00707129	-	0.00070129	0.00001144	0.00025251	0.00002658	
RB_GUP-Land_G ENERGY	0.17533549	0.08374014	0.02057316	0.00023552	0.00000597	0.00956572	0.00277894	0.000022001	0.00004510	0.00006639	0.00792811	0.05604800	0.00988223	0.00006347	0.00006201	0.00106693	0.00026634	
RB_GUP-Land_G CUSTOMER	0.33216759	0.26238574	0.06121304	0.00045442	0.00005970	0.00097868	0.00038300	0.00017073	0.00007274	0.00001410	0.00023683	0.00044249	0.00010915	0.00033082	0.00005001	0.00001962	0.00438552	0.00009589
RB_GUP-Land_G TOTAL	1.00000000	0.59840915	0.14969995	0.00139965	0.00007786	0.03918174	0.01047954	0.00073917	0.00019401	0.00230361	0.01352277	0.02007688	0.00023656	0.00021392	0.00027805	0.00137726		
RB_GUP_EPIS PRODUCTION	0.22140306	0.10856342	0.02746232	0.00032108	0.00000791	0.01149058	0.00327246	0.00025897	0.00005466	0.00069024	0.00752486	0.05025579	0.00788418	0.00311886	0.00007529	0.00005438	0.00029484	0.00007321
RB_GUP_EPIS BULKTRAN	0.23447807	0.11487466	0.02908412	0.00034004	0.00000838	0.01216916	0.00346572	0.00027426	0.00005789	0.00073101	0.00796824	0.05322366	0.00834979	0.00330304	0.00005759	0.00003125	0.00007754	
RB_GUP_EPIS SUBTRAN	0.08988759	0.04268778	0.01092744	0.00012734	0.00000417	0.00476271	0.00134998	0.00013828	-	0.00026673	0.00308287	0.02511227	-	0.00129257	0.00003093	0.00002123	0.00006667	
RB_GUP_EPIS DISTPRI	0.14981725	0.09955336	0.02506372	0.00029248	-	0.01080817	0.00306821	-	-	0.00061643	0.00712867	-	-	0.00293315	0.00007074	0.00005046	0.00018499	0.00004613
RB_GUP_EPIS DISTSEC	0.05297415	0.03955059	0.00887858	-	-	0.00312979	-	-	-	0.00013853	-	-	-	0.00087107	-	0.00001420	0.00031364	0.00007774
RB_GUP_EPIS ENERGY	0.00999496	0.00363349	0.00117277	0.00001343	0.00000034	0.00056752	0.00015841	0.00001254	0.00000257	0.00003782	0.00045194	0.00319500	0.00051203	0.00000362	0.00000353	0.00000682	0.00001518	
RB_GUP_EPIS CUSTOMER	0.24144493	0.18049280	0.04360788	0.00027245	0.00003536	0.00002283	0.00006490	0.00010143	0.00004345	0.00000948	0.00014133	0.00026300	0.00006517	0.00022662	0.00000299	0.00001364	0.01323769	0.00203790
RB_GUP_EPIS TOTAL	1.00000000	0.58945610	0.14619684	0.00136682	0.00005616	0.04359284	0.01154360	0.00078548	0.00015857	0.00249023	0.02630011	0.13204973	0.01681117	0.01189925	0.00026284	0.00021504	0.01447091	0.00234431
RB_GUP PRODUCTION	0.22140306	0.10856342	0.02746232	0.00032108	0.00000791	0.01149058	0.00327246	0.00025897	0.00005466	0.00069024	0.00752486	0.05025579	0.00788418	0.00311886	0.00007529	0.00005438	0.00029484	0.00007321
RB_GUP BULKTRAN	0.23447807	0.11487466	0.02908412	0.00034004	0.00000838	0.01216916	0.00346572	0.00027426	0.00005789	0.00073101	0.00796824	0.05322366	0.00834979	0.00330304	0.00005759	0.00003125	0.00007754	
RB_GUP SUBTRAN	0.08988759	0.04268778	0.01092744	0.00012734	0.00000417	0.00476271	0.00134998	0.00013828	-	0.00026673	0.00308287	0.02511227	-	0.00129257	0.00003093	0.00002123	0.00006667	0.00001661
RB_GUP DISTPRI	0.14981725	0.09955336	0.02506372	0.00029248	-	0.01080817	0.00306821	-	-	0.00061643	0.00712867	-	-	0.00293315	0.00007028	0.00005046	0.00018499	0.00004613
RB_GUP DISTSEC	0.05297415	0.03955059	0.00887858	-	-	0.00312979	-	-	-	0.00013853	-	-	-	0.00087107	-	0.00001420	0.00031364	0.00007774
RB_GUP ENERGY	0.00999496	0.00363349	0.00117277	0.00001343	0.00000034	0.00056752	0.00015841	0.00001254	0.00000257	0.00003782	0.00045194	0.00319500	0.00051203	0.00000362	0.00000353	0.00000682	0.00001518	
RB_GUP CUSTOMER	0.24144493	0.18049280	0.04360788	0.00027245	0.00003536	0.00002283	0.00006490	0.00010143	0.00004345	0.00000948	0.00014133	0.00026300	0.00006517	0.00022662	0.00000299	0.00001364	0.01323769	0.00203790
RB_GUP TOTAL	1.00000000	0.58945610	0.14619684	0.00136682	0.00005616	0.04359284	0.01154360	0.00078548	0.00015857	0.00249023	0.02630011	0.13204973	0.01681117	0.01189925	0.00026284	0.00021504	0.01447091	0.00234431
REV_RENT PRODUCTION	0.26113628	0.12804633	0.03239074	0.00037870	0.00000933	0.01355269	0.00385974	0.00030544	0.00006447	0.00081411	0.00887527	0.05927475	0.00929999	0.00367857	0.00008880	0.00006414	0.00034775	0.00008635
REV_RENT BULKTRAN	0.04636401	0.02273426	0.00575088	0.00006724	0.00000166	0.00240624	0.00068529	0.000005423	0.00001145	0.00014454	0.00157578	0.01052406	0.00165103	0.00065312	0.00001577	0.00001139	0.00006174	0.00001533
REV_RENT SUBTRAN	0.01778100	0.00844423	0.00216160	0.00002519	0.00000083	0.00094213	0.00026704	0.00002735	-	0.00002676	0.00080983	0.00496755	-	0.00025568	0.00000612	0.00000420	0.00001319	0.00000329
REV_RENT DISTPRI	0.17913091	0.11903225	0.02969775	0.00034971	-	0.01292292	0.00368554	-	-	0.00073704	0.00852492	-	-	0.00350706	0.00000603	0.00000603	0.00022118	0.00005516
REV_RENT DISTSEC	0.07310703	0.05458184	0.01225290	-	-	0.00431928	-	-	-	0.00019117	-	-	-	0.00120212	-	0.00001960	0.00043284	0.00010728
REV_RENT ENERGY	0.00026248	0.00009542	0.00003080	0.00000035	0.00000001	0.00001490	0.00000416	0.00000033	0.00000007	0.00000099	0.00001187	0.00008390	0.00000145	0.00000044	0.00000010	0.00000009	0.00000160	0.00000040
REV_RENT CUSTOMER	0.42221829	0.33603604	0.07975115	0.00022612	0.00000923	0.00098131	0.00019257	0.00002648	0.00001135	0.00001357	0.00006866	0.00001702	0.00003401	0.00000299	0.00002132	0.00007205	0.00086867	
REV_RENT TOTAL	1.00000000	0.66897036	0.16230582	0.00104731	0.00002105	0.03513948	0.00867734	0.00041383	0.00008734	0.00195420	0.01970984	0.07491893	0.01098058	0.00964161	0.00019780	0.00018107	0.00479895	0.00095448
REV PRODUCTION	0.27785605	0.12793262	0.03796132	0.00041484	0.00000668	0.01744721	0.00535366	0.00034644	0.00038293	0.00069667	0.01131526	0.06049501	0.00934191	0.00509403	0.00011829	0.00008948	0.00046257	0.00012413
REV BULKTRAN	0.08267393	0.02987476	0.01480638	0.00023949	0.00000762	0.00840969	0.00278278	0.00014391	(0.00067448)	0.00037224	0.00504380	0.01648901	0.00203759	0.00274633	0.00005078	0.00004587	0.00022646	0.00006640
REV SUBTRAN	0.03250578																	

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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	
REVVEEC_EXP_OM PRODUCTION	0.27943638	0.12095226	0.02371872	0.00839770	0.00107081	0.02615121	0.00048129	0.00138512	(0.01540666)	-	0.00232724	0.09953008	-	0.00981792	-	-	0.00101068	-
REVVEEC_EXP_OM BULKTRAN	0.04059650	0.00967896	0.00190901	0.00062091	(0.00006145)	0.00210335	0.00003909	0.00011239	0.01708747	-	0.00018786	0.00805097	-	0.00078623	-	-	0.00008171	-
REVVEEC_EXP_OM SUBTRAN	0.00961478	0.00359529	0.00071749	0.00023387	(0.00002514)	0.00082359	0.00001523	0.00000670	-	-	0.00007268	0.00379976	-	0.00030786	-	-	0.00001745	-
REVVEEC_EXP_OM DISTPRI	0.03032169	0.01909890	0.00372867	0.00114477	-	0.00421110	0.00007835	-	-	-	0.00038294	-	-	0.00157630	-	-	0.00010965	-
REVVEEC_EXP_OM DISTSEC	0.01117438	0.00786234	0.00136924	-	-	0.00126458	-	-	-	-	-	-	-	0.00048553	-	-	0.00019258	-
REVVEEC_EXP_OM ENERGY	0.54771812	0.16570120	0.04147277	0.01513751	0.00237027	0.05303348	0.00095133	0.00277140	(0.02745059)	-	0.00570266	0.25899002	-	0.01991331	-	-	0.00852475	-
REVVEEC_EXP_OM CUSTOMER	0.08113815	0.06028935	0.01099511	0.00240030	0.00117252	0.00046366	0.00001186	0.00019187	0.00180362	-	0.00001542	0.00018487	-	0.00021666	-	-	0.00339291	-
REVVEEC_EXP_OM TOTAL	1.00000000	0.38716930	0.08391101	0.02793506	0.00452702	0.08805098	0.00157715	0.00451748	(0.02396616)	-	0.00686880	0.37115570	-	0.03310382	-	-	0.01332983	-
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	(0.00000000)
TDOMX BULKTRAN	0.12220968	0.06041499	0.01528254	0.00017868	0.00000440	0.00639445	0.00182111	0.00014411	0.00003042	0.00038412	0.00418754	0.02796709	0.00438751	0.00173563	0.00004190	0.00003026	0.00016408	0.00004074
TDOMX SUBTRAN	0.04725197	0.02244005	0.00574432	0.00006894	0.00000219	0.00250365	0.00070966	0.00007269	-	0.00014022	0.00162060	0.01320098	-	0.00067948	0.00001626	0.00001116	0.00003505	0.00000873
TDOMX DISTPRI	0.23385479	0.15539620	0.03912280	0.00045655	-	0.01687083	0.00478927	-	-	0.00006221	0.01112925	-	-	0.00457846	0.00010970	0.00007877	0.00028875	0.000007201
TDOMX DISTSEC	0.08578089	0.06404416	0.01437707	-	-	0.00506807	-	-	-	0.00022432	-	-	-	0.00141052	-	0.00002300	0.00050788	0.00012588
TDOMX ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDOMX CUSTOMER	0.50990267	0.39812926	0.09772003	0.00085523	0.00011752	0.00165138	0.00071713	0.00033721	0.00014452	0.00002380	0.00044511	0.000087439	0.00021677	0.00055868	0.00000922	0.00003313	0.00628603	0.00178323
TDOMX TOTAL	1.00000000	0.70042466	0.17224686	0.00155740	0.00012412	0.03248839	0.00803716	0.00055402	0.00017494	0.00173466	0.01738251	0.04204247	0.00460428	0.00896277	0.00017707	0.00017632	0.00728179	0.00203059
TDPLANT PRODUCTION	0.00589261	0.00288940	0.00073091	0.00000855	0.00000021	0.00030582	0.00008710	0.00000689	0.00000145	0.00001837	0.00020027	0.00133755	0.00020984	0.00008301	0.00000200	0.00000145	0.00000785	0.00000195
TDPLANT BULKTRAN	0.31178124	0.15287972	0.03867263	0.00045214	0.00001114	0.01618111	0.00460830	0.00036468	0.00007698	0.00097200	0.01059655	0.07077053	0.01110256	0.00439199	0.00010602	0.00007657	0.00041520	0.00010310
TDPLANT SUBTRAN	0.11952034	0.05676043	0.01452983	0.00016932	0.00000555	0.00633281	0.00179502	0.00018387	-	0.00035467	0.00409918	0.03339090	-	0.00171869	0.00004112	0.00002822	0.00008866	0.00002208
TDPLANT DISTPRI	0.19439724	0.12917671	0.03252174	0.00037952	-	0.01404237	0.00398119	-	-	0.00079986	0.00925145	-	-	0.00380595	0.00009119	0.00006548	0.00024003	0.00005986
TDPLANT DISTSEC	0.06847071	0.05112035	0.01147584	-	-	0.00404536	-	-	-	0.00017905	-	-	-	0.00112588	-	0.00001836	0.00040539	0.00010048
TDPLANT ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TDPLANT CUSTOMER	0.29993786	0.22281057	0.05402455	0.00033596	0.00004385	0.00082367	0.00028202	0.00012581	0.00005392	0.00001173	0.00017426	0.00032624	0.00008088	0.00028086	0.00000368	0.00001692	0.01781949	0.00272345
TDPLANT TOTAL	1.00000000	0.61563718	0.15195549	0.00134548	0.00006075	0.04171304	0.01075363	0.00086125	0.00013235	0.00233568	0.02432172	0.05825282	0.01139327	0.01140638	0.00024402	0.00020700	0.01897661	0.00301092
TOTMEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMEXP DISTPRI	0.27180631	0.18061493	0.04547191	0.00053064	-	0.01960875	0.00556650	-	-	0.00111836	0.01293538	-	-	0.00532148	0.00012750	0.00009155	0.00033561	0.00008370
TOTMEXP DISTSEC	0.10236445	0.07642548	0.01715651	-	-	0.00604785	-	-	-	0.00026768	-	-	-	0.00168321	-	0.00002745	0.00006067	0.00015021
TOTMEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTMEXP CUSTOMER	0.62582924	0.50268738	0.11904200	0.00029775	0.00000501	0.00142772	0.00025453	0.00001438	0.00000616	0.00001966	0.00014589	0.00003728	0.00000924	0.00049739	0.00000413	0.00003124	0.00089542	0.00045406
TOTMEXP TOTAL	1.00000000	0.75972778	0.18167042	0.00082839	0.00000501	0.02708432	0.00582103	0.00001438	0.00000616	0.000140570	0.01308127	0.00003728	0.00000924	0.00750208	0.00013162	0.00015025	0.00183710	0.00068797
TOTOHLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES DISTPRI	0.24880464	0.16533035	0.04162384	0.00048574	-	0.01794935	0.00509543	-	-	0.00102372	0.01184072	-	-	0.00487115	0.00011671	0.00008381	0.00030721	0.00007661
TOTOHLINES DISTSEC	0.10562585	0.07886044	0.01770312	-	-	0.00624054	-	-	-	0.00027821	-	-	-	0.00173683	-	0.00002832	0.00062538	0.00002538
TOTOHLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOHLINES CUSTOMER	0.64556951	0.51976035	0.12292819	0.00027932	-	0.00145246	0.00023942	-	-	0.00001995	0.00013567	-	-	0.000050676	0.00000399	0.00003192	-	0.00021148
TOTOHLINES TOTAL	1.00000000	0.76395114	0.18225515	0.00076505	-	0.02564235	0.00533485	-	-	0.00131988	0.01197639	-	-	0.00711475	0.00012070	0.00014405	0.00093259	0.00044310
TOTOX234 PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234 CUSTOMER	1.00000000	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00002043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436
TOTOX234 TOTAL	1.00000000	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00002043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436
TOTOXEXP PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP DISTPRI	0.30970793	0.20580050	0.05181267	0.00060464	-	0.02234306	0.00634271	-	-	0.00127431	0.01473914	-	-	0.00606353	0.00014528	0.00010432	0.00038241	0.00009537
TOTOXEXP DISTSEC	0.10627919	0.07934823	0.01781263	-	-	0.00627914	-	-	-	0.00027792	-	-	-	0.00174758	-	0.00002850	0.00062925	0.00015596
TOTOXEXP ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOXEXP CUSTOMER	0.58401288	0.41735507	0.11438458	0.00304840	0.00051769	0.00353979	0.00254276	0.00148541	0.00063659	0.00005356	0.00161153	0.00385171	0.00095489	0.00115802	0.00003034	0.00006386	0.02596371	0.00681499
TOTOXEXP TOTAL	1.00000000	0.70250380	0.18400988	0.00365303	0.00051769	0.03216198	0.00888548	0.00148541	0.00063659	0.00160578	0.01635067	0.00385171	0.00095489	0.00896913	0.00017561	0.00019667	0.02697536	0.00706632
TOTUGLINES PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES DISTPRI	0.24643633	0.16375661	0.04122763	0.00048111	-	0.01777850	0.00504693	-	-	0.00101397	0.01172802	-	-	0.00482478	0.00011560	0.00008301	0.00030429	0.00007589
TOTUGLINES DISTSEC	0.33749496	0.25196687	0.05656322	-	-	0.01993913	-	-	-	0.00088252	-	-	-	0.00554936	-	0.00009049	0.00199814	0.00049523
TOTUGLINES ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTUGLINES CUSTOMER	0.41607871	0.33499292	0.07922896	0.00018002	-	0.00093613	0.00015431	-	-	0.00001286	0.000087							

KENTUCKY POWER COMPANY  
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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
TRANS_TOTAL PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL BULKTRAN	0.72280000	0.35441986	0.08965444	0.00104820	0.00002582	0.03751254	0.01068339	0.00084544	0.00017846	0.00225339	0.02456590	0.16406678	0.02573898	0.01018192	0.00024580	0.00017752	0.00096255	0.00023902
TRANS_TOTAL SUBTRAN	0.27720000	0.13164278	0.03369861	0.00039270	0.00001287	0.01468749	0.00416314	0.00042644	-	0.00082257	0.00950711	0.07744253	-	0.00398610	0.00009537	0.00006546	0.00020562	0.00005122
TRANS_TOTAL DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL TOTAL	1.00000000	0.48606264	0.12335305	0.00144089	0.00003870	0.05220004	0.01484652	0.00127188	0.00017846	0.00307596	0.03407302	0.24150930	0.02573898	0.01416803	0.00034117	0.00024298	0.00116816	0.00029024
WEATHER_FXNL PRODUCTION	0.38232067	0.14405291	0.14553836	0.00083620	-	0.06465239	0.01296427	-	-	-	-	-	-	0.01404024	0.00023629	-	-	-
WEATHER_FXNL BULKTRAN	(0.00065370)	(0.01881359)	0.00458471	0.00012928	-	0.00835020	0.00232940	-	-	-	-	-	-	0.00273345	0.00003284	-	-	-
WEATHER_FXNL SUBTRAN	0.00009679	(0.00679436)	0.00168709	0.00004703	-	0.00318787	0.00088332	-	-	-	-	-	-	0.00104340	0.00001243	-	-	-
WEATHER_FXNL DISTPRI	0.11510184	0.03276304	0.04604807	0.00032005	-	0.02469573	0.00529989	-	-	-	-	-	-	0.00588417	0.00009090	-	-	-
WEATHER_FXNL DISTSEC	0.03858422	0.01327188	0.01640943	-	-	0.00715817	-	-	-	-	-	-	-	0.00174473	-	-	-	-
WEATHER_FXNL ENERGY	0.29083701	0.09712104	0.11483483	0.00060673	-	0.05577650	0.01067944	-	-	-	-	-	-	0.01162150	0.00019698	-	-	-
WEATHER_FXNL CUSTOMER	0.17374317	0.07743033	0.09323961	0.00035574	-	0.00173887	0.00046677	-	-	-	-	-	-	0.00050720	0.00000464	-	-	-
WEATHER_FXNL TOTAL	1.00000000	0.33903126	0.42234211	0.00229503	-	0.16555973	0.03262309	-	-	-	-	-	-	0.03757470	0.00057408	-	-	-
WEATHER_FXNL_OM PRODUCTION	0.29643257	0.10591386	0.11938139	0.00068992	-	0.04917138	0.00995548	-	-	-	-	-	-	0.01114389	0.00017665	-	-	-
WEATHER_FXNL_OM BULKTRAN	0.02380522	0.00847554	0.00960847	0.00005101	-	0.00395488	0.00080859	-	-	-	-	-	-	0.00089241	0.00001431	-	-	-
WEATHER_FXNL_OM SUBTRAN	0.00899730	0.00314828	0.00361129	0.00001921	-	0.00154857	0.00031496	-	-	-	-	-	-	0.00034944	0.00000555	-	-	-
WEATHER_FXNL_OM DISTPRI	0.04693410	0.01671639	0.01876719	0.00009405	-	0.00791801	0.00162062	-	-	-	-	-	-	0.00178919	0.00002864	-	-	-
WEATHER_FXNL_OM DISTSEC	0.01670535	0.00689479	0.00689170	-	-	0.00237776	-	-	-	-	-	-	-	0.00055111	-	-	-	-
WEATHER_FXNL_OM ENERGY	0.49742867	0.14509902	0.20874135	0.00124364	-	0.09971733	0.01967814	-	-	-	-	-	-	0.02260273	0.00034645	-	-	-
WEATHER_FXNL_OM CUSTOMER	0.10969679	0.05279337	0.05534072	0.00019720	-	0.00087180	0.00024530	-	-	-	-	-	-	0.00024592	0.00000247	-	-	-
WEATHER_FXNL_OM TOTAL	1.00000000	0.33903126	0.42234211	0.00229503	-	0.16555973	0.03262309	-	-	-	-	-	-	0.03757470	0.00057408	-	-	-

KENTUCKY POWER COMPANY  
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TWELVE MONTHS ENDING  
MAY 31, 2025

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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
INPUTS FROM WORKPAPERS																			
CPG - 12 CP	Same as CPT	944,768	463,260	117,187	1,370	34	49,032	13,964	1,105	233	2,945	32,110	214,451	33,643	13,309	321	232	1,258	312
PROD_DEMAND	PRODUCTION	1,00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
PROD_DEMAND	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_DEMAND	TOTAL	1,00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
ENER		5,721,281,490	2,079,871,652	671,312,179	7,685,251	194,782	324,859,845	90,678,094	7,179,053	1,471,673	21,646,894	258,697,905	1,828,873,141	293,094,600	88,116,890	2,071,058	2,023,256	34,814,401	8,690,814
PROD_ENERGY	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	ENERGY	1,00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
PROD_ENERGY	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PROD_ENERGY	TOTAL	1,00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
CPT - 12 CP	Same as CPG	944,768	463,260	117,187	1,370	34	49,032	13,964	1,105	233	2,945	32,110	214,451	33,643	13,309	321	232	1,258	312
BULK_TRANS	PRODUCTION	1,00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
BULK_TRANS	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BULK_TRANS	TOTAL	1,00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
CPST - 12 CP		744,526	353,577	90,510	1,055	35	39,449	11,182	1,145	0	2,209	25,535	208,001	0	10,706	256	176	552	138
SUB_TRANS	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	SUBTRAN	1,00000000	0.47490181	0.12156786	0.00141666	0.00004644	0.05298518	0.01501853	0.00153839	-	0.00296741	0.03429695	0.27937419	-	0.01437988	0.00034405	0.00023613	0.00074176	0.00018478
SUB_TRANS	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUB_TRANS	TOTAL	1,00000000	0.47490181	0.12156786	0.00141666	0.00004644	0.05298518	0.01501853	0.00153839	-	0.00296741	0.03429695	0.27937419	-	0.01437988	0.00034405	0.00023613	0.00074176	0.00018478
CPD - 12 CP		686,086	455,903	114,779	1,339	0	49,496	14,051	0	0	2,823	32,651	0	0	13,432	322	231	847	211
DIST_CPD	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	SUBTRAN	1,00000000	0.66449865	0.16729526	0.00195228	-	0.07214235	0.02047965	-	-	0.00411454	0.04759045	-	-	0.01957822	0.00046908	0.00033684	0.00123474	0.00030793
DIST_CPD	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_CPD	TOTAL	1,00000000	0.66449865	0.16729526	0.00195228	-	0.07214235	0.02047965	-	-	0.00411454	0.04759045	-	-	0.01957822	0.00046908	0.00033684	0.00123474	0.00030793
SECDM	( NCP + SNCP ) / 2	1,372,476	1,024,693	230,030	0	0	81,088	0	0	0	3,589	0	0	0	22,568	0	368	8,126	2,014
DISTSEC	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	DISTSEC	1,00000000	0.74660176	0.16760220	-	-	0.05908154	-	-	-	0.00261498	-	-	-	0.01644327	-	0.00026813	0.00592069	0.00146742
DISTSEC	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTSEC	TOTAL	1,00000000	0.74660176	0.16760220	-	-	0.05908154	-	-	-	0.00261498	-	-	-	0.01644327	-	0.00026813	0.00592069	0.00146742
TOTCUST		207,831	130,257	30,807	70	3	364	60	7	2	5	34	17	3	127	1	8	46,013	53
CUST_TOTAL	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_TOTAL	TOTAL	1,00000000	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00028870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501
		1,00000000	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00028870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501
PRICUST	TOTCust excl Sub. & Tran.	207,799	130,257	30,807	70	0	364	60	0	0	5	34	0	0	127	1	8	46,013	53
DIST_PCUST	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_PCUST	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		



KENTUCKY POWER COMPANY  
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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		35,798,155	21,991,911	9,222,723	744,564	132,803	670,332	620,203	381,053	163,305	10,474	395,221	988,082	244,959	214,122	7,247	11,156	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	0.61433085	0.25763124	0.02079895	0.00370977	0.01872532	0.01732500	0.01064449	0.00456183	0.00029258	0.01104026	0.02760148	0.00684278	0.00598137	0.00020244	0.00031164	-	-
DIST_METERS	TOTAL	1,00000000	0.61433085	0.25763124	0.02079895	0.00370977	0.01872532	0.01732500	0.01064449	0.00456183	0.00029258	0.01104026	0.02760148	0.00684278	0.00598137	0.00020244	0.00031164	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_SL	TOTAL	1,00000000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIR902	Weighted TOTCUST	355,993	260,514	92,421	245	11	1,638	300	35	10	30	204	102	18	445	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	0.73179529	0.25961466	0.00068822	0.00003090	0.00460121	0.00084271	0.00009832	0.00002809	0.00008427	0.00057304	0.00028652	0.00005056	0.00125002	0.00001124	0.00004494	-	-
CUST_902	TOTAL	1,00000000	0.73179529	0.25961466	0.00068822	0.00003090	0.00460121	0.00084271	0.00009832	0.00002809	0.00008427	0.00057304	0.00028652	0.00005056	0.00125002	0.00001124	0.00004494	-	-
DIR903	Calculated Weighted Average	2,386,906	2,011,442	366,493	832	36	4,331	714	83	24	59	405	202	36	1,511	12	95	0	631
CUST_903	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_903	CUSTOMER	1,00000000	0.84269846	0.15354312	0.00034857	0.00001508	0.00181448	0.00022913	0.00003477	0.00001005	0.00002472	0.00016968	0.00008463	0.00001508	0.00063304	0.00000503	0.00003980	-	0.00026436
CUST_903	TOTAL	1,00000000	0.84269846	0.15354312	0.00034857	0.00001508	0.00181448	0.00022913	0.00003477	0.00001005	0.00002472	0.00016968	0.00008463	0.00001508	0.00063304	0.00000503	0.00003980	-	0.00026436
CUST451	Spread by class; alloc. to functions below: MISC_SERV_REV	166,771	147,796	15,228	87	5	149	116	0	0	0	0	34	0	0	0	0	3,357	0
CUST_451	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_451	CUSTOMER	1,00000000	0.88622070	0.09130891	0.00052047	0.00002818	0.00089344	0.00069616	-	-	-	-	0.00020387	-	-	-	-	0.02012826	-
CUST_451	TOTAL	1,00000000	0.88622070	0.09130891	0.00052047	0.00002818	0.00089344	0.00069616	-	-	-	-	0.00020387	-	-	-	-	0.02012826	-
CUSTDEP	Spread by class; alloc. to functions below: CUST_DEP_FXNL	37,698,806	25,026,861	5,406,256	316,154	64,116	1,309,458	1,412,193	273,653	16,275	212,410	1,571,997	1,565,497	361,852	28,410	0	0	133,675	0
CUST_DEP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_DEP	CUSTOMER	1,00000000	0.66386348	0.14340656	0.00838631	0.00170076	0.03473474	0.03745989	0.00725892	0.00043171	0.00563440	0.04169885	0.04152643	0.00959850	0.00075360	-	-	0.00354587	-
CUST_DEP	TOTAL	1,00000000	0.66386348	0.14340656	0.00838631	0.00170076	0.03473474	0.03745989	0.00725892	0.00043171	0.00563440	0.04169885	0.04152643	0.00959850	0.00075360	-	-	0.00354587	-
FORF DISCOUNTS	Spread by class; alloc. to functions below: FORF_DISC_FXNL	1,035,102	109	515,222	5,911	1,231	75,241	137,613	9,024	0	-17,967	135,813	168,119	0	0	0	0	4,786	0
FORF_DISC	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FORF_DISC	CUSTOMER	1,00000000	0.00010530	0.49774998	0.00571055	0.00118925	0.07268945	0.13294632	0.00871798	-	(0.01735771)	0.13120736	0.16241781	-	-	-	-	0.00462370	-
FORF_DISC	TOTAL	1,00000000	0.00010530	0.49774998	0.00571055	0.00118925	0.07268945	0.13294632	0.00871798	-	(0.01735771)	0.13120736	0.16241781	-	-	-	-	0.00462370	-
YEAR END CUST ADJ	Spread by class; alloc. to functions below: REVVEC_FXNL	(2,908,256)	(1,125,987)	(244,035)	(81,242)	(13,166)	(256,075)	(4,587)	(13,138)	69,700	-	(25,269)	(1,079,416)	-	(96,274)	-	-	(38,767)	-
REVVEC	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVVEC	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVVEC	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVVEC	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVVEC	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVVEC	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REVVEC	CUSTOMER	1,00000000	0.38716930	0.08391101	0.02793506	0.00452702	0.08805098	0.00157715	0.00451748	(0.02396616)	-	0.00868880	0.37115570	-	0.03310382	-	-	0.01332983	-
REVVEC	TOTAL	1,00000000	0.38716930	0.08391101	0.02793506	0.00452702	0.08805098	0.00157715	0.00451748	(0.02396616)	-	0.00868880	0.37115570	-	0.03310382	-	-	0.01332983	-

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
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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	5,721,281,490	2,079,871,652	671,312,179	7,685,251	194,782	324,859,845	90,678,094	7,179,053	1,471,673	21,646,894	258,697,905	1,828,873,141	293,094,600	88,116,890	2,071,058	2,023,256	34,814,401	8,690,814
FUELR	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELR	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELR	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELR	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELR	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELR	ENERGY		1,00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
FUELR	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUELR	TOTAL		1,00000000	0.36353248	0.11733598	0.00134327	0.00003405	0.05678096	0.01584926	0.00125480	0.00025723	0.00378357	0.04521678	0.31966145	0.05122884	0.01540160	0.00036199	0.00035364	0.00608507	0.00151903
WEATHER		Spread by class; alloc. to functions below:	(1,012,932)	(343,415)	(427,804)	(2,325)	-	(167,701)	(33,045)	-	-	-	-	-	-	(38,061)	(581)	-	-	-
WEATHER	PRODUCTION	WEATHER_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER	ENERGY		1,00000000	0.33903126	0.42234211	0.00229503	-	0.16555973	0.03262309	-	-	-	-	-	-	0.03757470	0.00057408	-	-	-
WEATHER	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WEATHER	TOTAL		1,00000000	0.33903126	0.42234211	0.00229503	-	0.16555973	0.03262309	-	-	-	-	-	-	0.03757470	0.00057408	-	-	-
PRO FORMA ADJ		Spread by class; alloc. to functions below:	(867,856)	-	-	-	-	-	(393,732)	-	-	-	-	-	(474,124)	-	-	-	-	-
CUST_SPEC	PRODUCTION	CUST_SPEC_FXNL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	ENERGY		1,00000000	-	-	-	-	-	0.45368337	-	-	-	-	-	0.54631663	-	-	-	-	-
CUST_SPEC	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CUST_SPEC	TOTAL		1,00000000	-	-	-	-	-	0.45368337	-	-	-	-	-	0.54631663	-	-	-	-	-
INTERNALLY DERIVED																				
Bulk Transmission Plant			\$685,857,713																	
Subtransmission Plant			\$263,076,317																	
Total Transmission Plant			\$948,934,030																	
BULK_TRANS	BULKTRAN	72.28%	1,00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
SUB_TRANS	SUBTRAN	27.72%	1,00000000	0.47490181	0.12156786	0.00141666	0.00004644	0.05298518	0.01501853	0.00153839	-	0.00296741	0.03429695	0.27937419	-	0.01437988	0.00034405	0.00023613	0.00074176	0.00018478
TRANS_TOTAL			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	TRANS_TOTAL		0.72280000	0.35	0.08965444	0.00104820	0.00002582	0.03751254	0.01068339	0.00084544	0.00017846	0.00225339	0.02456590	0.16406678	0.02573898	0.01018192	0.00024580	0.00017752	0.00096255	0.00023902
TRANS_TOTAL	SUBTRAN		0.27720000	0.13	0.03369861	0.00039270	0.00001287	0.01468749	0.00416314	0.00004264	-	0.00082257	0.00950711	0.07744253	-	0.00398610	0.00009537	0.00006546	0.00020562	0.00005122
TRANS_TOTAL	DISTPRI		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	DISTSEC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANS_TOTAL	TOTAL		1,00000000	0.48606264	0.12335305	0.00144089	0.00003870	0.05220004	0.01484652	0.00127188	0.00017846	0.00307596	0.03407302	0.24150930	0.02573898	0.01416803	0.00034117	0.00024298	0.00116816	0.00029024
DIST_CPD	DISTPRI	57.25%	1,00000000	0.66449865	0.16729526	0.00195228	-	0.07214235	0.02047965	-	-	0.00411454	0.04759045	-	-	0.01957822	0.00046908	0.00033684	0.00123474	0.00030793
DISTSEC	DISTSEC	42.75%	1,00000000	0.74660176	0.16760220	-	-	0.05908154	-	-	-	0.00281498	-	-	-	0.01644327	-	0.00026813	0.00592069	0.00146742
DIST_PCUST Excl OL	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	DISTPRI		0.57249889	0.38	0.09577635	0.00111768	-	0.04130142	0.01172458	-	-	0.00235557	0.02724548	-	-	0.01120851	0.00026855	0.00019284	0.00070689	0.00017629
DIST_POLES	DISTSEC		0.42750111	0.32	0.07165013	-	-	0.02525743	-	-	-	0.00111791	-	-	-	0.00702952	-	0.00011463	0.00225310	0.00062732
DIST_POLES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_POLES	TOTAL		1,00000000	0.69959782	0.16742648	0.00111768	-	0.06655884	0.01172458	-	-	0.00347348	0.02724548	-	-	0.01623803	0.00026855	0.00030746	0.00323799	0.00080361
DIST_CPD	DISTPRI	24.88%	1,00000000	0.66449865	0.16729526	0.00195228	-	0.07214235	0.02047965	-	-	0.00411454	0.04759045	-	-	0.01957822	0.00046908	0.00033684	0.00123474	0.00030793
DISTSEC	DISTSEC	10.56%	1,00000000	0.74660176	0.16760220	0.00195228	-	0.05908154	-	-	-	0.00281498	-	-	-	0.01644327	-	0.00026813	0.00592069	0.00146742
DIST_PCUST Excl OL	CUSTOMER	64.56%	1,00000000	0.80511911	0.19041821	0.00043267	-	0.00224989	0.00037086	-	-	0.00003091	0.00021015	-	-	0.00078499	0.00000618	0.00004945	-	0.00032759
DIST_OH LINES	PRODUCTION		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OH LINES	BULKTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OH LINES	SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OH LINES	DISTPRI		0.24880464	0.16533035	0.04162384	0.00048574	-	0.01794935	0.00509543	-	-	0.00102372	0.01184072	-	-	0.00487115	0.00011671	0.00008381	0.00030721	0.00007661
DIST_OH LINES	DISTSEC		0.10562585	0.07886044	0.01770312	-	-	0.00624054	-	-	-	0.00027621	-	-	-	0.00173683	-	0.00002832	0.00062538	0.00015500
DIST_OH LINES	ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OH LINES	CUSTOMER		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DIST_OH LINES	TOTAL		1,00000000	0.64556951	0.12292819	0.00027932	-	0.00145246	0.00023942	-	-	0.00001195	0.00013567	-	-	0.00050676	0.00000399	0.00003192	-	0.00021148
DIST_CPD	DISTPRI	24.64%	1,00000000	0.66449865	0.16729526	0.00195228	-	0.07214235	0.02047965	-	-	0.00411454	0.04759045	-	-	0.01957822	0.00046908	0.00033684	0.00123474	0.00030793
DISTSEC	DISTSEC	33																		

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

Exhibit No.: NMC-1  
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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
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).																			
TRAN_LSE	PRODUCTION	1.00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
TRAN_LSE	BULKTRAN																		
TRAN_LSE	SUBTRAN																		
TRAN_LSE	DISTPRI																		
TRAN_LSE	DISTSEC																		
TRAN_LSE	ENERGY																		
TRAN_LSE	CUSTOMER																		
TRAN_LSE	TOTAL	1.00000000	0.49034292	0.12403769	0.00145019	0.00003573	0.05189893	0.01478056	0.00116967	0.00024690	0.00311758	0.03398714	0.22698779	0.03561010	0.01408678	0.00034006	0.00024560	0.00133169	0.00033068
Production EPIS	PRODUCTION	606,309,553	297,299,595	75,205,237	879,264	21,661	31,466,815	8,961,594	709,190	149,695	1,890,221	20,606,726	137,624,967	21,590,741	8,540,949	206,182	148,910	807,418	200,496
	BULKTRAN	10,679,002	5,236,373	1,324,599	15,487	382	554,229	157,842	12,491	2,637	33,293	362,949	2,424,003	380,280	150,433	3,632	2,623	14,221	3,531
	SUBTRAN	4,095,489	1,944,955	497,880	5,802	190	217,000	61,508	6,300	-	12,153	140,463	1,144,174	-	58,893	1,409	967	3,038	757
	DISTPRI	4,882,612	3,244,489	816,838	9,532	-	352,243	99,994	-	-	20,000	232,366	-	-	95,593	2,290	1,645	6,029	1,504
	DISTSEC	2,040,505	1,530,164	345,502	-	-	121,088	-	-	-	5,359	-	-	-	33,701	-	550	12,134	3,007
	ENERGY	608,430	221,547	71,508	819	21	34,604	9,659	765	157	2,306	27,556	194,811	31,220	9,386	221	216	3,708	926
	CUSTOMER	12,774,797	10,267,685	2,425,471	6,607	208	29,546	5,641	593	253	408	3,265	1,538	379	10,272	89	643	15,244	6,955
	TOTAL	641,400,387	319,744,808	80,685,035	917,510	22,461	32,775,525	9,296,238	729,330	152,742	1,963,830	21,373,325	141,389,393	22,002,621	8,899,226	213,822	155,552	861,793	217,177
RB_GUP_EPIS_P	PRODUCTION	0.94529028	0.46351639	0.11725162	0.00137085	0.00003377	0.04905955	0.01397192	0.00110567	0.00023339	0.00294702	0.03212771	0.21456935	0.03366188	0.01331610	0.00032146	0.00023216	0.00125884	0.00031259
RB_GUP_EPIS_P	BULKTRAN	0.01664951	0.00816397	0.00205617	0.00002414	0.00000059	0.00086409	0.00024609	0.00001947	0.00000411	0.00005191	0.00005687	0.00377924	0.000059289	0.00023454	0.00000566	0.00000409	0.00002217	0.00000551
RB_GUP_EPIS_P	SUBTRAN	0.00638523	0.00303236	0.00077624	0.00000905	0.00000030	0.00033832	0.00009590	0.00000982	-	0.00001895	0.00021899	0.00178387	-	0.00009182	0.00000220	0.00000151	0.00000474	0.00000118
RB_GUP_EPIS_P	DISTPRI	0.00761242	0.00505645	0.00127352	0.00001498	-	0.00054918	0.00015590	-	-	0.00003112	0.00036228	-	-	0.00014904	0.00000357	0.00000256	0.00000940	0.00000234
RB_GUP_EPIS_P	DISTSEC	0.00319536	0.00238566	0.00053555	-	-	0.00018879	-	-	-	0.00000836	-	-	-	0.00005254	-	0.00000086	0.00001892	0.00000469
RB_GUP_EPIS_P	ENERGY	0.00095015	0.00034541	0.00011149	0.00000128	0.00000003	0.00005395	0.00000119	0.00000039	0.00000024	0.00000359	0.00004296	0.00030373	0.00004868	0.00001463	0.00000034	0.00000078	0.00000144	0.00000144
RB_GUP_EPIS_P	CUSTOMER	0.01991704	0.01602623	0.00378152	0.00001030	0.00000032	0.00004606	0.000003679	0.00000083	0.00000039	0.00000084	0.00000509	0.00000240	0.00000059	0.00001601	0.00000014	0.00000100	0.00002377	0.00001084
RB_GUP_EPIS_P	TOTAL	1.00000000	0.49851047	0.12579511	0.00143048	0.00003502	0.05102995	0.01449366	0.00113709	0.00023814	0.00306178	0.03332291	0.22043858	0.03430403	0.01387468	0.00033337	0.00024252	0.00134361	0.00033860
Transmission EPIS	PRODUCTION	12,793,807	6,273,353	1,586,914	18,553	457	663,985	189,100	14,964	3,159	39,886	434,825	2,904,038	455,589	180,224	4,351	3,142	17,037	4,231
	BULKTRAN	676,927,692	331,926,699	83,964,548	961,673	24,184	35,131,820	10,005,370	791,780	167,131	2,110,379	23,066,835	163,654,323	24,105,460	9,535,732	230,196	166,254	901,460	223,849
	SUBTRAN	259,498,070	123,236,102	31,546,624	367,620	12,052	13,749,551	3,897,279	399,210	-	770,037	8,899,991	72,497,063	-	3,731,550	89,280	61,276	192,485	47,950
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	949,219,569	461,436,154	117,098,086	1,367,847	36,693	49,545,357	14,091,749	1,205,954	170,290	2,920,302	32,341,651	229,055,424	24,561,049	13,447,505	323,827	230,671	1,110,982	276,029
RB_GUP_EPIS_T	PRODUCTION	0.01347824	0.00660896	0.00167181	0.00001955	0.00000048	0.00069951	0.00019922	0.00001577	0.00000333	0.00004202	0.00045809	0.00305940	0.00047996	0.00018986	0.00003458	0.00000331	0.00001795	0.00000446
RB_GUP_EPIS_T	BULKTRAN	0.13141432	0.34968379	0.08845640	0.00103419	0.00002548	0.03701127	0.01054063	0.00003414	0.000017607	0.00222328	0.02423763	0.16187437	0.02539503	0.01004586	0.00024251	0.00017515	0.00004969	0.00023582
RB_GUP_EPIS_T	SUBTRAN	0.27338045	0.12962887	0.03323427	0.000038729	0.000001270	0.01448511	0.00410577	0.00042057	-	0.00081123	0.00937611	0.07637544	-	0.00393118	0.00009406	0.00006455	0.00002078	0.00005052
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	0.48612162	0.12336249	0.00144102	0.00003966	0.05219589	0.01484562	0.00127047	0.00017940	0.00307653	0.03407183	0.24130921	0.02587499	0.01416691	0.00034115	0.00024301	0.00117042	0.00029080
Distribution EPIS	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	422,067,976	280,463,602	70,609,973	823,993	-	30,448,976	8,643,806	-	-	1,736,617	20,086,405	-	-	8,263,339	197,983	142,169	521,146	129,968
	DISTSEC	148,661,023	110,990,582	24,915,915	-	-	8,783,123	-	-	-	388,746	-	-	-	2,444,474	-	39,860	880,175	218,148
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	651,213,806	483,757,933	117,296,074	729,413	95,201	1,788,327	612,312	273,161	117,066	25,473	378,355	708,314	175,601	609,786	7,990	36,740	38,689,007	5,913,053
	TOTAL	1,221,942,806	875,212,117	212,821,961	1,553,406	95,201	41,020,426	9,256,118	273,161	117,066	2,150,835	20,464,760	708,314	175,601	11,317,599	205,973	218,769	40,090,328	6,261,169
RB_GUP_EPIS_D	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	DISTPRI	0.34540731	0.22952269	0.05778501	0.00067433	-	0.02491850	0.00707382	-	-	0.00142119	0.01643809	-	-	0.00676246	0.00016202	0.00011635	0.00042649	0.00010636
RB_GUP_EPIS_D	DISTSEC	0.12165956	0.09083124	0.02039041	-	-	0.00718783	-	-	-	0.00031814	-	-	-	0.00200048	-	0.00003262	0.00072031	0.00017853
RB_GUP_EPIS_D	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RB_GUP_EPIS_D	CUSTOMER	0.53293313	0.39589245	0.09599146	0.00059693	0.00007791	0.00146351	0.00050110	0.00022355	0.00009580	0.00002085	0.00003063	0.00057966	0.00014371	0.00049903	0.00000654	0.00000307	0.03166188	0.00483906
RB_GUP_EPIS_D	TOTAL	1.00000000	0.71624638	0.17416688	0.00127126	0.00007791	0.03356984	0.00757492	0.00022355	0.00009580	0.00176018	0.01674772	0.00057966	0.00014371	0.00926197	0.00016856	0.00017903	0.03280868	0.00512395

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

Exhibit No.: NMC-1  
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Witness: N. Coon

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	40,433,845	19,826,450	5,015,321	58,637	1,445	2,098,473	597,635	47,294	9,983	126,056	1,374,231	9,177,989	1,439,853	569,583	13,750	9,931	53,845	13,371
	BULKTRAN	10,870,665	5,334,767	1,349,489	15,778	389	564,643	160,808	12,726	2,686	33,918	369,769	2,469,551	387,426	153,259	3,700	2,672	14,488	3,598
	SUBTRAN	4,172,445	1,981,502	507,235	5,911	194	221,078	62,664	6,419	-	12,381	143,102	1,165,673	-	50,999	1,436	985	3,095	771
	DISTPRI	19,339,762	12,851,246	3,235,450	37,757	-	1,395,216	396,072	-	-	79,574	920,388	-	-	378,638	9,072	6,514	23,880	5,955
	DISTSEC	7,094,068	5,296,444	1,186,981	-	-	419,129	-	-	-	19,551	-	-	-	116,650	1,902	-	10,410	-
	ENERGY	29,164,538	10,602,257	3,422,050	39,176	993	1,655,990	462,236	36,596	7,502	1,318,726	9,322,779	-	1,494,065	448,191	10,557	10,314	177,468	44,302
	CUSTOMER	55,251,306	43,644,098	10,181,910	-	-	93,300	162,790	9,930	-	2,346	39,393	73,601	18,156	55,027	834	3,264	729,486	150,681
	TOTAL	166,335,629	99,536,762	24,900,436	232,844	12,950	6,517,319	1,743,121	131,433	32,270	1,465,809	22,029,594	3,339,501	1,782,337	39,348	35,582	1,044,254	229,088	-
	PRODUCTION	0.24308589	0.11919545	0.03015181	0.00035252	0.00008688	0.01261590	0.00359955	0.00028433	0.00006002	0.00075784	0.00826179	0.05517753	0.00856531	0.00342430	0.00008266	0.00005970	0.00032372	0.00008038
	RB_GUP_EPIS_G	0.06540791	0.03207230	0.00811305	0.00009485	0.00000234	0.00339460	0.00096677	0.00007651	0.00001615	0.00020391	0.00222303	0.01484680	0.00232918	0.00092139	0.00002224	0.00001606	0.00008710	0.00002163
	RB_GUP_EPIS_G	0.02508449	0.01191287	0.00304947	0.00033554	0.00000117	0.00132911	0.00037673	0.00003859	-	0.00007444	0.00086032	0.00070096	-	0.00036071	0.00000863	0.00000592	0.00001861	0.00004464
	RB_GUP_EPIS_G	0.11620951	0.07726093	0.01945134	0.00022899	-	0.00838796	0.00238116	-	-	0.00047840	0.00553332	-	-	0.00227635	0.00004544	0.00003916	0.00014356	0.00003580
	RB_GUP_EPIS_G	0.04264912	0.03184191	0.00714809	-	-	0.00251978	-	-	-	0.00011153	-	-	-	0.00070129	-	0.00001144	0.00025251	0.00006258
	RB_GUP_EPIS_G	0.17533549	0.06374014	0.02057316	0.00023552	0.00000597	0.00095572	0.00277894	0.00022001	0.00004510	0.00066339	0.00792811	0.05804800	0.00898223	0.00027045	0.00006347	0.00006201	0.00106693	0.00026634
	RB_GUP_EPIS_G	0.33216759	0.26238574	0.06121304	0.00045442	0.00005970	0.00097868	0.00038030	0.00017073	0.00001410	0.00027274	0.00044249	0.00010915	0.00033082	0.00000501	0.00001962	0.00438562	0.00009589	-
	RB_GUP_EPIS_G	0.59840915	0.14696995	0.04696995	0.00139985	0.00007786	0.03918174	0.01047954	0.00079017	0.00019401	0.00230361	0.02504339	0.13352277	0.02007688	0.01071530	0.00023656	0.00021392	0.00827805	0.00137726
	TOTAL	1.00000000	0.59840915	0.14696995	0.00139985	0.00007786	0.03918174	0.01047954	0.00079017	0.00019401	0.00230361	0.02504339	0.13352277	0.02007688	0.01071530	0.00023656	0.00021392	0.00827805	0.00137726
Production Land	Allocate on PROD_DEMAND	2,130,879	Source: JCOS, Sch 4, KY PSC Juris	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	PRODUCTION	604,178,673	296,254,733	74,940,928	876,173	21,585	31,256,224	8,930,099	706,688	149,169	1,883,578	20,534,304	137,141,184	21,514,860	8,510,932	205,457	148,386	804,581	199,792
	BULKTRAN	10,679,002	5,236,373	1,324,599	15,407	382	554,229	157,842	12,491	2,637	33,293	362,940	2,404,003	380,280	150,433	3,623	2,623	14,321	-
	SUBTRAN	4,095,489	1,944,495	497,880	5,832	190	217,000	61,508	6,300	-	12,153	140,463	1,144,174	-	58,893	1,409	967	3,028	757
	DISTPRI	4,882,612	3,244,489	816,838	9,502	-	352,243	99,994	-	-	20,090	232,366	-	-	95,593	2,290	1,645	6,029	1,504
	DISTSEC	2,040,505	1,530,164	343,502	-	-	121,088	-	-	-	5,359	-	-	-	33,701	-	650	12,134	3,007
	ENERGY	609,430	221,547	71,508	819	21	34,604	6,659	765	157	2,306	27,556	194,811	31,220	9,386	221	216	3,708	926
	CUSTOMER	12,774,797	10,267,685	2,425,471	6,807	208	29,546	5,641	593	253	408	3,265	1,538	379	10,272	89	643	15,244	6,955
	ENERGY	639,269,508	319,699,946	80,420,725	914,420	22,385	32,654,934	9,264,743	726,837	152,216	1,957,187	21,300,903	140,805,710	21,628,740	8,869,209	215,068	155,029	858,955	216,472
	TOTAL	0.94510792	0.46342697	0.11722900	0.00137059	0.00003377	0.04905009	0.01396922	0.00110546	0.00023334	0.00294645	0.03212151	0.21452796	0.03365538	0.01313533	0.00032139	0.00023212	0.00125859	0.00031253
	RB_GUP_Land_P	0.01670501	0.00819118	0.00207205	0.00000243	0.00000060	0.00086697	0.00024691	0.00001954	0.00000412	0.00005208	0.00005676	0.00039183	0.00059487	0.00023532	0.00000568	0.00000410	0.00002225	0.00001552
	RB_GUP_Land_P	0.00640651	0.00304247	0.00077883	0.00000908	0.00000030	0.00033945	0.00009622	0.00000086	-	0.00001901	0.00021972	0.01778981	-	0.00000212	0.00000020	0.00000151	0.00000475	0.00000118
	RB_GUP_Land_P	0.00076390	0.00507531	0.00127777	0.00001491	-	0.00055101	0.00015642	-	-	0.00003143	0.00035349	-	-	0.00014653	0.00000358	0.00000257	0.00000043	0.00000235
	RB_GUP_Land_P	0.00230901	0.00203961	0.00053733	-	-	0.00018942	-	-	-	0.00000838	-	-	-	0.00005272	-	0.00000086	0.00000188	0.00000470
	RB_GUP_Land_P	0.00095332	0.00034656	0.00011186	0.00000128	0.00000003	0.00005413	0.00000151	0.00000120	0.00000025	0.00000361	0.00004311	0.00030474	0.00004884	0.00001468	0.00000035	0.00000034	0.00000145	0.00000145
	RB_GUP_Land_P	0.01988343	0.01609159	0.00379413	0.00001034	0.00000032	0.00004622	0.00000082	0.00000093	0.00000040	0.00000511	0.00000241	0.00000059	0.00000167	0.00000014	0.00000011	0.00000235	0.00000578	0.00000578
	RB_GUP_Land_P	0.00000000	0.49853769	0.12580097	0.00143041	0.00000302	0.01049278	0.00035052	0.00113698	0.00023811	0.00036100	0.03332069	0.22041675	0.03429968	0.01387997	0.00033535	0.00024251	0.00130365	0.00003862
TOTAL	1.00000000	0.49853769	0.12580097	0.00143041	0.00000302	0.01049278	0.00035052	0.00113698	0.00023811	0.00036100	0.03332069	0.22041675	0.03429968	0.01387997	0.00033535	0.00024251	0.00130365	0.00003862	
Transmission Land	Allocate on BULK_TRANS	40,915,361	Source: JCOS, Sch 4, KY PSC Juris	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	PRODUCTION	12,793,807	6,273,353	1,586,914	18,553	457	663,985	189,100	14,964	3,159	39,886	434,825	2,904,038	455,589	180,224	4,351	3,142	17,037	4,231
	BULKTRAN	636,012,331	311,864,142	78,890,501	922,338	22,722	33,008,357	9,400,618	743,922	157,029	1,982,822	21,616,239	144,367,035	22,648,460	8,959,366	216,282	156,205	846,973	210,319
	SUBTRAN	259,498,070	123,236,102	31,546,624	367,620	12,052	13,749,551	3,897,279	399,210	-	770,037	8,999,991	72,497,063	-	3,731,550	89,280	61,276	192,485	47,950
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	908,304,208	441,373,597	112,023,039	1,308,512	35,231	47,421,893	13,486,997	1,158,097	160,188	2,792,744	30,951,055	219,768,136	23,104,049	12,871,140	309,913	220,622	1,056,496	262,499
	PRODUCTION	0.01408538	0.00690666	0.00174712	0.00000243	0.00000050	0.00073102	0.00020819	0.00016488	0.00000348	0.00004391	0.00047872	0.00050158	0.00019842	0.00000479	0.00000346	0.00001876	0.00000466	0.00000466
	RB_GUP_Land_T	0.70021951	0.34334768	0.0885361	0.00101545	0.00002502	0.03634064	0.01034964	0.00081902	0.00017288	0.00218299	0.02379846	0.15894128	0.02493488	0.00986384	0.00023812	0.00017197	0.00093248	0.00023155
	RB_GUP_Land_T	0.28569511	0.13567712	0.03471334	0.00004473	0.00001327	0.01513761	0.00429072	0.00043951	-	0.00084777	0.00979847	0.07981584	-	0.00010826	0.00003829	0.00006746	0.00021192	0.00005279
	RB_GUP_Land_T	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

Exhibit No.: NMC-1  
Page 24 of 30  
Witness: N. Coon

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	9,867,193	4,838,308	1,223,904	14,309	353	512,097	145,843	11,541	2,436	30,762	335,358	2,239,732	351,372	138,097	3,355	2,423	13,140	3,263
	BULKTRAN	68,578,338	33,627,393	8,506,423	99,453	2,450	3,559,194	1,013,641	80,215	16,932	213,802	2,330,815	15,566,673	2,442,117	966,062	23,321	16,843	91,327	22,678
	SUBTRAN	26,289,709	12,485,031	3,195,984	37,244	1,221	1,392,965	394,833	40,444	-	78,012	901,657	7,344,666	-	378,043	9,045	6,208	19,501	4,858
	DISTPRI	18,471,954	12,274,588	3,090,270	36,062	-	1,332,810	378,299	-	-	76,004	879,089	-	-	361,648	8,665	6,222	22,808	5,688
	DISTSEC	6,513,172	4,862,746	1,091,622	-	-	384,808	-	-	-	17,032	-	-	-	107,098	-	1,746	38,562	9,558
	ENERGY	266,685	96,949	31,292	-	-	15,143	4,227	335	69	1,009	12,059	85,249	13,662	4,107	97	94	1,623	405
	CUSTOMER	28,796,810	21,425,460	5,190,583	32,272	4,204	79,103	27,094	12,061	5,168	1,127	16,739	31,274	7,752	26,971	354	1,625	1,678,134	256,888
	TOTAL	158,784,862	89,610,475	22,330,077	219,699	8,236	7,275,920	1,963,337	144,596	24,605	417,747	4,475,716	25,267,594	2,814,903	1,982,926	44,837	35,162	1,665,095	303,338
	PRODUCTION	0.06241490	0.03047084	0.00770794	0.00009012	0.00000222	0.00325210	0.00091849	0.00007269	0.00001534	0.00019373	0.00211203	0.01410545	0.00221288	0.00087538	0.00002113	0.00001526	0.00008275	0.00002055
	BULKTRAN	0.431910099	0.21177959	0.05357200	0.00062634	0.00001543	0.02241520	0.00638374	0.00005018	0.00010663	0.00134649	0.01467908	0.09803625	0.01538004	0.00608409	0.00014687	0.00057516	0.00014282	0.00039100
SUBTRAN	0.16556811	0.07862859	0.02012776	0.00024553	0.00000769	0.00877266	0.00248669	0.00025471	-	0.00049131	0.00567848	0.04625546	-	0.00227760	0.00005696	0.00003919	0.00014384	0.00005352	
DISTPRI	0.11633322	0.07730327	0.01946200	0.00022711	-	0.00892555	0.00238246	-	-	0.00047866	0.00553635	-	-	0.00027760	0.00005457	0.00003919	0.00014384	0.00005352	
DISTSEC	0.04101885	0.03062474	0.00687485	-	-	0.00242346	-	-	-	0.00010726	-	-	-	0.00007448	-	0.00011010	0.00042286	0.00006918	
ENERGY	0.00167954	0.00061057	0.00019707	0.00000226	0.00000008	0.00000262	0.00000211	0.00000043	0.00000035	0.00007594	0.00003688	0.00008604	0.00002587	0.00000061	0.00000059	0.00001022	0.00000255	0.00000255	
CUSTOMER	0.16135740	0.13485381	0.03288641	0.00020234	0.00002547	0.00048818	0.00000710	0.00010542	0.00016996	0.00016996	0.0004862	0.00003023	0.0001023	0.00001023	0.00001023	0.00001023	0.00001023	0.00001023	
TOTAL	1.00000000	0.56435150	0.14063102	0.00136362	0.00005187	0.04582250	0.01236854	0.00213654	0.00091064	0.00283300	0.02818730	0.15913100	0.01772778	0.01248813	0.00028237	0.00022144	0.01174605	0.00191037	
T&D Plant	PRODUCTION	12,793,807	6,273,353	1,586,914	18,553	457	663,985	189,100	14,964	3,159	39,886	434,825	2,904,038	455,589	180,224	4,351	3,142	17,037	4,231
	BULKTRAN	676,927,692	331,926,699	83,964,548	981,673	24,184	35,131,520	10,035,370	791,780	167,131	2,110,379	23,096,835	153,654,323	24,105,460	9,535,732	230,186	166,254	901,460	223,849
	SUBTRAN	259,498,070	123,236,102	31,546,624	367,620	12,052	13,749,551	3,897,279	399,210	-	794,571	8,899,991	72,497,063	-	3,731,550	89,280	61,276	192,485	47,950
	DISTPRI	422,067,976	280,463,602	70,609,973	823,993	-	30,448,976	8,643,806	-	-	1,736,617	20,086,405	-	-	8,263,339	197,983	142,169	521,146	129,968
	DISTSEC	148,661,023	110,990,582	24,915,915	-	-	8,783,123	-	-	-	388,746	-	-	-	2,444,474	-	39,860	880,175	218,148
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	651,213,806	483,757,933	117,296,074	729,413	95,201	1,788,327	612,312	273,161	117,066	25,473	378,355	708,314	175,601	608,786	7,990	36,740	38,689,007	5,913,053
	TOTAL	2,171,162,375	1,336,648,271	329,920,048	2,921,253	131,894	90,565,783	23,347,967	1,479,115	287,356	5,071,137	52,806,411	229,763,738	24,736,649	24,765,104	529,800	449,440	41,201,311	6,537,198
	PRODUCTION	0.00580261	0.00289940	0.00077091	0.00000855	0.00000022	0.00008710	0.00000089	0.00000145	0.00000157	0.00002027	0.00013375	0.00002084	0.00000260	0.00000015	0.00000015	0.00000015	0.00000015	0.00000015
	BULKTRAN	0.31178124	0.15287972	0.03867263	0.00045214	0.00001114	0.01618111	0.00406830	0.00036468	0.00007698	0.00097200	0.01059655	0.07077053	0.01110256	0.00439199	0.00010602	0.00007657	0.00041520	0.00010310
SUBTRAN	0.11952034	0.05670643	0.01452983	0.00000555	0.00000055	0.00633281	0.00179502	0.00018387	-	0.00035467	0.00409418	0.03339090	-	0.00171869	0.00004112	0.00002822	0.00008866	0.00002028	
DISTPRI	0.19439274	0.12917671	0.03232174	0.00037952	-	0.01402427	0.00398119	-	-	0.00079986	0.00925145	-	-	0.00380595	0.00009119	0.00006548	0.00024003	0.00005896	
DISTSEC	0.06847071	0.05112035	0.01147584	-	-	0.00404536	-	-	-	0.00017905	-	-	-	0.00112268	-	0.00018336	0.00040539	0.00010048	
ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CUSTOMER	0.29993786	0.22281057	0.05402455	0.00033596	0.00004385	0.00028367	0.00028202	0.00012581	0.00005392	0.000017426	0.00032624	0.00008086	0.00002808	0.00000808	0.00002468	0.00001692	0.01819490	0.00027345	
TOTAL	1.00000000	0.61563718	0.15195949	0.00134548	0.00006075	0.04171304	0.01057633	0.00066125	0.00013235	0.00233758	0.02432172	0.15825222	0.01139327	0.01140638	0.00003402	0.00020700	0.01879491	0.00301992	
Electric Plant in Service	PRODUCTION	659,537,205	323,399,397	81,807,472	956,454	23,563	34,229,273	9,748,329	771,439	162,837	2,056,163	22,415,782	149,706,894	23,486,183	9,290,756	224,282	161,982	878,301	218,098
	BULKTRAN	698,486,360	342,497,839	86,638,636	1,012,937	24,954	36,250,692	10,324,019	816,996	172,454	2,177,590	23,739,552	158,547,877	24,873,166	9,839,424	237,527	171,548	930,170	230,978
	SUBTRAN	267,766,004	127,162,559	32,551,739	379,333	12,436	14,187,629	4,021,451	411,929	-	794,571	9,183,556	74,806,910	-	3,850,442	92,124	63,228	198,618	49,478
	DISTPRI	446,290,350	296,559,337	74,662,261	871,282	-	32,196,435	9,139,872	-	-	1,836,281	21,239,158	-	-	8,737,570	209,345	150,328	551,054	137,426
	DISTSEC	157,804,596	117,817,190	26,448,398	-	-	9,323,339	-	-	-	412,656	-	-	-	2,594,824	-	42,312	934,312	231,566
	ENERGY	29,773,968	10,823,804	3,493,558	39,995	1,014	1,690,594	471,895	37,360	7,659	112,652	1,346,283	9,517,590	1,525,286	458,567	10,778	10,529	181,177	45,228
	CUSTOMER	719,239,909	537,669,715	129,903,454	811,607	105,339	1,980,663	681,659	302,153	129,418	28,226	421,013	783,453	194,136	675,085	8,913	40,647	39,433,736	6,070,690
	TOTAL	2,978,988,391	1,755,929,841	435,505,518	4,071,607	167,305	129,858,626	34,387,226	2,339,878	472,368	7,418,139	78,345,345	393,362,725	50,078,771	35,446,667	782,970	640,574	43,107,367	6,983,463
	PRODUCTION	0.22143036	0.10856342	0.02746232	0.00032108	0.00000791	0.01149058	0.00327246	0.00025897	0.00005466	0.00089024	0.00752486	0.05025579	0.00788418	0.00311886	0.00007529	0.00005438	0.00029484	0.00007321
	BULKTRAN	0.23447807	0.11497466	0.02908412	0.00034004	0.00000838	0.01216916	0.00346572	0.00027426	0.00005789	0.00073101	0.00796924	0.05222366	0.00834979	0.00330304	0.00007974	0.00005759	0.00031225	0.00007754
SUBTRAN	0.08988759	0.04268778	0.01092744	0.0000417	0.00000417	0.00476271	0.00134998	0.00013828	-	0.00026673	0.00308287	0.02511227	-	0.00129257	0.00003093	0.00002123	0.00006667	0.00001661	
DISTPRI	0.14981725	0.09955336	0.02506372	0.00029248	-	0.01080817	0.003036821	-	-	0.00061643	0.00712987	-	-	0.00293315	0.00000728	0.00005046	0.00018499	0.00004613	
DISTSEC	0.05297415	0.03955059	0.00887858	-	-	0.00312979	-	-	-	0.00013853	-	-	-	0.00087107	-	0.00001420	0.00031364	0.00007774	
ENERGY	0.00999496	0.00363349	0.00117277	0.00001343	0.00000034														

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

Exhibit No.: NMC-1  
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Witness: N. Coon

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	364,310,199	177,892,353	45,146,726	474,231	5,229	18,977,460	5,111,614	350,082	64,760	1,102,056	12,197,988	83,854,334	13,067,041	5,233,661	126,329	91,207	492,328	122,800	
	BULKTRAN	463,817,287	226,643,185	57,480,788	610,189	7,972	24,131,910	6,568,076	461,037	148,364	1,411,186	15,576,609	106,456,959	16,626,570	6,637,009	160,371	115,816	625,311	155,933	
	SUBTRAN	173,250,999	81,967,508	21,038,431	221,995	3,754	9,201,350	2,489,474	225,391	-	501,297	5,868,293	48,946,395	-	2,531,218	60,620	41,602	130,116	32,554	
	DISTPRI	268,534,090	178,469,180	45,081,926	474,061	-	19,507,396	5,266,434	-	-	1,079,697	12,660,862	-	-	5,371,357	128,779	92,461	337,414	84,523	
	DISTSEC	93,405,607	69,643,017	15,680,086	-	-	5,540,246	-	-	-	238,223	-	-	-	1,567,417	-	25,572	562,099	139,948	
	ENERGY	93,604,418	33,984,360	10,979,424	127,287	3,230	5,327,307	1,467,751	114,488	(13,120)	351,267	4,210,943	30,034,113	4,787,884	1,449,672	33,929	33,114	570,534	142,235	
	CUSTOMER	415,327,711	308,656,522	74,994,507	421,883	25,699	1,149,911	375,744	146,277	79,796	15,880	240,582	462,957	114,100	397,932	5,249	23,970	24,489,673	3,767,028	
	TOTAL	1,872,259,310	1,077,256,125	270,341,887	2,329,646	45,885	83,844,580	21,279,093	1,297,274	279,800	4,699,605	50,755,278	269,754,758	34,595,595	23,186,265	515,277	423,743	27,207,476	4,445,022	
	RATEBASE	0.19458320	0.09501480	0.02411350	0.00025329	0.00000279	0.01013613	0.00273018	0.00018698	0.00003459	0.00058862	0.00651512	0.04478778	0.00697929	0.00279537	0.00006747	0.00004872	0.00026296	0.00006559	
	BULKTRAN	0.24773133	0.12105331	0.03070130	0.00032591	0.00000426	0.01288919	0.00350810	0.00024625	0.000007924	0.00075373	0.00831969	0.05686016	0.00888048	0.00354462	0.00008566	0.00006186	0.00033399	0.00008329	
	SUBTRAN	0.09264960	0.04378000	0.01123692	0.00011857	0.00000201	0.00491457	0.00132966	0.00012038	-	0.00026775	0.00313434	0.02614296	-	0.00135196	0.00003238	0.00002222	0.00006950	0.00001739	
	DISTPRI	0.14342783	0.09522290	0.02406821	0.00025320	-	0.01041917	0.00291286	-	-	0.00057668	0.00676234	-	-	0.00286892	0.00006878	0.00004938	0.00018022	0.00004514	
	DISTSEC	0.04988925	0.03719731	0.00837495	-	-	0.00296393	-	-	-	0.00012724	-	-	-	0.00083718	-	0.00001366	0.00030023	0.00007475	
	ENERGY	0.04999543	0.01815152	0.00586426	0.00006799	0.00000173	0.000284539	0.000078395	0.00006115	(0.00000701)	0.000018762	0.00224912	0.01604164	0.00255728	0.00077429	0.00001812	0.00001769	0.00030473	0.00007597	
	RATEBASE	0.22183236	0.16485778	0.04003426	0.00022533	0.00001373	0.00061418	0.000030848	0.000012850	0.00004262	0.00007813	0.00024727	0.00000694	0.00002154	0.000003280	0.000000280	0.00001280	0.01380028	0.00201202	
	CUSTOMER	0.22183236	0.16485778	0.04003426	0.00022533	0.00001373	0.00061418	0.000030848	0.000012850	0.00004262	0.00007813	0.00024727	0.00000694	0.00002154	0.000003280	0.000000280	0.00001280	0.01380028	0.00201202	
	TOTAL	1.00000000	0.57537763	0.14439340	0.00124430	0.00002451	0.04478257	0.01136546	0.00069289	0.00014945	0.00251013	0.02710911	0.14407981	0.01847799	0.01238518	0.00022752	0.000022633	0.01453190	0.00237415	
CUST_451	TOTAL	1.00000000	0.88622070	0.09130891	0.00052047	0.00002818	0.00089344	0.00069616	-	-	-	-	0.00020387	-	-	-	-	0.02012826	-	
	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	0.34540731	0.22052269	0.05778501	0.00067433	-	0.02491850	0.00707382	-	-	0.00142119	0.01643809	-	-	0.00676246	0.00016202	0.00011635	0.00042649	0.00010636	
	DISTSEC	0.12165956	0.06083124	0.02039041	-	-	0.00718783	-	-	-	0.00031814	-	-	-	0.00020048	-	0.00003262	0.00017853	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	0.53293313	0.39589245	0.09599146	0.00059693	0.00007791	0.00146351	0.00050110	0.00022355	0.00009580	0.00002085	0.00030963	0.00057966	0.00014371	0.00049903	0.00000654	0.00003007	0.03166188	0.00483906	
	TOTAL	1.00000000	0.71624638	0.17416688	0.00127126	0.00007791	0.03358984	0.00757492	0.00022355	0.00009580	0.00176018	0.01674772	0.00057966	0.00014371	0.00026197	0.00016856	0.00017903	0.03280868	0.00512395	
	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	0.31613679	0.28399133	0.03029443	0.00027608	-	0.00066319	0.00065011	-	-	-	-	-	-	-	-	-	0.00026165	-	
	DISTSEC	0.12370975	0.11238664	0.01068990	-	-	0.00019130	-	-	-	-	-	-	-	-	-	-	0.00044191	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	0.56015346	0.48984273	0.05032458	0.00024439	0.00002818	0.00003895	0.00004605	-	-	-	-	-	0.00020387	-	-	-	0.01942469	-	
	TOTAL	1.00000000	0.88622070	0.09130891	0.00052047	0.00002818	0.00089344	0.00069616	-	-	-	-	0.00020387	-	-	-	-	0.02012826	-	
364 Poles	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	83,248,203	55,318,319	13,927,030	162,523	-	6,005,721	1,704,894	-	-	342,528	3,961,819	-	-	1,629,852	39,050	28,041	102,790	25,635	
	DISTSEC	35,341,632	26,386,125	5,923,335	-	-	2,088,038	-	-	-	92,418	-	-	-	581,132	-	9,476	209,247	51,861	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	216,002,814	173,907,993	41,130,869	93,458	-	485,982	80,107	-	-	6,676	45,394	-	-	169,560	1,335	10,681	-	70,761	
	TOTAL	334,592,649	255,612,437	60,981,234	255,961	-	8,579,741	1,785,001	-	-	441,622	4,007,213	-	-	2,380,543	40,385	48,198	312,037	148,257	
365 Overhead Lines	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	87,235,847	57,968,103	14,594,144	170,308	-	6,293,399	1,786,560	-	-	358,936	4,151,593	-	-	1,707,922	40,920	29,384	107,714	26,863	
	DISTSEC	37,034,520	27,650,038	6,207,067	-	-	2,188,057	-	-	-	96,845	-	-	-	608,969	-	9,930	219,270	54,345	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	226,340,494	182,238,302	43,101,065	97,935	-	509,260	83,944	-	-	6,995	47,568	-	-	177,682	1,399	11,193	-	74,151	
	TOTAL	350,619,861	267,856,444	63,902,276	268,243	-	8,990,716	1,870,504	-	-	462,776	4,199,161	-	-	2,494,573	42,319	50,507	326,984	155,358	
	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	0.24880464	0.16533035	0.04162384	0.00048574	-	0.01794935	0.00509543	-	-	0.00102372	0.01184072	-	-	0.00487115	0.00011671	0.00008381	0.00030721	0.00007661	
	DISTSEC	0.10562585	0.07886044	0.01770312	-	-	0.00624054	-	-	-	0.00027621	-	-	-	0.00173683	-	0.00002832	0.00062538	0.00015500	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	0.64556951	0.51976035	0.12292819	0.00027932	-	0.00145246	0.00023942	-	-	0.00001995	0.00013567	-	-	0.00050676	0.00000399	0.00003192	-	0.00021148	
	TOTAL	1.00000000	0.76395114	0.18225515	0.00076505	-	0.02564235	0.00533485	-	-	0.00131988	0.01197639	-	-	0.00711475	0.00012070	0.00014405	0.000093259	0.00044310	
366 Underground Conduit	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN																			

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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 581-589	PRODUCTION	Excl. 580 -	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	Acct. 580 allocated on this: TOTOXEXP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
TOTOXEXP	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTOXEXP	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTOXEXP	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTOXEXP	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTOXEXP	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTOXEXP	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Acct 591-598	PRODUCTION	Excl. 590 -	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	Acct. 590 allocated on this: TOTMXPXP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
TOTMXPXP	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Acct 561-574	PRODUCTION	(0)	0	0	0	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	(0)	
	BULKTRAN	6,235,324	3,057,447	773,415	9,042	223	323,607	92,162	7,293	1,539	19,439	211,921	1,415,342	222,040	87,836	2,120	1,531	8,304	2,062	
	SUBTRAN	2,391,300	1,135,633	290,705	3,388	111	126,703	35,914	3,679	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
TOTMXPXP	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
TOTMXPXP	TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
EXP_OM_TRAN	PRODUCTION	8,626,624	4,193,080	1,064,120	12,430	334	450,310	128,075	10,972	1,539	26,535	293,935	2,083,410	222,040	122,222	2,943	2,096	10,077	2,504	
	BULKTRAN	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	0.00000000	
	SUBTRAN	0.72280000	0.35441996	0.08965444	0.00104820	0.00002582	0.03751254	0.01068399	0.00084544	0.00017846	0.00022539	0.02465590	0.16406578	0.02573898	0.01018192	0.00024580	0.00017752	0.00096255	0.00023902	
	DISTPRI	0.27720000	0.13164278	0.03369861	0.00003920	0.00001287	0.01468749	0.00041634	0.00042644	-	0.00050711	0.07744253	-	-	0.00089610	0.00005937	0.00005646	0.00020562	0.00005122	
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	TOTAL	1.00000000	0.48606264	0.12335305	0.00144089	0.00003870	0.05220004	0.01484652	0.00127188	0.00017846	0.00307596	0.03407302	0.24150930	0.02573898	0.01416803	0.00034117	0.00024298	0.00116816	0.00029024	
	Acct 580-598	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTRAN		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
DISTPRI		11,834,788	7,864,209	1,979,904	23,105	-	853,789	242,372	-	-	48,695	563,223	-	-	231,704	5,551	3,886	14,613	3,644	
DISTSEC		4,341,149	3,241,110	727,586	-	-	256,482	-	-	-	11,352	-	-	-	71,383	1,164	15,703	6,370	-	
ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CUSTOMER		25,804,858	20,148,294	4,945,358	43,281	5,948	83,572	36,292	17,065	7,314	1,205	22,526	44,251	10,970	28,274	466	1,677	318,120	90,245	
TOTAL		41,980,795	31,253,605	7,193,843	66,386	5,948	1,193,843	278,665	17,065	7,314	61,251	585,749	44,251	10,970	331,360	6,018	6,827	358,436	100,259	
EXP_OM_DIST		PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	0.28190956	0.18732852	0.04716213	0.00055037	-	0.02033762	0.00577341	-	-	0.00115993	0.01341620	-	-	0.00551929	0.00013224	0.00009496	0.00034809	0.00008681	
	DISTSEC	0.10340798	0.07720458	0.01733141	-	-	0.00610950	-	-	-	0.00027041	-	-	-	0.000170037	-	0.00002773	0.00061225	0.00015174	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	0.61468246	0.47994075	0.11780050	0.00103098	0.00014167	0.00199072	0.00086450	0.00004050	0.00017421	0.00020870	0.00053658	0.00105407	0.00026132	0.00067394	0.00001111	0.00039094	0.00757775	0.00214966	
	TOTAL	1.00000000	0.74447386	0.18229404	0.00158134	0.00014167	0.02843785	0.00063791	0.00004050	0.00017421	0.00145903	0.01395278	0.00105407	0.00026132	0.00078934	0.00014335	0.00016262	0.00083308	0.00238822	
	Acct 560-598	PRODUCTION	(0)	0	0	0	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	0	(0)
		BULKTRAN	6,235,324	3,057,447	773,415	9,042	223	323,607	92,162	7,293	1,539	19,439	211,921	1,415,342	222,040	87,836	2,120	1,531	8,304	2,062
SUBTRAN		2,391,300	1,135,633	290,705	3,388	111	126,703	35,914	3,679	-	-	-	-	-	-	-	-	-	-	
DISTPRI		11,834,788	7,864,209	1,979,904	23,105	-	853,789	242,372	-	-	48,695	563,223	-	-	231,704	5,551	3,886	14,613	3,644	
DISTSEC		4,341,149	3,241,110	727,586	-	-	256,482	-	-	-	11,352	-	-	-	71,383	1,164	15,703	6,370	-	
ENERGY		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
CUSTOMER		25,804,858	20,148,294	4,945,358	43,281	5,948	83,572	36,292	17,065	7,314	1,205	22,526	44,251	10,970	28,274	466	1,677	318,120	90,245	
TOTAL		50,607,419	35,446,684	8,716,969	78,816	6,281	1,644,153	406,740	28,337	8,853	87,787	879,684	2,127,661	233,011	453,583	8,961	8,923	368,513	102,763	
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	(0.00000000)
		BULKTRAN	0.12320968	0.60441499	0.1528264	0.00017868	0.00000440	0.00639445	0.00182111	0.00014411	0.00003042	0.00038412	0.00418754	0.002796709	0.00438751	0.000173653	0.00004190	0.00003026	0.00016408	0.00004074
	SUBTRAN	0.04725197	0.02244005	0.00574432	0.00006994	0.000000219	0.00250365	0.00070966	0.00014022	0.00016260	0.00087946	0.00016260	0.00230986	0.00087946	0.00001626	0.00001116	0.00003026	0.00003873	0.00003026	
	DISTPRI	0.23584719	0.15539620	0.03912280	0.00045655	-	0.01687083	0.00478927	-	-	0.00066231	0.01112925	-	-	0.00457846	0.00010970	0.00007877	0.00002875	0.00007201	
	DISTSEC	0.08578089	0.06044416	0.01437707	-	-	0.00506807	-	-	-	0.00002242	-	-	-	0.00141052	-	0.00002300	0.00005078	0.00012588	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER																			

KENTUCKY POWER COMPANY  
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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	4,966,908	4,156,216	803,019	1,860	81	10,069	1,692	197	57	145	996	497	88	3,379	27	200	(12,827)	1,214	
	TOTAL	4,966,908	4,156,216	803,019	1,860	81	10,069	1,692	197	57	145	996	497	88	3,379	27	200	(12,827)	1,214	
	TOTOX234	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTOX234	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTOX234	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
TOTOX234	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
TOTOX234	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
TOTOX234	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
TOTOX234	CUSTOMER	1,000,000.00	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00020043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436	
TOTOX234	TOTAL	1,000,000.00	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00020043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436	
Acct 901-905	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	5,010,225	4,192,462	810,022	1,877	82	10,157	1,706	199	57	147	1,004	501	89	3,408	28	201	(12,939)	1,224	
	TOTAL	5,010,225	4,192,462	810,022	1,877	82	10,157	1,706	199	57	147	1,004	501	89	3,408	28	201	(12,939)	1,224	
	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	1,000,000.00	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00020043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436	
EXP_OM_CUSTACCT	TOTAL	1,000,000.00	0.83678126	0.16167385	0.00037454	0.00001629	0.00202720	0.00034060	0.00003962	0.00001143	0.00002926	0.00020043	0.00010002	0.00001779	0.00068023	0.00000550	0.00004021	(0.00258259)	0.00024436	
A&G Regulatory																				
Acct 907-910	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	CUSTOMER	1,776,402	1,113,351	263,318	598	26	3,111	513	60	17	43	291	145	26	1,086	9	68	393,289	453	
	TOTAL	1,776,402	1,113,351	263,318	598	26	3,111	513	60	17	43	291	145	26	1,086	9	68	393,289	453	
	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	1,000,000.00	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00028870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501	
EXP_OM_CUSTSERV	TOTAL	1,000,000.00	0.62674481	0.14823101	0.00033681	0.00001443	0.00175142	0.00028870	0.00003368	0.00000962	0.00002406	0.00016359	0.00008180	0.00001443	0.00061107	0.00000481	0.00003849	0.22139623	0.00025501	
O&M Expense less Purch. Power & Fuel	PRODUCTION	120,253,759	59,008,624	14,915,631	159,114	2,888	6,208,628	1,785,872	138,279	88,869	377,686	4,113,638	27,191,228	4,308,842	1,682,915	41,129	29,788	160,512	40,118	
	BULKTRAN	9,950,173	4,918,564	1,250,491	12,302	(176)	520,269	151,062	11,696	(99,935)	31,517	345,797	2,291,450	353,784	140,419	3,470	2,529	13,516	3,418	
	SUBTRAN	3,857,680	1,827,022	469,990	4,633	(72)	203,717	58,840	5,901	-	11,503	133,784	1,081,481	54,984	1,346	932	2,886	732	-	
	DISTPRI	14,592,522	9,700,932	2,442,449	22,681	-	1,041,624	302,766	-	-	60,937	704,900	-	-	281,525	6,944	5,025	18,138	4,601	
	DISTSEC	5,347,399	3,995,413	896,917	-	-	312,797	-	-	-	14,190	-	-	-	86,715	-	1,465	31,872	8,029	
	ENERGY	(27,142,166)	(9,943,422)	(3,188,923)	(47,604)	(2,019)	(1,571,626)	(423,997)	(36,228)	93,997	(99,997)	(1,200,714)	(8,814,262)	(1,356,184)	(427,996)	(9,466)	(164,171)	(40,922)	-	
	CUSTOMER	38,881,461	30,637,286	7,202,298	47,555	3,358	114,686	45,828	(1,548)	-	1,679	28,389	52,617	38,695	599	2,352	561,240	122,335	-	
	TOTAL	165,740,827	100,244,419	23,988,854	198,681	3,979	6,830,094	1,920,371	139,614	72,382	397,515	4,125,794	21,802,515	3,319,566	1,857,257	43,842	32,755	624,047	139,141	
	EXP_OM_LPP	PRODUCTION	0.7255303	0.3560290	0.0899930	0.00096002	0.00001742	0.03745986	0.00075909	0.00063431	0.00025619	0.00022787	0.02481970	0.16405872	0.02599747	0.00151389	0.00024815	0.00017973	0.00096845	0.000204205
	EXP_OM_LPP	BULKTRAN	0.06003453	0.02967624	0.00754486	0.00007422	(0.00000186)	0.00313905	0.00091144	0.00007057	(0.00006296)	0.00019016	0.00208637	0.000213456	0.00084722	0.00002094	0.00001526	0.00008155	0.00002662	-
EXP_OM_LPP	SUBTRAN	0.02327537	0.01102337	0.00283669	0.00002796	(0.00000043)	0.00122913	0.00035501	0.00003560	-	0.00000690	0.00008079	0.00052513	-	0.00005621	0.00000812	0.00000562	0.00001742	0.00000442	
EXP_OM_LPP	DISTPRI	0.08804422	0.05853073	0.01473656	0.00013684	-	0.00628466	0.00182674	-	-	0.00036767	0.00425303	-	-	0.00189859	0.00000490	0.00003032	0.00010944	0.00002776	
EXP_OM_LPP	DISTSEC	0.03226362	0.02410639	0.00541157	0.000188726	-	0.00188726	-	-	-	0.00008561	-	-	-	0.00052320	0.00000884	0.00001920	0.00004845	-	
EXP_OM_LPP	ENERGY	(0.16378270)	(0.05939045)	(0.01920402)	(0.000028722)	(0.00001218)	(0.00048243)	(0.00255819)	(0.00021858)	0.00056713	(0.00724453)	(0.00518099)	(0.00818256)	(0.000258232)	(0.000045820)	(0.00005633)	(0.000099020)	(0.000024190)	-	
EXP_OM_LPP	CUSTOMER	0.23459193	0.18485057	0.04345518	0.00028693	0.00002026	0.00069196	0.00027650	0.00012047	(0.00006364)	0.00001013	0.00017129	0.00031747	0.00007918	0.00023347	0.00000361	0.00001419	0.00338625	0.00073811	
EXP_OM_LPP	TOTAL	1,000,000.00	0.60482634	0.14473714	0.00119875	0.00002041	0.04120948	0.01158695	0.00084236	0.00043672	0.000239841	0.02489305	0.13154583	0.02002866	0.01120579	0.00026452	0.00019763	0.00376520	0.00083951	
O&M Labor	PRODUCTION	7,984,127	3,914,960	990,333	11,578	285	414,368	118,010	9,339	1,971	24,891	271,358	1,812,29							



KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

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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	7,984,127	3,914,960	990,333	11,578	285	414,368	118,010	9,339	1,971	24,891	271,358	1,812,299	284,316	112,471	2,715	1,961	10,632	2,640
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	5,758,873	2,093,537	675,723	7,736	196	326,994	91,274	7,226	1,481	21,789	260,398	1,840,890	295,020	88,696	2,085	2,037	35,043	8,748
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	13,743,000	6,008,498	1,666,056	19,314	481	741,362	209,284	16,565	3,453	46,680	531,755	3,653,189	579,336	201,167	4,800	3,997	45,676	11,398
	LABOR_PROD	0.58099554	0.28486940	0.07206088	0.00084250	0.00002076	0.03015118	0.00858691	0.00067953	0.00014344	0.00171119	0.01974515	0.13187072	0.02068802	0.00818385	0.00019756	0.00014268	0.00077366	0.00019211
	LABOR_PROD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LABOR_PROD	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTPRI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTSEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	0.41904046	0.15233482	0.04916852	0.00056289	0.00001427	0.02379352	0.00664148	0.00052581	0.00010779	0.00158547	0.01894766	0.13395108	0.02146696	0.00645389	0.00015169	0.00014819	0.00254989	0.00063654
	CUSTOMER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	1.00000000	0.43720421	0.12122940	0.00140539	0.00003502	0.05394470	0.01522839	0.00120534	0.00025123	0.00339666	0.03869281	0.26582180	0.04215498	0.01463774	0.000334925	0.00029087	0.00332355	0.00082865
	LABOR_PROD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	LABOR_PROD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rent Revenues	PRODUCTION	2,318,388	1,136,805	287,567	3,362	83	120,322	34,267	2,712	572	7,228	78,795	526,246	82,558	32,659	788	569	3,087
BULKTRAN		411,623	201,837	51,057	597	15	21,363	6,084	481	102	1,283	13,990	93,433	14,658	5,798	140	101	548	136
SUBTRAN		157,861	74,968	19,191	224	7	8,364	2,371	243	-	468	5,414	44,102	-	2,270	54	37	117	29
DISTPRI		1,590,338	1,056,777	266,056	3,105	-	114,731	32,570	-	-	6,544	75,685	-	-	31,136	746	536	1,964	490
DISTSEC		648,050	484,582	106,782	-	3	38,347	-	-	-	1,697	-	-	-	10,673	-	174	3,843	924
ENERGY		2,330	847	273	-	0	132	-	-	-	9	105	745	119	36	1	14	-	4
CUSTOMER		3,748,486	2,983,353	708,037	2,008	82	8,712	1,710	235	101	120	996	610	151	3,027	27	189	33,032	6,096
TOTAL		8,878,076	5,939,170	1,440,963	9,298	187	311,971	77,038	3,674	775	17,350	174,985	665,136	97,486	85,599	1,756	1,608	42,605	8,474
LABOR_PROD		0.26113628	0.12804633	0.03239074	0.00037870	0.00000933	0.01355269	0.00385974	0.00030544	0.00006447	0.00008411	0.00887527	0.05627475	0.00029609	0.00367857	0.00006880	0.00006414	0.00034775	0.00008635
LABOR_PROD		0.04636401	0.02273426	0.00575088	0.00006724	0.00000166	0.00240624	0.00085829	0.00005423	0.00001145	0.00014454	0.00157578	0.01054026	0.00165103	0.00065312	0.00001577	0.00001139	0.00006174	0.00001533
LABOR_PROD	0.01778100	0.00844423	0.00216160	0.00002519	0.00000083	0.00094213	0.00026704	0.00002735	-	0.00001456	0.00005476	0.00006983	0.000496755	-	0.00002569	0.00000612	0.00000420	0.00000329	
LABOR_PROD	0.17913091	0.11903225	0.02967575	0.00034871	-	0.01252292	0.00366854	-	-	0.00073704	0.00852492	-	-	0.00350706	0.00008403	0.00006034	0.00022118	0.00005516	
LABOR_PROD	0.07310703	0.05458184	0.12226290	-	-	0.00431928	-	-	-	0.00019117	-	-	-	0.001120212	0.00001980	0.000043284	0.00010728	-	
LABOR_PROD	0.00026248	0.00009542	0.00003080	0.00000051	0.00000001	0.00000416	0.00000033	0.00000007	0.00000009	0.00001187	0.00000390	0.00001345	0.00000040	0.00000010	0.00000009	0.00000160	0.00000040	0.00000040	
LABOR_PROD	0.42221829	0.33603604	0.07975115	0.00022612	0.00000923	0.00098131	0.00019257	0.00002648	0.00001135	0.00001957	0.00012116	0.00006866	0.00001702	0.00034101	0.00000299	0.00002132	0.00372065	0.00068667	
LABOR_PROD	1.00000000	0.68897036	0.16230562	0.00104731	0.00002105	0.03513948	0.00867734	0.00041383	0.00006734	0.00195420	0.01970984	0.07491893	0.01098058	0.00964161	0.00019780	0.00016107	0.00374985	0.00095488	
Total Revenues	PRODUCTION	184,903,617	85,134,744	25,261,948	276,062	4,443	11,610,515	3,862,678	230,541	254,826	645,286	7,529,918	40,257,343	6,216,719	3,389,903	78,718	59,547	307,827	82,604
	BULKTRAN	55,016,646	19,880,623	8,853,137	159,371	5,069	5,995,692	1,851,844	95,770	148,844	247,713	3,356,475	19,752,870	1,355,943	1,827,586	37,982	30,528	150,699	44,188
	SUBTRAN	21,631,475	7,538,559	3,686,377	59,097	2,453	2,172,313	713,244	48,092	-	90,207	1,289,842	5,247,885	-	707,408	14,606	11,137	31,896	9,359
	DISTPRI	51,779,502	27,463,943	10,677,087	142,796	-	5,758,653	1,857,636	-	-	265,604	3,599,867	-	-	1,811,448	39,001	30,556	103,305	29,605
	DISTSEC	17,505,060	11,179,056	3,818,660	-	-	1,674,256	-	-	-	60,255	-	-	-	538,558	-	8,617	175,732	49,925
	ENERGY	238,665,417	85,064,280	28,502,433	294,290	5,898	14,007,242	4,029,233	298,159	465,919	930,371	11,270,876	75,137,847	12,165,845	3,859,070	90,946	90,046	1,523,363	389,600
	CUSTOMER	95,963,787	65,201,624	21,772,486	157,172	17,824	405,962	162,300	53,959	(87,400)	4,899	86,869	110,511	25,499	156,453	1,979	9,256	6,656,053	1,228,222
	TOTAL	665,465,504	302,002,829	103,581,129	1,088,788	35,687	41,224,663	12,177,025	726,521	184,501	2,244,330	27,133,847	131,726,455	19,764,006	12,290,425	263,233	239,686	8,948,875	1,833,502
	LABOR_PROD	0.27785605	0.12793262	0.03796132	0.00041484	0.00000668	0.01744721	0.00535366	0.00034644	0.00038293	0.00009667	0.01131526	0.06949501	0.00934191	0.00509403	0.00011829	0.00008948	0.00046257	0.00012413
	LABOR_PROD	0.08267393	0.02987476	0.01480638	0.00023949	0.00000762	0.00840869	0.00276278	0.00014391	(0.00067448)	0.00037224	0.00504380	0.01648901	0.00203759	0.00274633	0.00005768	0.00004587	0.00022646	0.00008640
LABOR_PROD	0.03250578	0.01132825	0.0055307	0.00008881	0.00000369	0.00328435	0.00107180	0.00007227	-	0.00013556	0.00193826	0.00178804	-	0.00106303	0.00001674	0.00004793	0.00001406	-	
LABOR_PROD	0.07780945	0.04127027	0.01604454	0.00021458	-	0.00865357	0.00279148	-	-	0.00039913	0.00540955	-	-	0.00272208	0.00005861	0.00004592	0.00015524	0.00004449	
LABOR_PROD	0.02630489	0.01679885	0.00573833	-	-	0.00251592	-	-	-	0.00009555	0.00540955	-	-	0.00080630	0.00001295	0.00002607	0.00007502	-	
LABOR_PROD	0.35864431	0.12863819	0.04263082	0.00044223	0.00000886	0.002104879	0.00065476	0.00004805	0.00070014	0.00138908	0.01693683	0.11291020	0.01828171	0.00579805	0.00013667	0.00013531	0.00228917	0.00058545	
LABOR_PROD	0.14420550	0.09797897	0.03271768	0.00023618	0.00002678	0.00061009	0.00024402	0.00008108	(0.00013134)	0.00000736	0.00013054	0.00016607	0.00003832	0.00023510	0.00000297	0.000001391	0.01000210	0.00184566	
LABOR_PROD	1.00000000	0.45382191	0.15656214	0.01636313	0.00005363	0.01829581	0.00109175	0.00027725	0.00037257	0.04077424	0.19794633	0.02969652	0.01848891	0.00039556	0.000036018	0.01344754	0.00275522	-	
RBASE	PRODUCTION	601,658,147	271,946,349	96,300,861	1,100,232	49,001	38,192,214	11,115,242	651,448	85,418	2,053,559	24,627,847	115,694,963	18,226,321	11,514,536	241,795	221,865	8,755,836	1,781,053
	Revenues:	486,696,401	31,861,890	9,024,810	96,366	3,781	3,532,641	1,100,784	92,132	8,584	190,771	2,538,811	1,537,685	1,537,685	336,954	22,029	18,021	243,375	52,449
Initial Total Expense		589,874,740	285,126,664	81,572,632	827,400	26,742	30,555,580	8,651,049	617,207	168,315	1,844,670								

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ALLOCATOR	FUNCTION	Total	RS	GS-SEC	GS-PR	GS-SUB	LG-SEC	LG-PR	LG-SUB	LG-TRA	IGS-SEC	IGS-PR	IGS-SUB	IGS-TRA	PS-SEC	PS-PR	MW	OL	SL
Total Expenses	PRODUCTION	171,139.636	82,816.879	21,718.811	204,188	4,882	9,277.780	2,721.806	204,426	133,253	551,560	6,106.763	38,357.352	6,033.754	2,563.296	61,814	45,133	240,862	61,287
	BULKTRAN	35,241,822	15,850.033	5,023.386	68,742	1,849	2,406.211	754.252	51,192	(189,053)	127,704	1,524.126	7,658.302	1,123.138	713,927	15,999	122,635	63,120	17,119
	SUBTRAN	13,997.376	6,080.912	1,927.665	26,125	934	996.195	297.228	26,299	-	47,576	599.528	3,723.989	-	282,685	6,297	4,562	13,672	4,562
	DISINTRC	39,130.867	24,543.434	6,965.669	82,702	-	3,234.605	181.664	-	-	37,786	194.165	-	-	243,091	21,414	59,944	66,647	59,944
	CUSTOMER	13,974.761	1,001.965	2,527.888	-	-	956.645	-	-	-	39,996	-	-	-	280,324	-	4,575	97,705	27,630
	ENERGY	259,895.621	85,532.119	27,780.830	302,619	6,710	13,466.083	3,796.102	214,259	225,738	900,499	10,788.783	75,052.131	12,098.805	3,663.665	86,488	78,812	1,451,169	364,309
	CUSTOMER	80,494.558	10,292.384	2,907.998	107,620	1,131	15,628.384	3,906.988	49,131	(211,774)	128,641	97.713	23,901	-	1,267	5,467	1,267	5,467	1,267
	TOTAL	585,874.740	285,126.664	91,572.632	827,400	26,742	30,555.880	8,696.104	69,157	188,315	1,844,670	21,192.018	124,889.487	19,279.598	8,021.164	193,075	174,919	3,154,730	1,061,889
	PRODUCTION	188,781.774	85,801.855	25,518.557	315,343	7,850	11,805.844	3,576.176	218,529	116,054	645,280	7,542.634	49,018.321	6,216.719	3,504.834	78,957	59,547	310,071	82,684
	BULKTRAN	55,150.370	19,780.437	9,861.221	166,444	6,374	5,620.520	1,854.629	96,104	(208,907)	247,713	3,572.721	10,909.570	1,355.943	1,839.448	38,016	30,528	151,023	44,161
Total Revenue	SUBTRAN	21,587.978	7,922.377	2,592.377	43,520	3,065	2,181.844	714.320	45,252	-	71,539	60.207	1,230.312	-	218.945	14,137	31,963	9,589	9,589
	DISINTRC	52,162.022	27,638.413	10,758.278	157,831	-	5,833.264	1,883.972	-	-	265,604	3,604.534	-	-	1,836.983	39,093	30,556	103,888	29,605
	CUSTOMER	17,634.856	11,249.731	3,847.593	-	-	1,696.883	-	-	-	60,255	-	-	-	546.130	-	8,617	176,722	49,925
	ENERGY	240,271.748	28,704.927	8,469.489	322,791	8,543	14,175.755	4,042.000	211,755	235.32	229,222	11,284.473	75,969.393	12,165.845	3,909.534	91,146	90,046	1,531,372	390,046
	CUSTOMER	96,660.400	56,613.956	21,936.883	173,883	26,950	411,246	162,948	55,381	(42,367)	4,899	86,983	111,852	25,499	158,654	1,984	9,256	6,694,171	1,228,222
	TOTAL	670,254.548	303,808.239	104,325.790	1,196,599	52,782	41,724.854	12,216.026	743,580	94,002	2,244.330	13,127.657	133,127.981	19,764.006	12,453.490	263,814	239,686	8,999,210	1,833,502
	PRODUCTION	(60,068.731)	(26,646.966)	(7,321.997)	(85,527)	(1,915)	(1,108.520)	(838.972)	(66,495)	(14,928)	(195,854)	(2,002.287)	(6,384.802)	(2,153.050)	(851.712)	(20,581)	(14,849)	(80,303)	(19,944)
	BULKTRAN	71,133.413	30,466.886	10,346.886	103,466	2,835	3,694.465	1,080.964	83,359	3,598	221,481	16,134.924	1,080.964	532.456	-	1,001,799	7,466	94,736	23,517
	SUBTRAN	27,279.555	12,052.321	3,317.662	38,759	1,311	1,446.550	413.337	12,440	-	80,850	937.351	7,616.080	-	392.192	9,383	5,000	20,237	5,000
	DISINTRC	2,069.255	1,358.276	367.586	4,401	-	136.319	58.211	-	-	4,825	10.516	-	-	33.815	810	582	2,382	532
Total Other Revenue	CUSTOMER	811.943	603.085	144.825	1,443	-	144.825	-	-	-	14.487	-	-	-	1.487	-	187	1,023	187
	ENERGY	22,971,241	8,217.963	2,792.569	31,929	960	1,308.930	403.335	32,150	5,815	78,074	1,078.446	7,325.967	1,158.072	348.166	8,183	7,994	138,320	34,339
	CUSTOMER	4,499.725	3,504.945	897.479	3,340	791	10.114	3.911	1,075	138	87	1.589	2.149	207	3,226	29	201	63,453	7,992
	ENERGY	68,696.401	31,861.890	9,024.810	98,365	3,781	3,532.641	1,100.784	92.132	8,984	190,771	2,538.011	17,433.518	1,537.685	938.954	22,029	18,021	243,375	52,446
	TOTAL	246,855.905	115,548.821	32,840.554	400,870	9,765	14,914.364	4,417.149	305,023	130,981	841,134	9,544.921	54,563.123	8,369.769	4,302.546	99,518	74,396	390,374	102,598
	PRODUCTION	(15,983.043)	(5,590.899)	1,034.535	61,979	3,739	1,926.269	793.665	12,745	(228.466)	26,232	935.525	(2,225.354)	-	(1,176.513)	837.649	13,832	13,062	56,287
	BULKTRAN	(5,691.578)	(4,549.943)	380.690	22,548	1,754	735.394	300.964	6,211	-	9,357	352.962	(2,297.235)	-	-	319.744	5,235	4,697	11,727
	SUBTRAN	50,092.767	20,020.137	6,880.695	65,951	-	5,696.945	1,055.761	220,779	-	1,803.169	503.018	-	-	29.974	101,508	38,283	29,073	20,073
	DISINTRC	16,822.914	10,645.746	3,702.768	-	-	1,651.286	-	-	-	58.947	-	-	-	534.663	-	8,430	172,171	48,902
	ENERGY	217,300.547	77,903.475	25,912.338	290,863	7,583	12,866.824	3,638.665	273.162	223.408	852.297	10,206.027	68,643.426	11,007.773	3,561.338	82,962	82,051	1,393,052	355,261
Year End Mrg Revenue	CUSTOMER	92,140.975	21,038.011	7,216.031	101,011	26	170.543	54.308	17	(42,505)	401.137	110.704	55.292	-	9.054	-	-	120,230	178
	ENERGY	601,558.147	271,346.349	95,300.981	1,100,232	49,001	38,122.214	11,115.242	651.448	65,418	2,053.559	24,627.947	115,694.663	18,226.321	11,514.538	241,785	221,665	8,755,836	1,781,053
	TOTAL	4,013,068.4	1,912,082.255	605,492.048	5,000,663.9	0.0001623	4,024,792.89	0.00734285	0.00057076	0.00021774	0.00139826	0.01586700	0.09070299	0.01301348	0.00016543	0.00012367	0.00004894	0.00017055	0.00034486
	PRODUCTION	(6,025,694.1)	(2,058,035.6)	0.00117976	0.00010303	0.00000622	(6,032,023.1)	0.00131935	0.00002119	(0.00037647)	0.00043651	(0.00155517)	(0.00886873)	(0.00195578)	-	0.00022199	0.00002171	0.00003347	0.00003436
	BULKTRAN	(9,094,641.9)	(3,005,624.9)	0.00005294	0.00000222	0.00000000	(9,094,641.9)	0.00002228	0.00000000	0.00000103	0.00000000	(0.00000000)	(0.00000000)	(0.00000000)	-	0.00000000	0.00000000	0.00000000	0.00000000
	SUBTRAN	0.0832710	0.0436878	0.0177226	0.00025505	-	0.00947032	0.00300181	-	-	0.00043351	0.00682341	-	-	0.00029750	0.00006364	0.00004983	0.00016874	0.00004833
	DISINTRC	0.0279657	0.0176965	0.0061530	-	-	0.00274051	0.00006473	0.00000979	-	0.00009779	-	0.00009779	-	0.00008880	-	0.00001401	0.00012821	0.00008129
	ENERGY	0.361222043	0.1403753	0.0430753	0.00004832	0.00001261	0.361222043	0.00004832	0.00004540	0.000037138	0.00004540	0.01141682	0.01141682	0.0128277	0.00008880	0.00013791	0.00013640	0.00021574	0.00021574
	CUSTOMER	0.15320327	0.10324690	0.03497485	0.00003360	0.00004349	0.00006682	0.00002648	0.00000928	(0.00007066)	0.00000800	0.00011695	0.00010843	0.00004024	0.00003888	0.00000325	0.00001505	0.00126657	0.00020285
	TOTAL	1.00000000	0.45206993	0.15842356	0.00182897	0.00008146	0.06348881	0.01847742	0.00108293	0.00014199	0.000341373	0.040490093	0.19232499	0.03029852	0.01914119	0.00041903	0.00036848	0.01455526	0.00296073
Calculation of CUST_DEP Allocator																			
CUST_DEP	PRODUCTION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	BULKTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTRAN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DISINTRC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	ENERGY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CUSTOMER	1.00000000	0.66386348	0.14340656	0.00838631	0.00170076	0.03473474	0.03745899	0.00725892	0.00043171	0.00563440	0.04169885	0.04152643	0.00958650	0.00075360	-	-	0.00354587	-
	TOTAL	1.00000000	0.66386348	0.14340656	0.00838631	0.00170076	0.03473474	0.03745899	0.00725892	0.00043171	0.00563440	0.04169885	0.04152643	0.00958650	0.00075360	-	-	0.00354587	-
RB_GUP	PRODUCTION	0.22140036	0.07746232	0.00001024	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
	BULKTRAN	0.23447801	0.11749466	0.02908142	0.00003404	0.00000838	0.01216916	0.00346572	0.00027426	0.00005789	0.00073101	0.00709624	0.05323636	0.00033034	0.00003479	0.00000774	0.00000579	0.00001225	0.00007524
	SUBTRAN	0.08889759	0.04268775	0.01092744	0.00001274	0.00000417	0.00476271	0.00134908	0.00013828	-	0.00026673	0.00308287	0.02511227	-	0.00129257	0.00003093	0.00000213	0.00006667	0.00001661
	DISINTRC	0.14891725	0.09955336	0.02508372	0.00002924	-	0.00176187	0.00306821	-	-	0.00016143	0.00172987	-	-	0.00023315	0.00000708	0.00000000	0.00001849	0.00000000
	ENERGY	0.05297415	0.03650569	0.00817658	0.00012979	-	0.00176187	0.00306821	-	-	0.00013853	0.00172987	-	-	0.00007710	0.00000000	0.00000000	0.00001364	0.00000000
	CUSTOMER	0.00999496	0.00633499	0.00117277	0.00000134	0.00000034	0.00056752	0.00001584	0.00001254	0.00000257	0.00003078	0.000405194	0.000319500	0.000051203	0.00001594	0.00000382	0.00000033	0.00000682	0.00000518
	ENERGY	0.24144403	0.18042808	0.04360788	0.00002745	0.00000356	0.00066490	0.00022983	0.00101743	0.00004345	0.00000000	0.00014133	0.00026300	0.00006517	0.00002262	0.00000299	0.00001364	0.00023769	0.00020370
	CUSTOMER	0.00000000	0.14619834	0.00000000	0.00000000	0.00000000	0.014340624	0.000049											

KENTUCKY POWER COMPANY  
COST-OF-SERVICE STUDY  
TWELVE MONTHS ENDING  
MAY 31, 2025

Exhibit No.: NMC-1  
Page 30 of 30  
Witness: N. Coon

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
REVVEEC_FXNL is a spreading of the REVVEEC allocator to each function within the tariff classes using the RSALE allocator.																			
REVVEEC TOTAL		1.00000000	0.38716930	0.08391101	0.02793506	0.00452702	0.08805098	0.00157715	0.00451748	(0.02396616)	-	0.00868880	0.37115570	-	0.03310382	-	-	0.01332983	-
RSALE	PRODUCTION	0.41036084	0.19208255	0.05459248	0.00066639	0.00001623	0.02470289	0.00734285	0.00050706	0.00021774	0.00139826	0.01586700	0.09070299	0.01391348	0.00715234	0.00016543	0.00012367	0.00064894	0.00017055
	BULKTRAN	(0.02656941)	(0.02508635)	0.00171976	0.00010303	0.00000622	0.00320213	0.00131935	0.00002119	(0.00037647)	0.00004361	0.00155517	(0.00868637)	(0.00195578)	0.000136247	0.00002299	0.00002171	0.00009357	0.00003436
	SUBTRAN	(0.00946139)	(0.00905971)	0.00063284	0.00003748	0.00000292	0.00122248	0.00050031	0.00001033	-	0.00001555	0.00058675	(0.00398504)	-	0.00053153	0.00000870	0.00000781	0.00001949	0.00000718
	DISTPRI	0.08327170	0.04368678	0.01772296	0.00025505	-	0.00947032	0.00300181	-	-	0.00043351	0.00582324	-	-	0.00299750	0.00006364	0.00004983	0.00016874	0.00004833
	DISTSEC	0.02796557	0.01769955	0.00615530	-	-	0.00274501	-	-	-	0.00009799	-	-	-	0.00088880	-	0.0001401	0.00028621	0.00008129
	ENERGY	0.36122943	0.12950282	0.04307537	0.00048352	0.00001261	0.02138916	0.00064873	0.00045409	0.00037138	0.00141682	0.01696599	0.11410938	0.01829877	0.00592019	0.00013791	0.00013640	0.00231574	0.00059057
	CUSTOMER	0.15320327	0.10324690	0.03497485	0.00028350	0.00004349	0.00066682	0.00026438	0.00009028	(0.00007066)	0.00001495	0.00018403	0.00004204	0.00025838	0.00000325	0.00001505	0.01102257	0.0002845	0.00202845
	TOTAL	1.00000000	0.45206993	0.15842356	0.00182897	0.00008146	0.06348881	0.01847742	0.00108293	0.00041199	0.00341373	0.04094009	0.19232499	0.03029852	0.01914119	0.00040193	0.00036848	0.01455526	0.00296073
REVVEEC_FXNL	PRODUCTION	0.38625222	0.16405955	0.02891559	0.01017816	0.00008213	0.03438461	0.00062675	0.00211519	(0.00675010)	-	0.00336749	0.17504191	-	0.01236955	-	-	0.00059430	-
	BULKTRAN	0.03558840	(0.02148487)	0.00091089	0.00157365	0.00034545	0.00444095	0.00001261	0.00008838	0.06354065	-	0.00033006	(0.01676326)	-	0.00240821	-	-	0.0008569	-
	SUBTRAN	(0.01153696)	(0.00775907)	0.00033519	0.00057250	0.00016207	0.00169543	0.00004270	0.00004307	-	-	0.00012453	(0.00769048)	-	0.00091925	-	-	0.00001785	-
	DISTPRI	0.07942420	0.03741498	0.00914884	0.00399560	-	0.01313413	0.00025622	-	-	-	0.00123588	-	-	0.00518403	-	-	0.00015453	-
	DISTSEC	0.02402279	0.01515632	0.00326023	-	-	0.00380699	-	-	-	-	-	-	-	-	-	-	0.00026211	-
	ENERGY	0.34737666	0.11091097	0.02281541	0.00738505	0.00070060	0.02966407	0.00051629	0.00189425	(0.06268257)	-	0.00360073	0.22021240	-	0.01023870	-	-	0.00212077	-
	CUSTOMER	0.13787269	0.08842443	0.01852486	0.04330111	0.00241677	0.000902480	0.00002257	0.00037659	0.01192588	-	0.00003013	0.00035514	-	0.00044685	-	-	0.01009457	-
REVVEEC_FXNL	TOTAL	1.00000000	0.38716930	0.08391101	0.02793506	0.00452702	0.08805098	0.00157715	0.00451748	(0.02396616)	-	0.00868880	0.37115570	-	0.03310382	-	-	0.01332983	-
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	0.00010530	0.49774998	0.00571055	0.00118925	0.07268945	0.13204632	0.00871798	-	(0.01735771)	0.13120736	0.16241781	-	-	-	-	0.00462370	-
RSALE	PRODUCTION	0.41036084	0.19208255	0.05459248	0.00066639	0.00001623	0.02470289	0.00734285	0.00050706	0.00021774	0.00139826	0.01586700	0.09070299	0.01391348	0.00715234	0.00016543	0.00012367	0.00064894	0.00017055
	BULKTRAN	(0.02656941)	(0.02508635)	0.00171976	0.00010303	0.00000622	0.00320213	0.00131935	0.00002119	(0.00037647)	0.00004361	0.00155517	(0.00868637)	(0.00195578)	0.000136247	0.00002299	0.00002171	0.00009357	0.00003436
	SUBTRAN	(0.00946139)	(0.00905971)	0.00063284	0.00003748	0.00000292	0.00122248	0.00050031	0.00001033	-	0.00001555	0.00058675	(0.00398504)	-	0.00053153	0.00000870	0.00000781	0.00001949	0.00000718
	DISTPRI	0.08327170	0.04368678	0.01772296	0.00025505	-	0.00947032	0.00300181	-	-	0.00043351	0.00582324	-	-	0.00299750	0.00006364	0.00004983	0.00016874	0.00004833
	DISTSEC	0.02796557	0.01769955	0.00615530	-	-	0.00274501	-	-	-	0.00009799	-	-	-	0.00088880	-	0.0001401	0.00028621	0.00008129
	ENERGY	0.36122943	0.12950282	0.04307537	0.00048352	0.00001261	0.02138916	0.00064873	0.00045409	0.00037138	0.00141682	0.01696599	0.11410938	0.01829877	0.00592019	0.00013791	0.00013640	0.00231574	0.00059057
	CUSTOMER	0.15320327	0.10324690	0.03497485	0.00028350	0.00004349	0.00066682	0.00026438	0.00009028	(0.00007066)	0.00001495	0.00018403	0.00004204	0.00025838	0.00000325	0.00001505	0.01102257	0.0002845	0.00202845
	TOTAL	1.00000000	0.45206993	0.15842356	0.00182897	0.00008146	0.06348881	0.01847742	0.00108293	0.00041199	0.00341373	0.04094009	0.19232499	0.03029852	0.01914119	0.00040193	0.00036848	0.01455526	0.00296073
FORF_DISC_FXNL	PRODUCTION	0.37973260	0.00004474	0.17152379	0.00208064	0.00023699	0.02838581	0.05283229	0.00408197	-	(0.00710968)	0.05085154	0.07595837	-	-	-	-	0.00020815	-
	BULKTRAN	0.01659593	(0.00002584)	0.00540330	0.00032169	0.00008075	0.00369518	0.00494281	0.00017056	(0.00022172)	0.00498410	(0.00733351)	-	-	-	-	-	0.00002072	-
	SUBTRAN	0.00567050	(0.00000211)	0.00198831	0.00011703	0.00004258	0.00139964	0.000356974	0.00008312	-	(0.00007709)	0.00188044	(0.00336536)	-	-	-	-	0.00000619	-
	DISTPRI	0.10402933	0.00001018	0.05426982	0.00079635	-	0.01084273	0.02159821	-	(0.00220424)	0.0186269	-	-	-	-	-	-	0.00005360	-
	DISTSEC	0.02207889	0.00000412	0.01913929	-	-	0.00314282	-	-	(0.00049825)	-	-	-	-	-	-	-	0.00009092	-
	ENERGY	0.35290781	0.00000317	0.13533823	0.00150967	0.00018405	0.02448882	0.04352107	0.00365558	(0.00720404)	0.05437365	0.09636499	-	-	-	-	-	0.00073563	-
	CUSTOMER	0.11889493	0.00002405	0.10988726	0.00088517	0.00063489	0.00076346	0.00190220	0.00072675	-	(0.00004068)	0.00045494	0.00015541	-	-	-	-	0.00350149	-
FORF_DISC_FXNL	TOTAL	1.00000000	0.00010530	0.49774998	0.00571055	0.00118925	0.07268945	0.13204632	0.00871798	-	(0.01735771)	0.13120736	0.16241781	-	-	-	-	0.00462370	-
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_FXNL TOTAL		1.00000000	0.33903126	0.42234211	0.00229503	-	0.16555973	0.03262309	-	-	-	-	-	-	0.03757470	0.00057408	-	-	-
RSALE	PRODUCTION	0.41036084	0.19208255	0.05459248	0.00066639	0.00001623	0.02470289	0.00734285	0.00050706	0.00021774	0.00139826	0.01586700	0.09070299	0.01391348	0.00715234	0.00016543	0.00012367	0.00064894	0.00017055
	BULKTRAN	(0.02656941)	(0.02508635)	0.00171976	0.00010303	0.00000622	0.00320213	0.00131935	0.00002119	(0.00037647)	0.00004361	0.00155517	(0.00868637)	(0.00195578)	0.000136247	0.00002299	0.00002171	0.00009357	0.00003436
	SUBTRAN	(0.00946139)	(0.00905971)	0.00063284	0.00003748	0.00000292	0.00122248	0.00050031	0.00001033	-	0.00001555	0.00058675	(0.00398504)	-	0.00053153	0.00000870	0.00000781	0.00001949	0.00000718
	DISTPRI	0.08327170	0.04368678	0.01772296	0.00025505	-	0.00947032	0.00300181	-	-	0.00043351	0.00582324	-	-	0.00299750	0.00006364	0.00004983	0.00016874	0.00004833
	DISTSEC	0.02796557	0.01769955	0.00615530	-	-	0.00274501	-	-	-	0.00009799	-	-	-	0.00088880	-	0.0001401	0.00028621	0.00008129
	ENERGY	0.36122943	0.12950282	0.04307537	0.00048352	0.00001261	0.02138916	0.00064873	0.00045409	0.00037138	0.00141682	0.01696599	0.11410938	0.01829877	0.00592019	0.00013791	0.00013640	0.00231574	0.00059057
	CUSTOMER	0.15320327	0.10324690	0.03497485	0.00028350	0.00004349	0.00066682	0.00026438	0.00009028	(0.00007066)	0.00001495	0.00018403	0.00004204	0.00025838	0.00000325	0.00001505	0.01102257	0.0002845	0.00202845
	TOTAL	1.00000000	0.45206993	0.15842356	0.00182897	0.00008146	0.06348881	0.01847742	0.00108293	0.00041199	0.00341373	0.04094009	0.19232499	0.03029852	0.01914119	0.00040193	0.00036848	0.01455526	0.00296073
WEATHER_FXNL	PRODUCTION	0.38232067	0.14405291	0.14553836	0.00083620	-	0.06465239	0.01296427	-	-	-	-	-	-	0.01440024	0.00023629	-	-	-
	BULKTRAN	(0.00065370)	(0.01881359)	0.00458471	0.00012928	-	0.00835020	0.00232940	-	-	-	-	-	-	0.00273345	0.00003284	-	-	-
	SUBTRAN	0.00006679	(0.00679436)	0.00168709	0.00004703	-	0.00318787	0.0008833											

**Kentucky Power Company**  
**Proposed Revenue Allocation**  
**Twelve Months Ended May 31, 2025**

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Proposed Revenue Allocation					
					Income Increase (6)	Income (7)	ROR % (8)	Revenue Increase (9)	Sales Revenue (10)	Percent Increase (11)
RS	270,140,939	1,077,256,125	22,090,840	2.05	24,805,537	46,896,377	4.35	33,202,037	303,342,976	12.29
GS	95,580,647	272,717,418	23,604,040	8.66	9,043,474	32,647,514	11.97	12,104,626	107,685,273	12.66
PS	11,592,675	23,703,542	3,975,944	16.77	1,104,835	5,080,779	21.43	1,478,814	13,071,489	12.76
LGS	49,578,570	106,700,748	14,960,568	14.02	4,695,716	19,656,284	18.42	6,285,183	55,863,753	12.68
LGS	61,171,245	130,404,290	18,936,512	14.52	5,800,551	24,737,063	18.97	7,763,997	68,935,241	12.69
IGS	159,168,054	359,805,237	16,256,701	4.52	15,583,984	31,840,685	8.85	20,859,053	180,027,107	13.11
MW	221,665	423,743	69,309	16.36	20,787	90,096	21.26	27,823	249,488	12.55
OL	8,705,501	27,207,476	3,831,282	14.08	817,196	4,648,478	17.09	1,093,811	9,799,312	12.56
SL	1,781,053	4,445,022	781,581	17.58	163,125	944,706	21.25	218,342	1,999,395	12.26
Total	596,769,104	1,872,259,310	85,570,264	4.57	56,234,654	141,804,919	7.57	75,269,688	672,038,792	12.61

Gross Rev Conversion Factor:

1.33849

**Kentucky Power Company  
Current Equalized Results  
Twelve Months Ended May 31, 2025**

<u>Current Class</u> (1)	<u>Current Revenue</u> (2)	<u>Rate Base</u> (3)	<u>Current Income</u> (4)	<u>Current ROR %</u> (5)	<u>Current Equalized Rate of Return</u>							<u>Relative ROR</u>
					<u>Percent Increase</u> (6)	<u>Revenue Increase</u> (7)	<u>Income Increase</u> (8)	<u>Income</u> (9)	<u>ROR %</u> (10)	<u>Sales Revenue</u> (11)	<u>Current Subsidy</u> (12)=(11)-(2)	
RS	270,140,939	1,077,256,125	22,090,840	2.05	13.45	36,332,555	27,144,376	49,235,216	4.57	306,473,494	36,332,555	0.45
GS	95,580,647	272,717,418	23,604,040	8.66	-15.60	(14,910,392)	(11,139,687)	12,464,353	4.57	80,670,255	(14,910,392)	1.89
LGS	61,171,245	130,404,290	18,936,512	14.52	-28.39	(17,368,923)	(12,976,478)	5,960,034	4.57	43,802,322	(17,368,923)	3.18
IGS	159,168,054	359,805,237	16,256,701	4.52	0.16	251,554	187,938	16,444,639	4.57	159,419,608	251,554	0.99
MW	221,665	423,743	69,309	16.36	-30.16	(66,847)	(49,942)	19,367	4.57	154,818	(66,847)	3.58
OL	8,705,501	27,207,476	3,831,282	14.08	-39.79	(3,463,731)	(2,587,784)	1,243,498	4.57	5,241,770	(3,463,731)	3.08
SL	1,781,053	4,445,022	781,581	17.58	-43.47	(774,216)	(578,424)	203,157	4.57	1,006,837	(774,216)	3.85
Total	596,769,104	1,872,259,310	85,570,264	4.57	0.00	0	0	85,570,264	4.57	596,769,104	0	1.00

Gross Rev Conversion Factor: 1.338493

Kentucky Power Company  
Proposed Revenue Allocation  
Twelve Months Ended May 31, 2025

Current Class (1)	Current Revenue (2)	Rate Base (3)	Current Income (4)	Current ROR % (5)	Equalized Rate of Return					100% of Current Subsidy (12)	Base Proposed Increase (13)=(7)-(12)	Base Percent Increase (14)	Base Mitigation Change Needed (15)	Mitigated Proposed Increase (16)=(13)+(15)	Mitigated Percent Increase (17)	Total Current Revenue	Mitigated Total Percent Increase	Generation Rider Increase	Mitigated Total Impact	
					Percent Increase (6)	Revenue Increase (7)	Income Increase (8)	Income (9)	ROR % (10)											Sales Revenue (11)
RS	270,140,939	1,077,256,125	22,090,840	2.05	29.48	79,641,050	59,500,539	81,591,379	7.57	349,781,989	36,332,555	43,308,495	16.03	(10,106,458)	33,202,037	12.29	286,735,722	11.6%	3.4%	15.0%
GS	95,580,647	272,717,418	23,604,040	8.66	-4.13	(3,946,443)	(2,948,423)	20,655,617	7.57	91,634,204	(14,910,392)	10,963,949	11.47	1,140,677	12,104,626	12.66	105,637,778	11.5%	2.4%	13.8%
LGS	61,171,245	130,404,290	18,936,512	14.52	-19.82	(12,126,332)	(9,059,691)	9,876,821	7.57	49,044,913	(17,368,923)	5,242,591	8.57	2,521,406	7,763,997	12.69	67,756,852	11.5%	2.5%	13.9%
IGS	159,168,054	359,805,237	16,256,701	4.52	9.25	14,716,660	10,994,948	27,251,649	7.57	173,884,714	251,554	14,465,106	9.09	6,393,947	20,859,053	13.11	182,038,170	11.5%	3.4%	14.9%
MW	221,665	423,743	69,309	16.36	-22.47	(49,812)	(37,215)	32,094	7.57	171,853	(66,847)	17,035	7.69	10,788	27,823	12.55	242,812	11.5%	2.0%	13.5%
OL	8,705,501	27,207,476	3,831,282	14.08	-27.22	(2,369,920)	(1,770,588)	2,060,694	7.57	6,335,581	(3,463,731)	1,093,811	12.56	0	1,093,811	12.56	9,318,114	11.7%	0.3%	12.0%
SL	1,781,053	4,445,022	781,581	17.58	-33.44	(595,515)	(444,915)	336,666	7.57	1,185,538	(774,216)	178,701	10.03	39,641	218,342	12.26	1,905,482	11.5%	0.3%	11.8%
Total	596,769,104	1,872,259,310	85,570,264	4.57	12.61	75,269,688	56,234,656	141,804,920 141,804,920	7.57	672,038,792	0	75,269,688	12.61	0	75,269,688	12.61	653,634,930	11.5%	3.1%	14.6%

Gross Rev Conversion Factor: 1.338493

**Class- Cost-of-Service Study Allocation Methodology**

<b>Cost of Service Component</b>	<b>Allocation</b>
<b>Production Plant including Generator Step-Up Transformers</b>	Classified as demand-related and allocated to the retail classes based on their average contribution to the Company's 12 coincident peaks (CPs). The CPs used in the allocation of Production Plant investment were the 12 monthly internal peak demands for the year ended May 31, 2025.
<b>Transmission Plant</b>	Classified as demand-related and allocated to the retail classes based on their average contribution to the Company's 12 coincident peaks (CPs) on the transmission facilities.
<b>Distribution Plant</b>	Classified as demand or customer related and allocated to the customer classes using factors based on demand levels or number of customers. Distribution Plant accounts 360 through 373 were classified as follows:
Accounts 360-63 – Distribution Land and Land Rights; Structures and Improvements; Station Equipment; Storage Battery Equipment	Allocated to the distribution customer classes based on the class contribution to the average of the Company's 12 monthly peak demands on the primary distribution system.
Accounts 364-68 – Poles, Towers and Fixtures; Overhead Conductors and Devices; Underground Conduit; Underground Conductors and Devices; Line Transformers	Classified as demand and customer-related per the results of the zero-intercept study. The demand portion was split into primary and secondary voltage functions. The demand-related primary portions were allocated using the average of 12 monthly CP demands on the distribution system. The demand-related secondary components were allocated based on a combination of each class's 12-month maximum demand and the summation of individual customers' annual maximum demands. This process reflects the fact that some secondary facilities serve only one customer, while others serve two or more customers.
Account 369 – Services	Classified as customer-related and allocated using the average number of secondary customers served.
Account 370 – Meters	Allocated using the average number of customers weighted by a factor which considers the weighted average cost of various metering installations.
Account 371 – Installations on Customer Premises	Directly assigned to the outdoor lighting class.
Account 373 – Street lighting and signal systems	Directly assigned to the street lighting class.

<b>Cost of Service Component</b>	<b>Allocation</b>
<b>General &amp; Intangible Plant</b>	Allocated based on payroll labor expense.
<b>Depreciation Reserve</b>	The functionalized components of Depreciation and Amortization were allocated on the corresponding functional Electric Plant-in-Service allocators excluding land and land rights.
<b>Working Capital</b>	Working Capital was divided into cash, material and supplies and prepayments.
Working Capital - Cash	Allocated on O&M expense less purchased power and fuel.
Working Capital – Materials and Supplies	Split between Fuel Stock, Production, Emissions and Transmission and Distribution. Fuel stock and emissions were allocated on loss adjusted energy. Production was allocated using the production demand allocation factor. The Transmission and Distribution portion was allocated based on the transmission and distribution electric plant-in-service.
Working Capital – Prepayments	Allocated by gross utility plant.
<b>Plant Held for Future Use</b>	Allocated by the corresponding functional Electric Plant-in-Service allocators. Limited to a distribution component.
<b>Construction Work in Progress</b>	Allocated by the corresponding functional Electric Plant-in-Service allocators.
<b>Accumulated Deferred Federal Income tax</b>	Allocated by gross utility plant.
<b>Customer Advances</b>	Allocated by transmission and distribution Electric Plant-in-Service.
<b>Customer Deposits</b>	Directly assigned based on accounting records.
<b>Revenues</b>	Sales Revenue was directly assigned to each class. Energy-related System Sales Revenue was allocated on the basis of loss adjusted kWh sales.
Account 450 -451 – Forfeited Discounts; Miscellaneous Service Revenue	Directly assigned based on an analysis of accounting records.



<b>Cost of Service Component</b>	<b>Allocation</b>
Accounts 454, 456 – Rent from Electric Property; Other Electric Revenue	Functionalized in the jurisdictional cost-of-service study and allocated by the corresponding functional allocators.
<b>Production O&amp;M</b>	Allocated using the production plant demand allocator. The energy-related Production expenses were allocated using loss-adjusted energy. Supervision and Engineering accounts for both O&M were allocated based on functional labor expense.
<b>Transmission O&amp;M</b>	Broken down into two pieces: expenses incurred through PJM as a Load Serving Entity and the traditional transmission cost-of-service expenses recorded in FERC accounts 560-575. Most transmission expenses were allocated by the transmission demand allocation factor. Supervision and Engineering was allocated based on labor expense. PJM LSE were allocated based on production demand.
<b>Distribution O&amp;M</b>	Functionalized and classified according to the associated distribution plant accounts and allocated accordingly.
Account 581-582 – Load Dispatching; Station Equipment Expense	Allocated based on the distribution demand allocation factor.
Account 583 – Overhead Line Expense	Allocated based on the associated distribution plant (Account 365 – Overhead Lines).
Account 584 – Underground Line Expense	Allocated based on Account 366 – Underground Conduits, and Account 367 – Underground Lines.
Account 585 – Street Lighting Operation Expense	Classified as customer-related and directly assigned to the Street Lighting class.
Account 586 – Meter Expense	Classified as customer-related and allocated in the same manner as Account 370 – Meter Plant.
Account 587 – Customer Installation Expense	Classified as customer-related and allocated based on primary customers.
Accounts 588-89 – Miscellaneous Expense; Rents	Allocated on total distribution plant and classified accordingly.

<b>Cost of Service Component</b>	<b>Allocation</b>
Account 580 – Operation Supervision and Engineering	Classified and allocated using the allocated subtotal of Accounts 581 through 589.
Account 591-92 – Maintenance of Structures; Station Equipment	Allocated on total distribution plant and classified accordingly.
Accounts 593-95 – Maintenance of Overhead Lines, Underground Lines, Line Transformers	Classified according to the associated distribution plant accounts and allocated accordingly.
Account 596 – Maintenance of Street Lighting	Classified as customer-related and directly assigned to the Street Lighting class.
Account 597 – Maintenance of Meters	Classified as customer-related and allocated in the same manner as Account 370 – Meters.
Account 598 – Maintenance of Miscellaneous Distribution Plant	Classified as customer-related and directly assigned to the Outdoor Lighting class.
Account 590 – Maintenance Supervision and Engineering	Classified and allocated based on the sum of the allocated O&M expense Accounts 591 through 598.
<b>Customer Accounting</b>	
Account 902 – Meter Reading Expense	Allocated to those classes with meter installations based on the average number of customers weighted to reflect varying levels of difficulty in meter reading.
Account 903 – Customer Records and Collection Expense	Divided into two categories of cost: Call Center and Other. Call center costs were first divided into residential and other based on number of calls. Then Other was allocated to the remaining non-residential classes based on the number of customers in each respective class.
Account 904 – Uncollectibles	Allocated based on the number of customers.

<b>Cost of Service Component</b>	<b>Allocation</b>
Accounts 901, 905 – Supervision; Miscellaneous Customer Accounts Expenses	Allocated based on the sum of the allocated Accounts 902, 903, and 904.
<b>Customer Services and Sales Expenses (Accounts 907-916)</b>	Classified as customer-related and allocated to all classes based on the number of customers.
<b>Administrative &amp; General Expense</b>	<p>A&amp;G expenses, other than Property Insurance and Rate Case Expense, were classified, and allocated using Total O&amp;M labor.</p> <p>Property Insurance was allocated based on gross utility plant.</p> <p>Rate Case Expense was allocated based on sales revenue.</p>
<b>Depreciation and Amortization Expense</b>	The functionalized components of Depreciation and amortization expense were allocated using the corresponding plant items excluding land and land rights.
<b>Various Tax Expenses</b>	Individual Other Tax items were classified and allocated using the appropriate plant, revenue, or labor item. Interest Expense was allocated on rate base and individual Schedule M items were allocated using appropriate allocators. Current FIT and State Income Tax were calculated separately for each class. Deferred Federal Income Tax was allocated using the appropriate allocation factors.
<b>Other Remaining Expense Items</b>	<p>Gain on Disposition of Utility Plant was allocated based on distribution plant. A/R Factoring was allocated based on gross utility plant.</p> <p>Gain/Loss on Disposition of Allowances was allocated using loss adjusted energy. Accretion was allocated on production demand.</p> <p>Interest on Customer Deposits was allocated to classes on the same basis as Customer Deposits. Other Interest expense was allocated on gross utility plant.</p>
<b>Allowance for Funds Used During Construction Offset</b>	The production component was classified as demand related and allocated to the retail classes based on their average contribution to the Company's 12 coincident peaks (CPs). The transmission and distribution components were allocated using the corresponding Electric Plant-in-Service allocators. The general plant component was allocated using labor.

**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 Certain Regulatory And Accounting    )  
Treatments; and (4) All Other Required Approvals     )  
And Relief                                                        )

Case No. 2025-00257

**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. 2025-00257**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT MMS-1	Base Rate Revenue Target Summary & Rate Design
EXHIBIT MMS-2	Economic Development Rider Customer Analysis
EXHIBIT MMS-3	Special Contract Analysis

**DIRECT TESTIMONY OF  
MICHAEL M. SPAETH ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.     My name is Michael M. Spaeth, and I am employed by American Electric Power Service  
3           Corporation (“AEPSC”) as a Regulatory Pricing & Analysis Manager. My business  
4           address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary  
5           of American Electric Power Company, Inc. (“AEP”), the parent Company of Kentucky  
6           Power Company (the “Company” or “Kentucky Power”).

**II. BACKGROUND**

7   **Q.     PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
8           **BUSINESS EXPERIENCES.**

9   A.     I graduated from The Ohio State University with a Bachelor of Science degree in City &  
10          Regional Planning. In 2013, I accepted a position at AEPSC in Regulated Pricing and  
11          Analysis, where my responsibilities included preparation of cost-of-service studies, rate  
12          design and tariff provisions for the AEP operating companies. In 2017, I accepted a  
13          position with NiSource Inc., a regulated natural gas and electric utility, as a Project  
14          Analyst – Planning, where I was responsible for regulatory case management in support of  
15          long and short-term natural gas forecasting plans, reporting to various state and federal  
16          regulatory commissions, and the calculation of rates. In 2019, I returned to AEPSC as a  
17          Regulatory Consultant Senior, where my responsibilities include preparation of

1 cost-of-service studies, rate design and tariff provisions for the AEP operating companies.

2 I was promoted to my current position in 2022.

3 **Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?**

4 A. My responsibilities include the oversight of cost-of-service analyses, rate design, and  
5 special contracts for the AEP System operating companies. I provide these services for  
6 Kentucky Power.

7 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
8 **PROCEEDINGS?**

9 A. Yes. I have presented testimony on behalf of AEP operating companies before the Virginia,  
10 West Virginia, Kentucky, Texas, and Indiana state regulatory commissions.

### **III. PURPOSE OF TESTIMONY**

11 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
12 **PROCEEDING?**

13 A. The purpose of my Direct Testimony is to:

- 14 • Provide an overview of how the Company's base rates relate to the surcharges  
15 and riders it utilizes;
- 16 • Describe the Company's proposed rate design, including the structural changes  
17 to the residential service charge, residential declining energy block, and  
18 COGEN/SPP capacity credit calculation;
- 19 • Support certain operation and maintenance expense and operating revenue  
20 adjustments detailed in Section V, Exhibit 2; and
- 21 • Support the marginal cost-of-service analysis related to the test year operation  
22 of the Company's Economic Development Rider and its special contracts.

1    **Q.    ARE YOU SPONSORING ANY EXHIBITS?**

2    A.    Yes. I am sponsoring the following exhibits:

- 3                    •    Exhibit MMS-1 – Base Rate Revenue Target Summary & Rate Design
- 4                    •    Exhibit MMS-2 – Economic Development Rider Customer Analysis
- 5                    •    Exhibit MMS-3 – Special Contract Analysis

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

8    A.    Yes.

**IV. BASE RATE COST-OF-SERVICE OVERVIEW**

9    **Q.    CAN YOU GENERALLY DESCRIBE THE MECHANISMS THROUGH WHICH**  
10    **KENTUCKY POWER CHARGES ITS CUSTOMERS FOR THE ELECTRIC**  
11    **SERVICE IT PROVIDES?**

12   A.    Yes. Kentucky Power charges its customers for electric service through two mechanisms:  
13        (1) base rates and (2) surcharges and riders. Through base rates, the Company primarily  
14        recovers its going level operating expenses and a return on and of the capital investments  
15        it has prudently made to provide safe and reliable electric service to its customers. The  
16        Company also recovers through surcharges and riders certain costs that are volatile or  
17        otherwise better suited for recovery through mechanisms other than base rates.

18   **Q.    HOW DOES THE INTERRELATION BETWEEN BASE RATES AND THE**  
19    **COMPANY'S SURCHARGES AFFECT THE COST-OF-SERVICE STUDY**  
20    **PERFORMED IN THIS CASE?**

21   A.    Kentucky Power's test year revenues and operating expenses included revenues and  
22        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, either by remaining in base rates or removal, 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:

- Demand-Side Management (“D.S.M.”) Adjustment Clause;
- Residential Energy Assistance (“R.E.A.”);
- Kentucky Economic Development Surcharge (“K.E.D.S.”);
- Purchased Power Adjustment (“P.P.A.”);
- System Sales Clause (“S.S.C.”);
- Fuel Adjustment Clause (“F.A.C.”);
- Environmental Surcharge (Mitchell FGD portion); and
- Federal Tax Cut Tariff (“F.T.C.”).

Each of these surcharges recovers specifically-identified costs that are separate from the Company’s base rate requirements.

- D.S.M. Adjustment Clause: through the D.S.M. Adjustment Clause, the Company recovers the program costs and lost revenues associated with the Company’s Public Service Commission of Kentucky (“Commission”)-approved demand side management and energy efficiency programs.

- 1           • Residential Energy Assistance: the R.E.A. surcharge is a fixed charge levied on  
2           each residential account and matched on a one-to-two dollar basis by the  
3           Company to provide financial assistance to low-income residential customers.
- 4           • Kentucky Economic Development Surcharge: K.E.D.S. is a fixed charge levied  
5           on each account and matched on a dollar-for-dollar basis by the Company, to  
6           support economic development in the Company's service territory.
- 7           • Fuel Adjustment Clause: the F.A.C. mechanism collects from, or credits to,  
8           customers the difference between actual fuel costs and the fuel rate embedded  
9           in base energy rates for fuel on a monthly basis. During the test year, there were  
10          base fuel rates for two periods, \$0.02610 \$/kWh collected through December  
11          30, 2024, and \$0.03880 \$/kWh collected from December 31, 2024 through May  
12          31, 2025.
- 13          • Purchased Power Adjustment: the P.P.A. collects certain purchase power costs  
14          not recoverable through the fuel adjustment clause; capacity charges and  
15          C.S.-I.R.P. ("Contract Service-Interruptible Power"), D.R.S. ("Demand  
16          Response Service"), and V.C.S. ("Voluntary Curtailment Service") credits paid  
17          to interruptible customers; and costs associated with certain previously-  
18          approved Rockport-related items.
- 19          • System Sales Clause: the S.S.C. is the Company's tracking mechanism for off  
20          system sales margins achieved versus the credit amount embedded in base rates.  
21          The test year S.S.C. retail revenues and deferral were removed from the  
22          proposed base rate cost-of-service; adjusted off system sales margins were

1 included in the base rate cost-of-service as I discuss later in my Direct  
2 Testimony.

- 3 • Environmental Surcharge (Mitchell FGD Portion): generally, test year  
4 environmental surcharge costs are included in base rates as part of a base rate  
5 cost-of-service. However, in accordance with the Commission-approved  
6 settlement agreement in Case No. 2012-00578, the full cost-of-service  
7 associated with the Mitchell plant flue gas desulfurization (“FGD”) system  
8 remains in the environmental surcharge for recovery purposes.
- 9 • Federal Tax Cut Tariff: this rider provides a rate credit to customers related to  
10 the amortization of excess accumulated deferred federal income taxes  
11 (“ADIT”) related to the Tax Cuts and Jobs Act of 2017 and the ADIT benefit  
12 related to non-Decommissioning Rider Regulatory Assets approved for  
13 securitization.

14 **Q. CONVERSELY, ARE THERE ANY SURCHARGES WHOSE REVENUES AND**  
15 **EXPENSES ARE INCLUDED IN BASE RATES?**

16 A. Yes. The Company included the revenues and expenses associated with the non-Mitchell  
17 FGD portion of the test year environmental surcharge in its proposed base rate  
18 cost-of-service.

19 **Q. ARE ALL OF THE TEST YEAR ENVIRONMENTAL COMPLIANCE COSTS**  
20 **INCLUDED IN BASE RATES?**

21 A. No. As noted above, all Mitchell FGD costs are recovered exclusively through the  
22 environmental surcharge (as opposed to just the variance from the prior year’s costs).

1 **Q. WHY WERE A PORTION OF THE ENVIRONMENTAL SURCHARGE**  
2 **REVENUES INCLUDED IN BASE RATES?**

3 A. The Company incurred costs during the test year associated with projects included in the  
4 Company's approved environmental compliance plan. Through the environmental  
5 surcharge, the Company recovers from or credits to customers the costs of its  
6 environmental projects that exceed or are below the corresponding monthly amounts  
7 included in base rates. The Company's test year non-Mitchell FGD environmental  
8 compliance costs and non-Mitchell FGD environmental surcharge revenues are included  
9 in base rates and serve as the monthly baselines against which actual costs are compared.  
10 Company Witness Cullop discusses in detail the methodology behind this adjustment.

11 **Q. WHY DOES THE COMPANY INCLUDE OFF SYSTEM SALES MARGINS**  
12 **FROM THE SYSTEM SALES CLAUSE IN BASE RATES?**

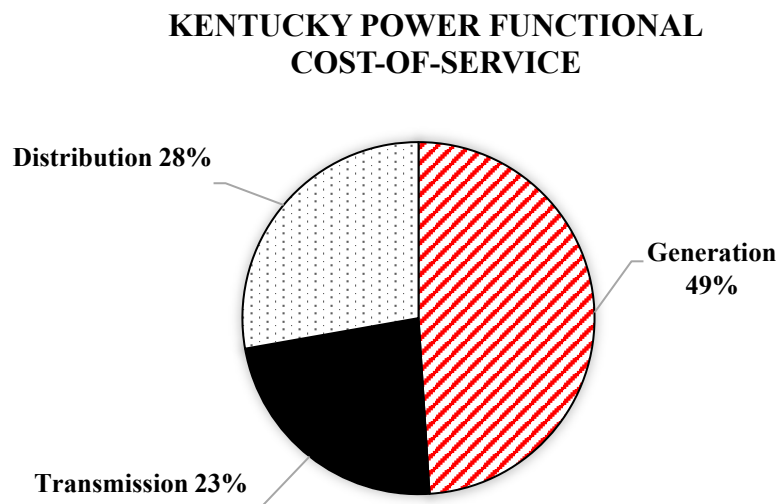
13 A. Through the S.S.C., the Company shares with customers the difference between the  
14 embedded base rate credit for off system sales margins and the actual off system sales  
15 margins realized. The Company included an adjusted level of off system sales margins in  
16 the base rate cost-of-service because the Company is proposing to reset the embedded base  
17 rate credit to the test year level of off system sales margins. I will discuss the impact of this  
18 reset in more detail later in my Direct Testimony.

## **V. RATE DESIGN**

**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 costs associated with the Company's basic functions of generation, transmission and distribution service. The relative portions of the cost-of-service for each basic function is as follows:

**Figure MMS-1**



The generation function comprises the largest portion 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 39% of the Company's adjusted test year usage (and associated billing units) was for customers taking service at voltage levels above distribution. Therefore, 28% of the Company's cost-of-service (distribution

function) is paid by distribution level customers that make up about 61% of adjusted test year billing units.

**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 Coon 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 whether the Company needed to moderate the full-cost price changes to mitigate rate impacts on groups of customers. The proposed mitigated 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 proposing two changes for the residential class in rate design: a two-tiered basic service charge and a two-block declining energy charge. The Company is also

1 updating the capacity credit calculation method for customers taking service under Tariff  
2 COGEN/SPP, in accordance with the Commission's January 19, 2024 Order in Case No.  
3 2023-00159.

**Residential Service Rate Design**

4 **Q. PLEASE DESCRIBE THE RESIDENTIAL RATE DESIGN STRUCTURE THE**  
5 **COMPANY IS PROPOSING IN THIS PROCEEDING.**

6 A. The Company is proposing to modify the basic service charge to a two-tiered structure  
7 where customers who consume between 0–2,000 kWh in a month will be charged the  
8 Tier 1 charge of \$26.00 per month and customers who consume greater than 2,000 kWh in  
9 a month will be charged the Tier 2 charge of \$40.00 per month. It is important to note that  
10 from a billing perspective, the tiered basic service charge is either Tier 1 or 2; customers  
11 will only be charged at *either* Tier 1 or 2 depending on their total energy usage at the end  
12 of a billing month. Coupled with the updated basic service charge, the Company is also  
13 proposing a declining block energy rate where all customers are charged \$0.15750 per kWh  
14 for the first 600 kWh in a month and \$0.12606 for all usage in excess of 600 kWh.

15 **Q. WHAT IS THE RATIONALE FOR THE RESIDENTIAL CHANGES?**

16 A. The Company is proposing to introduce the tiered basic service charge for residential  
17 customers to more accurately reflect the actual fixed cost of providing service to those  
18 customers while also mitigating bill impacts to lower-usage customers. The fixed monthly  
19 cost associated with connecting a residential customer to the distribution system (and  
20 maintaining that customer's connection) is \$46.19, which is greater than both tiers of the  
21 Company's proposed basic service charges.

1           The rate structures for customer classes that employ demand charges are better  
2 aligned with cost causation principles than those that do not because fixed costs are  
3 generally recovered through a demand charge. However, the standard residential tariff does  
4 not include a separate demand charge; therefore, most fixed distribution costs are recovered  
5 through the energy charge. These fixed distribution costs, or at least a larger portion of  
6 them, should be recovered in the basic service charge since they do not vary with usage  
7 and are instead solely the costs associated with connecting a customer to the distribution  
8 system and maintaining that connection. The current basic service charge is too low relative  
9 to the fixed cost of providing electric service creating intra-class subsidies between  
10 residential customers. Because of these intra-class subsidies, the current basic service  
11 charge disadvantages higher usage customers, including electric heating and lower income  
12 customers.

13 **Q. DID THE BASIC SERVICE CHARGE INCREASE IN THE COMPANY'S LAST**  
14 **BASE RATE CASE ELIMINATE THE INTRA-CLASS SUBSIDY?**

15 A. No. The basic service charge increase in the last base rate case from \$17.50 to \$20.00 per  
16 month helped to reduce the intra-class subsidy being paid by higher use customers but did  
17 not eliminate it. As can be seen in Exhibit MMS-1, the total proposed base rate revenue  
18 target for the residential class is \$308.1 million of which the energy portion is \$81.3  
19 million. The \$226.8 million balance is comprised of demand- and customer-related costs.  
20 Demand- and customer-related costs are commonly referred to as "fixed costs" as they do  
21 not vary with kWh usage levels.

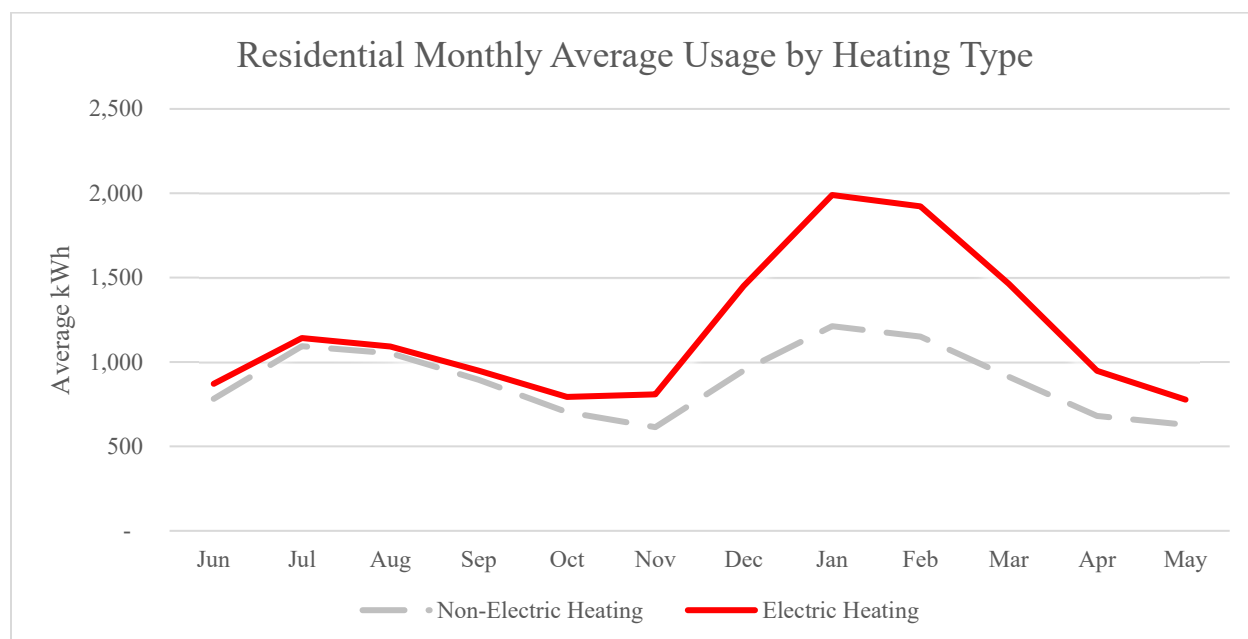
22           The current residential base rate design, however, only recovers \$31.3 million  
23 (1,564,142 bills x \$20.00 service charge) of fixed costs from non-kWh charges with the



1 other \$195.5 million of fixed costs being collected through kWh rates. This creates a large  
2 intra-class subsidy paid by above average usage customers, like electric heating customers,  
3 to below average usage customers. Based on test year analysis approximately 84% of the  
4 Company's residential customers fall in the Tier 1 basic service charge and the proposed  
5 \$6 increase in the basic service charge will reduce the existing intra-class subsidy by  
6 shifting \$7.9 million to fixed recovery (1,314,461 bills x \$6), which is a reasonable and  
7 gradual step in the right direction.

8 **Q. WHAT IS THE PRIMARY SOURCE OF VOLATILITY IN RESIDENTIAL**  
9 **CUSTOMERS' BILLS?**

10 A. Bill volatility is largely driven by the pronounced seasonal swings in electricity usage  
11 across the Company's customer base. The widespread use of electric heating, particularly  
12 heat pumps, results in consumption spikes during cold winter months. Approximately 63%  
13 of residential customers rely on electric heating, while the remaining 37% use non-electric  
14 sources. Figure MMS-2 below highlights the month-to-month variation during the test year  
15 in average kWh usage between these two groups.

**Figure MMS-2**

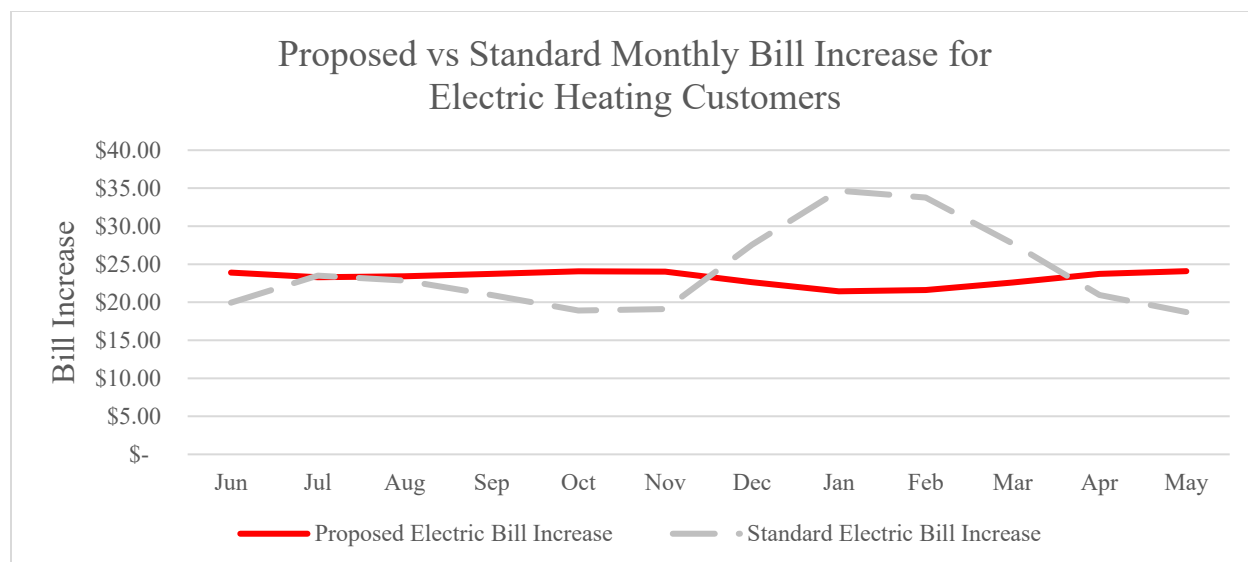
Electric and non-electric heating customers use similar amounts of energy during the summer months, but their usage begins to diverge in November when temperatures typically begin to fall. In January, the peak usage month, the difference reaches a striking 870 kWh. For electric heating customers, average usage more than doubles from a low of 778 kWh in May to a high of 1,990 kWh in January. This sharp seasonal increase leads to inevitable and substantial bill volatility under a conventional rate design that relies on a single basic service and a single energy charge exclusively.

**Q. WILL THE RESIDENTIAL RATE REDESIGN ALSO MITIGATE MONTHLY BILL VOLATILITY?**

A. Yes. Generally, because of the highly seasonal nature of customers' energy usage, redistributing revenue recovery out from the volumetric energy charge and into the basic service charge will help ease bill volatility. This is especially true for the Company's electric heating customers, who tend to experience high-usage months in the winter to heat

their homes. Figure MMS-3 below depicts the resultant monthly bill increase for the average electric heating customer arising from the Company's proposed rate design as compared to a standard single rate design consisting of a \$28.16 basic service charge and a flat \$0.13965 energy rate.<sup>1</sup>

**Figure MMS-3**



The proposed rate design minimizes additional bill volatility by evenly distributing the proposed cost increases throughout the year. Unlike a standard single rate design, which results in a bill spike in January, the proposed rate design offers a smoother and more predictable bill, making it more favorable for higher-usage customers.

**Q. HOW WERE THE NEW BASIC SERVICE CHARGES DETERMINED?**

A. The Company is proposing a gradual, but material increase in the basic service charge. The current residential customer charge is \$20. The \$6 increase to \$26 for the lower block, was calculated to help limit bill impacts that result from subsidy reductions on the lower use

<sup>1</sup> The calculated standard rates of a \$28.16 basic service charge and \$0.13965 energy rate are based upon the proposed rate design percentage of full cost recovery and are not indicative of what the Company would calculate had it not offered its proposed rate design.

1 residential customers that are currently enjoying the intra-class subsidy being paid by  
2 higher use customers. Customers who use more than 2,000 kWh in a month pay only the  
3 Tier 2, \$40 basic service charge, which collects the remaining share of customer-related  
4 costs that the basic service charges must recover. The difference between the two service  
5 charges was carefully calibrated so that a customer using just over 2,000 kWh experiences  
6 no more than a 15% increase, consistent with the residential class average estimated rate  
7 impact.

8 **Q. ARE EITHER OF THE PROPOSED RESIDENTIAL BASIC SERVICE CHARGES**  
9 **OF \$26 OR \$40 PER MONTH APPROACHING FULL COST?**

10 A. Yes. The full fixed cost to provide and maintain service to residential customers is \$46.19.  
11 As the Company does not currently recover the full-cost basic service charge, remaining  
12 customer-related costs must be recovered through the energy charge. The more  
13 customer-related costs that are recovered through the basic service charge, the less must be  
14 recovered in energy rates. This approach is beneficial to higher-usage customers and aligns  
15 rates more closely to costs. A full cost basic service charge represents a 100% recovery of  
16 customer-related costs through the basic service charge. In this case, the Company is  
17 proposing to recover 61% of customer related costs through the basic service charge, which  
18 is higher than currently recovered. This change would result in a non-blocked service  
19 charge of \$28.16, or a 41% increase from the current basic service charge. However, by  
20 blocking the service charge, this increase is mitigated to 30% for customers with usage  
21 under 2,000 kWh to only \$26. The basic service charge of \$40 for higher usage customers,  
22 those over usage 2,000 kWh, is approaching full cost but still less than the calculated unit  
23 cost per month of \$46.19. This shift marks significant progress toward full cost recovery,

1 while also helping to reduce bill impacts for lower-usage customers and winter bills  
2 overall, in line with the principle of gradualism.

3 **Q. PLEASE DESCRIBE THE RATIONALE FOR A BLOCKED ENERGY CHARGE.**

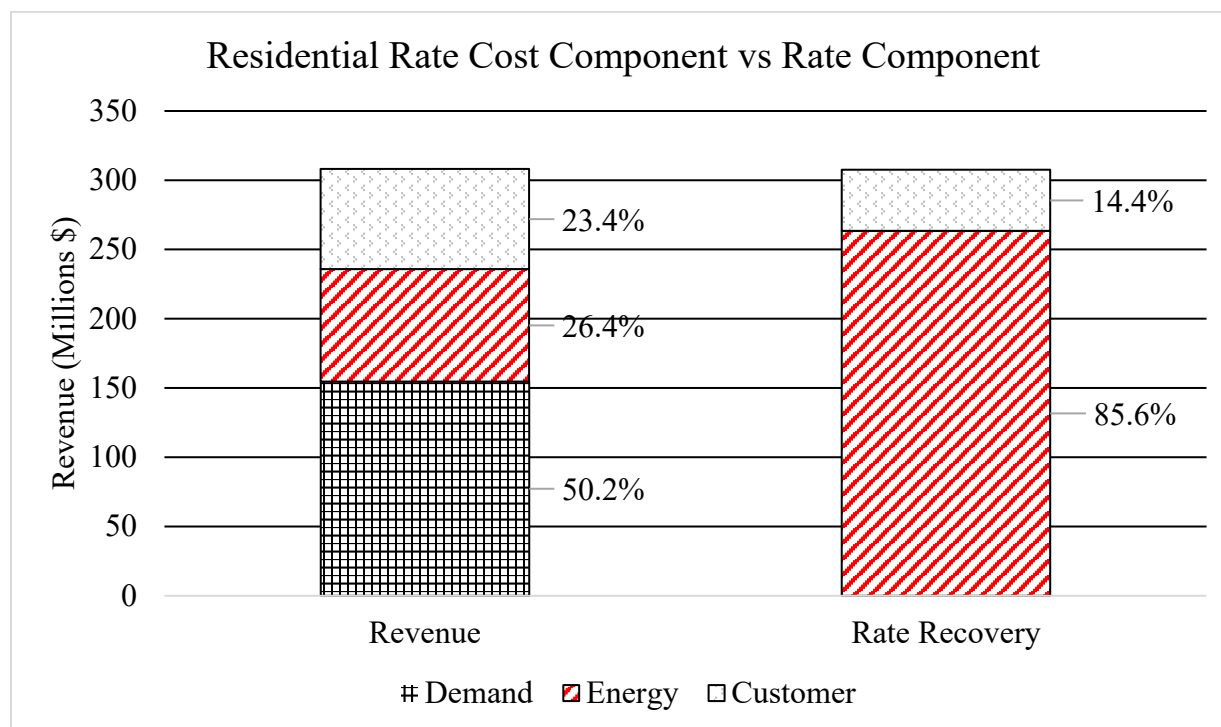
4 A. To provide winter bill relief and reduce monthly bill volatility for the Company's electric  
5 heating and lower income customers, the Company is proposing a declining, blocked  
6 energy charge to provide winter bill relief and reduce monthly bill volatility for customers  
7 who heat their homes with electricity, many of whom are lower income customers  
8 receiving bill assistance. The proposed rate for all monthly usage above 600 kWh,  
9 \$0.12606 per kWh, is more than \$0.03 lower than the block one energy rate and is lower  
10 than the energy charge currently charged to Kentucky Power customers (\$0.12785 per  
11 kWh). The higher the customer's usage is above 600 kWh, the more significantly these  
12 savings add up, offsetting the \$14 increase to the customer charge when a customer passes  
13 2,000 kWh of usage in a month. Customers with usage over 3,000 kWh per month will  
14 realize the largest bill mitigation. The Company estimates approximately 15.7% of  
15 residential customers use at least 3,000 kWh per month during winter months.

16 **Q. HOW WERE THE NEW BLOCKED ENERGY CHARGE RATES**  
17 **DETERMINED?**

18 A. The rates were designed to recover all the remaining customer-related costs in the first  
19 energy block that are not recovered through the customer basic service charge, plus a  
20 portion of the total secondary voltage distribution costs. These remaining residential costs  
21 are recovered through the volumetric energy charge in the second block. As shown in  
22 Exhibit MMS-1, the proposed revenues for Residential Service tariffs total \$308,111,016,

with \$154,582,178 classified as demand related, \$81,278,002 as Energy, and \$72,250,836 as Customer, visualized below in Figure MMS-4.

**Figure MMS-4**



As shown, 50.2% of the Company's costs required to serve the residential class are fixed, demand-related costs, as classified by the cost-of-service. Energy and customer-classified costs account for 26.4% and 23.4% of total costs, respectively. In contrast, in the proposed rates, only 14.4% of customer-related costs are recovered through the customer charge, and there is no demand-based charge. This results in the blocked energy charges having to recover fixed costs volumetrically, which disadvantages higher-usage customers.

Nevertheless, the proposed rate design moves cost recovery in the right direction, toward a more accurate recovery of customer and demand-related charges through rates, primarily driven by the increased customer charge. By recovering all the remaining

customer-related costs in the first energy block, along with a significant portion of the demand-related costs, higher usage customers benefit from a volumetric energy rate that more closely reflects the actual energy cost component.

**Q. WILL THE COMPANY'S PROPOSED RESIDENTIAL RATE STRUCTURE DETER ENERGY CONSERVATION?**

A. No. An increase in usage will still result in an increased bill. In addition to its proposal to introduce the tiered basic service charge, the energy charge is either increasing or very slightly decreasing, as compared to current rates. 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.

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.

**Q. WHAT KIND OF RATE DESIGN WOULD RESULT IN THE CLEAREST PRICE SIGNALS?**

A. The clearest price signals to customers would come from implementing a per kW demand charge to recover the remaining residential distribution system costs 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

1 include a larger portion of these connection costs through the increased basic service  
2 charge. Second, the Company incurs residential system distribution costs by sizing the  
3 distribution system to meet customer peak kW demand. These sizing costs vary by peak  
4 demand requirements, not by kWh usage or by simply connecting a customer to the system.

5 These sizing costs would ideally be collected through a demand charge; however,  
6 the Company's current residential class metering infrastructure does not provide the  
7 information necessary to institute a per kW demand charge. It may be possible for the  
8 Company to obtain this information after the full installation of the recently approved  
9 installation of advanced metering infrastructure. Under the Company's proposal, over 85%  
10 of the Company's residential customer class revenues are still being recovered through a  
11 per kWh usage charge. In the absence of a peak demand charge, the Company is proposing  
12 to move a portion of those fixed distribution costs that only vary with the number of  
13 customers connected to the system from the per kWh charge to the basic service charge.

14 **Q. IS THIS THE SAME RESIDENTIAL RATE DESIGN THAT THE COMPANY**  
15 **PROPOSED IN CASE NO. 2023-00159?**

16 **A.** No. In Case No. 2023-00159, the Company proposed an optional seasonal rate solely  
17 focused on providing targeted winter bill relief for higher-usage customers. The proposed  
18 changes to the standard residential tariff in this proceeding are not optional nor are they  
19 targeted at customers with specific usage patterns. The Company's proposed residential  
20 rate structure gradually increases fixed cost recovery through the basic service charge while  
21 also reducing intra-class subsidies within the residential class. The proposed design  
22 provides the added benefit of reducing bill volatility while including appropriate price  
23 signals to its customers.



1 **Q. DESCRIBE THE ENERGY CONSERVATION PRICE SIGNAL THAT THE**  
2 **PROPOSED RATE DESIGN SENDS TO CUSTOMERS.**

3 A. The blocked structure of the basic service charge provides an opportunity and incentive for  
4 customers to save through achievable energy conservation. In the winter months, some  
5 customers use slightly more than 2,000 kWh in a month. If a customer can reduce their  
6 usage from 2,050 kWh to 1,950 kWh, they will save over \$26. Over half of this savings  
7 (\$14) comes from crossing back below the Tier 2 customer charge threshold. This sends a  
8 clear price signal: conserve energy, save money. Similarly, for customers whose usage is  
9 approaching 2,000 kWh, they have a strong incentive to curb their usage to not cross the  
10 threshold. In this way, the blocked customer charge builds an energy-conserving incentive  
11 into rate design, without inordinately punishing extremely high-usage customers who have  
12 limited options to significantly decrease their energy usage or extremely low-usage  
13 customers who have been beneficiaries of the intra-class subsidies.

14 **Q. IN SUMMARY, DOES THE COMPANY'S PROPOSED RESIDENTIAL RATE**  
15 **DESIGN BENEFIT THE COMPANY'S ELECTRIC HEATING CUSTOMERS?**

16 A. Yes. Because electric heating customers on average use more kWh than the class average,  
17 the reduction of the intra-class subsidy being paid through the volumetric energy charge  
18 will benefit them. The proposed residential rate design supports electric heating by using a  
19 blocked basic service charge and a seasonal energy rate structure. The blocked basic  
20 service charge helps limit bill increases during lower-usage months, which benefits  
21 customers with lower or more variable usage. The blocked energy charge reduces the  
22 per-kWh cost in higher-usage months, helping to moderate seasonal bill spikes—especially  
23 for electric heating customers.

**Cogeneration Tariff – Capacity Credits**

1   **Q.   DID YOU COMPLY WITH THE COMMISSION’S DIRECTIVE IN CASE NO.**  
2       **2023-00159 WITH RESPECT TO THE CALCULATION OF THE COGEN TARIFF**  
3       **CAPACITY CREDITS?**

4   A.   Yes. The Commission made it clear that “given Kentucky Power’s current economic and  
5       financial condition, the Commission will allow Kentucky Power to utilize the Net CONE  
6       [cost of new entry] for its cogeneration capacity cost rate until its next base rate case in  
7       which Kentucky Power will then provide updated avoided capacity costs based on a proxy  
8       unit calculation.”<sup>2</sup> Accordingly, COGEN tariff capacity credits were calculated utilizing  
9       an avoided generation capacity cost using information presented in Kentucky Power’s 2022  
10      Integrated Resource Plan. The specific proxy unit that the Commission cited, a 480MW  
11      natural gas combustion turbine, was used in this calculation with dollars adjusted to 2025.  
12      The inputs and calculations are shown in Exhibit MMS-1.

**VI. REVENUE AND OPERATING EXPENSE ADJUSTMENTS**

13   **Q.   PLEASE IDENTIFY AND DISCUSS EACH OF THE REVENUE AND**  
14      **OPERATING EXPENSE ADJUSTMENTS THAT YOU ARE SPONSORING.**

15   A.   The details of the revenue and operating expense adjustments are set forth on various pages  
16      of Section V, Exhibit 2 to the application. Specifically, I am sponsoring the following  
17      adjustments:

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<sup>2</sup> Order at 72, *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, (Ky. P.S.C. Jan. 19, 2024).

<u>Adjustment</u>	<u>Exhibit Page No.</u>
Reset OSS Margin Baseline to Test Year	W1
Recognize Accrued Surcharge Revenue Differences	W2
Book to Bill	W3
Remove Federal Tax Cut Rider Revenues	W4
Annualize Base Rate Revenues	W5
Customer Annualization Adjustment	W14
Weather Normal Revenue Adjustment	W15
Adjust PJM LSE OATT Expense	W16

**Reset Off System Sales (OSS) Margins Baseline**  
**(Section V, Exhibit 2, W1)**

10 **Q. PLEASE EXPLAIN WHY THE COMPANY MUST RESET THE OSS MARGINS**  
11 **BASELINE.**

12 A. As discussed above, through the System Sales Clause, the Company shares with customers  
13 the difference between the embedded base rate credit for OSS margins and the actual OSS  
14 margins realized. The purpose of this adjustment is to reset the base rate credit for OSS  
15 margins included in the cost-of-service to the test year level of OSS margins. The test year  
16 amount of OSS margins is \$4,425,300.

17 **Q. HOW WAS THIS ADJUSTMENT CALCULATED?**

18 A. To adjust the base rate cost-of-service so that it only reflects the test year amount of OSS  
19 margins, two items must be accounted for: (1) System Sales Clause retail revenues and (2)  
20 the deferral related to the System Sales Clause. During the test year, the System Sales  
21 Clause collected \$2,278,308 from customers because actual OSS margins were less than

1 the amount included in base rates. This \$2.3 million credit to retail revenues was removed  
2 from the base rate cost-of-service as part of this adjustment. During the test year, an  
3 accounting deferral relating to the System Sales Clause was recorded on the Company's  
4 books in the amount of \$4,727,891. This amount was reversed as part of this adjustment to  
5 remove the test year deferral's effect on the base rate cost-of-service.

6 The net effect of these two items in Adjustment W1 is a \$2,449,583 increase to the  
7 base rate cost-of-service and resets the base rate OSS margin credit level to \$4,425,300.

**Surcharge Book to Bill Adjustment**  
**(Section V, Exhibit 2, W2)**

8 **Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR**  
9 **LEVEL OF SALES REVENUES.**

10 A. This adjustment accounts for the difference between the cost-of-service adjustments that  
11 remove various surcharges from the test year sales revenues and the billing analysis, which  
12 evaluates the expected revenues for the same surcharges. This adjustment reduces firm  
13 sales revenues by \$515,362.

**Book to Bill Adjustment**  
**(Section V, Exhibit 2, W3)**

14 **Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR**  
15 **LEVEL OF SALES REVENUES.**

16 A. This adjustment compares the test year billing analysis for firm sales revenue against the  
17 test year income statement (books) level of firm sales revenue and adjusts the  
18 cost-of-service to the level supported by the billing analysis. In the sequence of revenue  
19 adjustments related to billing units, the book to bill adjustment is computed first and utilizes

1 unadjusted test year billing units. This adjustment increases test year firm sales revenue by  
2 \$145,034.

**Remove Federal Tax Cut Rider Revenues**  
**(Section V, Exhibit 2, W4)**

3 **Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR**  
4 **LEVEL OF SALES REVENUES.**

5 A. Test year revenue credits resulting from the Tariff F.T.C. are included in firm sales and  
6 need to be removed in order to arrive at the correct level of adjusted base rate revenues  
7 which are the subject of this case. The removal of the test year F.T.C. rate credits increases  
8 firm sales revenue by \$2,712,449.

**Annualize Base Rate Revenues**  
**(Section V, Exhibit 2, W5)**

9 **Q. PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR**  
10 **LEVEL OF BASE RATE REVENUES.**

11 A. During the test year there were changes to base fuel rate as well as the implementation of  
12 updated rates across tariff classes arising from the Franklin Circuit Court's  
13 January 25, 2025 Order in Case No. 24-CI-00160, reversing the Commission's January 19,  
14 2024 Order in Case No. 2023-00159. This adjustment recognizes the differences between  
15 per books revenue and these changes during the test year and increases revenue by  
16 \$33,001,097.

**Year-End Number of Customers Annualization**  
**(Section V, Exhibit 2, W14)**

1    **Q.    PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO TEST YEAR FIRM**  
2       **SALES REVENUE.**

3    A.    The purpose of the year-end customer annualization adjustment is to restate test year  
4       revenues and expenses to reflect on an annual basis, changes in customers that occurred  
5       during the test year. For example, if the number of residential customers increased during  
6       the test year, per-books residential kWh sales would have to be increased to reflect the  
7       impact of annualizing load growth that occurred within the test year. In addition to the  
8       revenue adjustment, test year variable operating expenses would also have to be increased  
9       or decreased to reflect the incremental costs associated with annualizing test year load  
10      growth or decline.

11   **Q.    HOW IS THE YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT**  
12      **CALCULATED?**

13   A.    The year-end customer annualization adjustment begins with the number of customers in  
14       each tariff class at the end of the historic test year and adds or subtracts usage from the test  
15       year amounts by the average amount of usage per customer. These adjusted billing units  
16       then calculate the new adjusted firm sales revenues for the various tariffs.

17           In addition to the impact on firm sales revenue, the year-end customer annualization  
18       adjustment reflects a change in variable operating expense that would also change based  
19       on load growth or decline. The year-end customer annualization adjustment decreases firm  
20       sales revenues by \$3,776,112 and increases operation and maintenance expense by  
21       \$1,596,918.

**Adjust Firm Sales for Normal Weather**  
**(Section V, Exhibit 2, W15)**

1    **Q.    PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT.**

2    A.    The purpose of the weather normalization adjustment is to restate test year revenues and  
3           expenses to reflect average load for weather sensitive customers compared to the weather  
4           experienced during the test year. The Company bases its weather normalization on  
5           deviations from normal in both heating and cooling degree-days.

6           Using data provided by the Company's economic forecasting group, the adjustment  
7           was calculated to increase test year energy usage to the level of the average.<sup>3</sup> The result of  
8           this adjustment was to decrease total usage by approximately eight million kilowatt-hours  
9           and decrease revenues by \$1,012,932. The weather normalization adjustment also reflects  
10          the change in variable operating expense that the Company would experience based on this  
11          negative adjustment to test year load. Accordingly, this adjustment decreases operation and  
12          maintenance expense by \$428,369.

**Adjust Test Year PJM LSE OATT Expense to Going Level**  
**(Section V, Exhibit 2, W16)**

13   **Q.    PLEASE EXPLAIN THE ADJUSTMENT YOU MADE TO THE TEST YEAR**  
14   **LEVEL OF PJM LSE OATT EXPENSE.**

15   A.    The FERC-approved Open Access Transmission Tariff ("OATT") includes rates and  
16           billing units that are different in 2025 than they were in 2024, and as a result, the test year  
17           FERC-approved PJM LSE OATT expense must be revised to account for these differences.  
18           This adjustment increases the Kentucky retail jurisdiction base rate cost-of-service by  
19           \$9,981,873 for a total adjusted test year PJM LSE OATT expense level of \$152,262,631.

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<sup>3</sup> The 2024 period used a 30-year average load while the 2025 period used a 20-year average load.

**VII. ECONOMIC DEVELOPMENT RIDER PARTICIPATING CUSTOMER ANALYSIS  
AND SPECIAL CONTRACT DEVELOPMENT**

1    **Q.    HAVE YOU CONDUCTED A MARGINAL COST-OF-SERVICE ANALYSIS FOR**  
2           **THE COMPANY’S ECONOMIC DEVELOPMENT RIDER (“E.D.R.”)**  
3           **CUSTOMER AND WHAT ARE ITS RESULTS?**

4    A.    Yes. The marginal cost-of-service analysis shows that in total the Company’s E.D.R.  
5           customers are covering their variable cost-of-service and contributing to the Company’s  
6           fixed cost-of-service while taking service under the discounted E.D.R. rates. This analysis  
7           is attached to my Direct Testimony as Exhibit MMS-2. It was also filed with the  
8           Commission on March 30, 2025, in Case No. 2014-00336.

9    **Q.    HAVE YOU CONDUCTED A MARGINAL COST-OF-SERVICE ANALYSIS FOR**  
10          **THE COMPANY’S SPECIAL CONTRACT CUSTOMER?**

11   A.    Yes. I have calculated the marginal cost-of-service for the special contract customer for the  
12          periods of June 2023 through May 2025. The results are attached as Exhibit MMS-3.

**VIII. CONCLUSION**


13   **Q.    DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

14   A.    Yes, it does.



## 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.

  
\_\_\_\_\_  
Michael M. Spaeth

State of Ohio  
\_\_\_\_\_  
\_\_\_\_\_

} Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County  
and State, by Michael M. Spaeth, on 8-27-25

  
\_\_\_\_\_  
Notary Public



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 No ID

Kentucky Power Company  
Base Rate Revenue Target Summary  
Twelve Months Ended May 31, 2025

KPCo Kentucky Retail Jurisdiction  
Base Rate Revenue Target Summary

	Total Retail	From CCOS	RS	GS-SEC	3	GS-SEC	6	LGS-SEC	7	LGS-SEC	8	LGS-TRA	Total LGS	LGS-SEC	10	LGS-SEC	11	LGS-SUB	13	LGS-TRA	Total LGS	PS-SEC	14	PS-PHI	Total PS	MW	OL	NJ	18						
\$	262,759,815		\$	106,763,036	\$	38,833,621	\$	20,637,741	\$	433,555	\$	64,636	\$	26,803,488	\$	855,673	\$	9,138,351	\$	9,802,216	\$	82,852,069	\$	150,662	\$	6,340,244	\$	107,560	\$	495,648	\$	140,285			
Demand	\$	222,654,711		\$	79,246,649	\$	26,495,761	\$	13,283,921	\$	288,805	\$	15,372	\$	3,674,750	\$	853,678	\$	10,043,038	\$	11,481,880	\$	93,612,783	\$	86,506	\$	3,750,789	\$	84,448	\$	1,418,495	\$	362,577		
Energy	\$	59,244,610		\$	32,148,700	\$	12,449,667	\$	7,005,424	\$	1,911,738	\$	-	\$	8,917,062	\$	263,001	\$	2,977,396	\$	-	\$	3,340,397	\$	51,282	\$	2,171,755	\$	36,503	\$	114,548	\$	33,272		
Dist Primary	\$	20,322,587		\$	12,933,752	\$	4,418,800	\$	2,023,413	\$	-	\$	-	\$	2,023,413	\$	59,427	\$	-	\$	-	\$	59,427	\$	-	\$	627,233	\$	10,234	\$	193,880	\$	55,448		
Dist Secondary	\$	107,057,068		\$	72,250,856	\$	24,465,859	\$	4,783,886	\$	1,665,603	\$	71,313	\$	73,681	\$	4,843	\$	75,371	\$	96,366	\$	262,430	\$	2,484	\$	181,468	\$	10,743	\$	7,576,741	\$	1,407,414		
Customer	\$	672,038,790		\$	303,342,973	\$	106,661,709	\$	43,428,885	\$	11,420,607	\$	793,673	\$	220,588	\$	55,863,752	\$	222,341,56	\$	21,520,462	\$	180,027,107	\$	290,934	\$	13,071,489	\$	249,488	\$	9,799,312	\$	1,999,335		
Adjustments																																			
Unbilled	\$	(10,360,547)		\$	(4,768,043)	\$	(2,166,149)	\$	(982,146)	\$	(261,214)	\$	(19,075)	\$	(60,643)	\$	(481,980)	\$	(425,834)	\$	(648,522)	\$	(277,725)	\$	(5,411)	\$	(9,244)	\$	(229,730)	\$	231	\$	64,40		
D	\$	(5,808,246)		\$	(2,736,689,20)	\$	(1,287,619,62)	\$	(597,531,65)	\$	(158,466,84)	\$	(11,448,69)	\$	(30,536,74)	\$	(229,623,53)	\$	(199,950,17)	\$	(298,671,46)	\$	(103,275,34)	\$	(1,973,74)	\$	(5,178,47)	\$	(59,486,13)	\$	(4,065,75)	\$	(170,243,51)	\$	166,45
E	\$	(4,552,301)		\$	(2,031,353,32)	\$	(878,528,99)	\$	(384,613,96)	\$	(102,747,30)	\$	(7,626,35)	\$	(30,285,98)	\$	(252,356,04)	\$	(225,883,76)	\$	(349,850,44)	\$		\$		\$		\$		\$		\$			
Base Rate Revenue Targets																																			
Demand	\$	268,568,062		\$	109,499,726	\$	40,121,241	\$	21,255,273	\$	5,826,022	\$	63,739	\$	27,570,038	\$	886,029	\$	9,367,974	\$	10,000,888	\$	83,610,671	\$	154,100	\$	6,518,131	\$	112,738	\$	555,134	\$	140,221		
Energy	\$	227,207,011		\$	81,278,002	\$	27,374,290	\$	13,688,535	\$	3,777,497	\$	296,431	\$	17,875,956	\$	883,684	\$	10,295,394	\$	11,831,730	\$	94,471,159	\$	88,480	\$	3,856,038	\$	88,514	\$	1,588,739	\$	362,410		
Dist Primary	\$	59,244,610		\$	32,148,700	\$	12,449,667	\$	7,005,424	\$	1,911,738	\$	-	\$	8,917,062	\$	263,001	\$	2,977,396	\$	-	\$	3,340,397	\$	51,282	\$	2,171,755	\$	36,503	\$	114,548	\$	33,272		
Dist Secondary	\$	20,322,587		\$	12,933,752	\$	4,418,800	\$	2,023,413	\$	-	\$	-	\$	2,023,413	\$	59,427	\$	-	\$	-	\$	59,427	\$	-	\$	627,233	\$	10,234	\$	193,880	\$	55,448		
Customer	\$	107,057,068		\$	72,250,856	\$	24,465,859	\$	4,783,886	\$	1,665,603	\$	71,313	\$	73,681	\$	4,843	\$	75,371	\$	96,366	\$	262,430	\$	2,484	\$	181,468	\$	10,743	\$	7,576,741	\$	1,407,414		
TOTAL	\$	682,399,337		\$	308,111,016	\$	108,827,857	\$	44,411,030	\$	11,681,821	\$	812,748	\$	217,811	\$	57,123,410	\$	22,716,136	\$	21,598,584	\$	181,644,083	\$	296,346	\$	13,354,625	\$	238,732	\$	10,029,042	\$	1,999,164		

Kentucky Power Company  
RES Rate Design  
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**I. Proposed Revenue**

	Billed & Accrued Revenue	Fuel Revenue	Base Revenue	
Total RS Revenue Requirement				
Demand	154,582,178	\$0	\$154,582,178	
Energy	81,278,002	0	\$81,278,002	
Customer	72,250,836	0	\$72,250,836	
Total	\$308,111,016	\$0	\$308,111,016	\$4,768,043 Unbilled

**II. Customer Charge**

<u>kWh Threshold</u>		kWh	% of Cust	Number of Customers	Customer Charge Rate	Customer Charge Revenue	Manual Rate Input
2000 Tier 1		0 - 2000	84.04%	1,314,461	\$ 26.00	\$ 34,175,986	\$ 26.00
0 Tier 2		2000+	15.96%	249,681	\$ 40.00	\$ 9,987,240	
Percentage of Full Cost Customer Charge		61%				\$ 44,041,544	
Calculated Std Customer Charge	\$	28.16				Full Cost Customer Charge	\$ 46.19
Customer Charge Rounding Adjustment						\$ (121,682)	
Tier 1 Proposed Customer Charge					=	\$26.00 /mo.	
Proposed Customer Charge Revenue			1,316,321	x	\$26.00	=	\$34,224,346

**III. Off-Peak Energy Charge**

Energy Revenue Requirement	\$81,278,002			
Total Energy (kWh)	1,889,849,938			
Total Secondary Energy Charge	\$0.04301 /kWh			
Fixed Cost Adder	\$0.05016 /kWh			
Proposed Off-Peak Energy Charge	\$0.09317 /kWh			
Off-Peak % Usage	56.32%			
Off-Peak kWh Energy	1,064,388,417			
Off-Peak Revenue	1,064,388,417	x	\$0.09317	= \$99,169,069

**IV. On-Peak Energy Charge**

Total RS Base Revenue	\$308,111,016
Less: Customer Revenue	44,163,226
Less: Off-Peak Energy Revenue	99,169,069
On-Peak Revenue	\$164,778,721
Total RS Energy	1,889,849,938
Less: Off-Peak kWh Energy	1,064,388,417
On-Peak kWh Energy	825,461,521
Proposed On-Peak Energy Charge	\$0.19962 /kWh

**V. Revenue Verification**

	Units	Rate	Revenue	Difference
On-Peak	825,461,521 kWh	\$0.19962 /kWh	\$164,778,629	
Off-Peak	1,064,388,417 kWh	\$0.09317 /kWh	99,169,069	
Customer	1,316,321 Bills	\$26.00 /Mo.	34,224,346	
Total	1,889,849,938 kWh		\$298,172,044	(9,938,972)

**VI. Time-of-Day Customer Charges**

Current TOD Charge	\$23.00		
Proposed Standard Charge	\$26.00	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	14.61%	14.61%	15 Year Annual Investment CC
Over 12 Months	12	12	
Differential	\$3.15	\$4.47	
Proposed RS-TOD/RS-LM-TOD/ RS TOD 2	\$29.00	\$4.45	

Kentucky Power Company  
RES Rate Design  
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Separate Meter Customer Charge: Current \$3.75  
Use: \$4.45

**VII. RS-TOD / RS-LM-TOD Proposed Revenue**

	Units	Rate	Revenue
On-Peak	1,187,315 kWh	\$0.19962 /kWh	\$237,012
Off-Peak	1,809,447 kWh	\$0.09317 /kWh	168,586
Customer - Std TOD	1,764 Bills	\$29.00 /Mo.	51,156
Customer - Sep Meter	96 Bills	\$4.45 /Mo.	427
Total	2,996,762 kWh		\$457,181

**VIII. Customer Revenue**

Customer Charge Revenue 1,564,142 Bills x \$26.00 /mo. = \$40,667,692

**IX. Standard Energy Rates**

Storage Water Heating Revenue 473,546 kWh x \$0.09317 /kWh (Off-Pk) = \$44,120

Adjusted Base Revenue 308,111,016  
Less RS-TOD/RS-LM-TOD Revenue 457,181  
Less: Customer Revenue 40,667,692  
Less: Storage Water Htg Revenue 44,120

kWh Blocking	kWh Blocks	% of Cust	Kwh	Energy Rate	Energy Revenue	Manual Rate Input
600 Block 1	0 - 600	43.13%	813,786,921	0.15750	128,171,440 \$	0.157500
0 Block 2	601 +	56.87%	1,073,066,255	0.12606	135,319,596 \$	-
0 Block 3	0	0%	-	0.00000	0 \$	-
Standard			1,886,853,176	0.13965	263,491,036	

Energy Charge Revenue - All Blocks \$266,942,023  
All kWh 1,886,379,630

Standard Energy Rate - All kWh \$0.14151 /kWh

**X. RS Revenue Verification**

	Units	Rate	Revenue
Block 1 kWh	813,786,921 kWh	\$0.15750 /kWh	\$128,171,440
Block 2 kWh	1,073,066,255 kWh	\$0.12606 /kWh	\$135,275,600
Block 3 kWh	0 kWh	\$0.00000 /kWh	\$0
Storage Water Heating	473,546 kWh	\$0.09317 /kWh	44,120
Tier 1 Customer	1,314,461 Bills	\$26.00 /mo.	34,175,986
Tier 2 Customer	249,681 Bills	\$40.00 /mo.	9,987,240
Total	1,887,326,722 kWh		
		Proof	\$307,654,386
		Standard Target	\$307,653,835
		Difference	\$551

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XIV. Residential Summary

Schedule	Bills	kWh	Revenue	Difference
RS	1,314,461	1,887,326,722	\$307,654,386	
RS-TOD / RS LMTOD	1,860	2,996,762	457,181	
Total Billed	1,316,321	1,890,323,484	\$308,111,567	\$551

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**Optional Residential Demand Rate**

Revenue Targets	
Distribution Primary	\$ 32,148,700
Distribution Secondary	\$ 12,933,752
Prod and Trans Demand	\$ 109,499,726
Energy	\$ 81,278,002
Customer	\$ 72,250,836
Total	\$ 308,111,016

RS-D Billing Units	
On Peak kWh	286,203,040
Off Peak Energy	1,603,646,898
Total kWh	1,889,849,938
Total On-Peak Billing Demand	10,371,705
Total Bills	1,316,321

RS-D Rates	
On Peak Energy Charge	<b>0.14464</b> \$/kWh
Off Peak Energy Charge	<b>0.09317</b> \$/kWh
On-Peak Demand Charge	<b>8.01</b> \$/kW
Customer Charge	<b>26.00</b> \$/customer/month

Revenue Verification	Units	Rates	Revenue
On Peak Energy Charge	286,203,040	0.14464	\$ 41,396,408
Off Peak Energy Charge	1,603,646,898	0.09317	\$ 149,411,782
On-Peak Demand Charge per kW	10,371,705	8.01	\$ 83,077,357
Customer Charge	1,316,321	26.00	\$ 34,224,346
Block 1 of STD RES			\$ 308,109,892
			\$ (1,124)

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RES Rate Design  
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RS TOD2

I. Proposed Revenue

	<u>Total</u> (1)	<u>Production</u> (2)	<u>All Other</u> (3) = (1) - (2)
Demand	154,582,178	\$106,763,036	\$47,819,141
Energy	81,278,002	\$0	\$81,278,002
Customer	72,250,836	\$0	\$72,250,836
Total	\$308,111,016	\$106,763,036	\$201,347,980

III. Basic Energy Charge Rate Design

All Other Revenue	\$201,347,980
Less: Customer Charge Revenue - STD	\$40,667,692
Customer Charge Revenue - TOD	\$51,583
Basic Energy Revenue	\$160,628,705
Total kWh	1,889,849,938
Basic Energy Charge Rate	\$0.084995

IV. Variable Energy Charge Rate Design

	<u>Market Generation (Excluding Losses)</u>				<u>Variable Energy</u> <u>Charge</u> (6) = (4) / (5)
	<u>Energy</u> (1)	<u>Capacity</u> (2)	<u>Total</u> (3) = (1) + (2)	<u>Production Charge</u> (4) on (3)	<u>kWh</u> (5)
Summer	7,115,586	7,704,537	14,820,123	\$15,150,733	124,158,891
Winter	15,956,189	7,458,534	23,414,723	\$23,937,063	255,160,209
Other	60,154,451	6,044,021	66,198,472	\$67,675,240	1,510,530,839
	83,226,226	21,207,092	104,433,318	\$106,763,036	1,889,849,938
			Percentage:	102.23%	

V. Energy Base Rate Total

	<u>Basic Energy</u> <u>Charge</u> (1)	<u>Variable Energy</u> <u>Charge</u> (2)	<u>Subtotal</u> (3) = (1) + (2)	<u>Fuel Adjustment</u> (4)	<u>Base Rate</u> (5) = (3) - (4)
Summer	\$0.084995	\$0.122027	\$0.207022	\$0.0000000	\$0.20702
Winter	\$0.084995	\$0.093812	\$0.178807	\$0.0000000	\$0.17881
Other	\$0.084995	\$0.044802	\$0.129797	\$0.0000000	\$0.12980

VI. Revenue Verification

	<u>Units</u> (1)	<u>Rate</u> (2)	<u>Revenue</u> (3) = (1) x (2)		
Customer Charge - STD	1,564,142 Bills	\$26.00	\$40,667,692		
Customer Charge - TOD	1,764 Bills	\$29.00	\$51,156		
Customer Charge - TOD - Sep Meter	96 Bills	\$4.45	\$427		
Summer	124,158,891 kWh	\$0.20702	\$25,703,374		
Winter	255,160,209 kWh	\$0.17881	\$45,625,197		
Other	1,510,530,839 kWh	\$0.12980	\$196,066,903		
Fuel	1,889,849,938 kWh	\$0.0000000	\$0		
			\$308,114,749	\$308,111,016	\$3,733

Kentucky Power Company  
GS Rate Design  
Twelve Months Ended May 31, 2025

General Service (GS)

I. Proposed Revenue

	<u>Secondary</u>	<u>Primary</u>	<u>Subtran</u>	<u>Trans</u>	<u>Total</u>
<u>Proposed Base Revenue</u>					
Demand	\$56,989,708	\$566,067	\$6,702		
Energy	\$27,374,290	\$305,135	\$6,767		
Customer	\$24,463,859	\$153,053	\$13,681		
	<u>\$108,827,857</u>	<u>\$1,024,256</u>	<u>\$27,150</u>		<u>\$109,879,263</u>
Fuel Revenue	\$0	\$0	\$0		
Total Base Revenue	<u>\$108,827,857</u>	<u>\$1,024,256</u>	<u>\$27,150</u>		<u>\$109,879,263</u>

Secondary Tariff Provisions Base Rev

Less SGS TOD	\$1,315,682
Less MGS TOD	\$1,114,602
Less GS LMTOD	\$250,711
Less Rec Lighting	<u>\$240,390</u>
	<u>\$2,921,385</u>

Standard GS Base Revenue Targets

	<u>Secondary</u>	<u>Primary</u>	<u>Subtran</u>
Demand	\$55,459,870	\$566,067	\$6,702
Energy	\$26,639,452	\$305,135	\$6,767
Customer	<u>\$23,807,149</u>	<u>\$153,053</u>	<u>\$13,681</u>
	<u>\$105,906,472</u>	<u>\$1,024,256</u>	<u>\$27,150</u>

II. Billing Determinant Summary

	\$52,756		
Standard Service Charge	349,392	840	36
Non-Metered Service Charge	10,908		
First 4450 kWh	352,087,318	2,345,002	101,116
Over 4450 kWh	<u>239,355,098</u>	<u>4,958,313</u>	<u>86,827</u>
Total kWh	<u>591,442,417</u>	<u>7,303,315</u>	<u>187,943</u>
Billing Demand Greater Than 10 kW	1,139,318	19,827	71

III. GS LMTOD

	<u>Revenue</u>	<u>Units</u>	<u>Rates</u>
On Peak	\$145,482	633,825	0.22953
Off Peak	\$82,165	865,532	0.09493
Customer	<u>\$23,064</u>	<u>744</u>	<u>31.00</u>
\$	<u>250,711</u>		

IV. Recreational Lighting

	<u>Units</u>	<u>Rates</u>	<u>Revenue</u>
Service Charge	1,068	\$ 31.00	\$ 33,108
Energy Charge	1,299,575	\$0.15950 *	<u>\$ 207,282</u>
			<u>\$ 240,390</u>

\* Limited after Revenue Verification

V. Service Charge Revenue

	<u>Customer Revenue</u>	<u>Bills</u>	<u>Full Cost Rate</u>	<u>Current Rate</u>	<u>Proposed Rate</u>
Secondary	\$23,807,149	349,392	\$ 68.14	\$ 28.00	\$ 31.00
Primary	\$153,053	840	\$ 182.21	\$ 120.00	\$ 140.00
Subtransmission	\$13,681	36	\$ 380.03	\$ 460.00	\$ 460.00

Proposed Customer Revenue

	<u>Proposed Rate</u>	<u>Bills</u>	<u>Revenue</u>
Secondary	\$ 31.00	349,392	\$ 10,831,152
Primary	\$ 140.00	840	\$ 117,600
Subtransmission	\$ 460.00	36	\$ 16,560
Non-Metered	\$ 17.00	10,908	<u>\$ 185,436</u>
			<u>\$ 11,150,748</u>

VI. Proposed Energy Charges and Revenue

Proposed Energy Charges

	<u>Units</u>	<u>Proposed Charges</u>	<u>Proposed Energy Revenue</u>	<u>current</u>	<u>class avg inc</u>
<u>Secondary</u>					
First 4450 kWh	352,087,318	0.14562	\$ 51,270,955	0.13060	11.5% GS Class Incr
Over 4450 kWh	239,355,098	0.11853	\$ 28,370,760	0.11581	2.35% Toggle
<u>Primary</u>					
First 4450 kWh	2,345,002	0.12887	\$ 302,200	0.11558	
Over 4450 kWh	4,958,313	0.10543	\$ 522,755	0.10301	
<u>Subtransmission</u>					
First 4450 kWh	101,116	0.11742	\$ 11,873	0.10531	
Over 4450 kWh	86,827	0.09618	<u>\$ 8,351</u>	<u>0.09397</u>	
Total Energy Revenue			\$ 80,486,894		



Kentucky Power Company  
GS Rate Design  
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VII. Proposed Demand Charges and Revenue

Total Base Revenue	\$109,879,263
less Secondary Tariff Provisions (TODs)	\$2,921,385
less Service Charge Revenue	\$11,150,748
less Energy Charge Revenue	\$80,486,894
less Equipment Credit Revenue	<u>-\$17,739</u>
Proposed Demand Revenue	\$15,337,975
Loss Adjusted Billing Demand	1,158,562
Residual Demand Charge	13.24

	Billing Demand	Loss Factor	Loss Adjusted Demand
Secondary	1,139,318	1.000	1,139,318
Primary	19,827	0.967	19,176
Subtransmission	71	0.954	68
Total	<u>1,159,215</u>		<u>1,158,562</u>

	Billing Demand	45% of Equipment Credit	Revenue
Secondary	1,139,318	\$ -	\$ -
Primary	19,827	\$ (0.88)	\$ (17,487)
Subtransmission	71	\$ (3.55)	\$ (252)
Total	<u>1,159,215</u>		<u>\$ (17,739)</u>

	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Demand Rate Mitigation	Proposed Rate	Proposed Revenue	Current Rates	% increase
Secondary	13.24	1.000	13.24	\$ -		13.24	\$ 15,084,566	\$ 8.36	58%
Primary	13.24	0.967	12.81	\$ (0.88)	\$ (0.07)	11.85	\$ 235,019	\$ 7.56	57%
Subtransmission	13.24	0.954	12.63	\$ (3.55)		9.07	\$ 644	\$ 5.84	55%
Transmission	13.24	0.940	12.45	\$ (3.55)		8.90			
							<u>\$ 15,320,230</u>		

VIII. Revenue Verification

	Units	Rates	Revenue	Target	Difference
<u>Secondary</u>					
First 4450 kWh	352,087,318	0.14562	\$ 51,270,955		
Over 4450 kWh	239,355,098	0.11853	\$ 28,370,760		
Billing Demand	1,139,318	\$ 13.24	\$ 15,084,566		
Customer - Standard	349,392	\$ 31.00	\$ 10,831,152		
Customer - Non-Metered	10,908	\$ 17.00	\$ 185,436		
<u>Primary</u>				\$ 105,742,869	
First 4450 kWh	2,345,002	0.12887	\$ 302,200		
Over 4450 kWh	4,958,313	0.10543	\$ 522,755		
Billing Demand	19,827	\$ 11.85	\$ 235,019		
Customer	840	\$ 140.00	\$ 117,600		
<u>Subtransmission</u>				\$ 1,177,575	
First 4450 kWh	101,116	0.11742	\$ 11,873		
Over 4450 kWh	86,827	0.09618	\$ 8,351		
Billing Demand	71	\$ 9.07	\$ 644		
Customer	36	\$ 460.00	\$ 16,560		
			\$ 106,957,872	\$ 106,957,878	\$ (5)

Kentucky Power Company  
GS AF NM Rate Design  
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GS Secondary for TOD/LMTOD/AF Cales

I. <u>Proposed Revenue</u>	Billed & Accrued Revenue	Fuel Revenue	Billed & Accrued Revenue Excld Fuel	Base Revenue
Demand	\$56,989,708	\$0	\$56,989,708	\$56,989,708
Energy	27,374,290	0	\$27,374,290	27,374,290
Customer	24,463,859	0	\$24,463,859	24,463,859
Total	\$108,827,857	\$0	\$108,827,857	\$108,827,857

II. Non-Metered Customer Charge

Meter Plant (370)	\$6,611,381	CCOSS GS SEC 370	Customer Base Revenue	\$24,463,859
Net Plant/Gross Plant Percentage	56.35%	Sec Net EPIS/EI	Less: Meter Plant Revenue	498,630
Depreciated Meter Plant	3,725,311		Meter Sec O&M Expense (586 & 597)	338,542
Return on Rate Base - Class Proposed	10.00%		Meter Sec Reading Expense (902)	98,090
Income	372,531		Adj. Customer Revenue	23,528,597
GRCF	1,338,493		/ Bills	376,296
Meter Plant Revenue	498,630		Calculated Non-Metered Customer Charge	62.53
			Current	\$15.00
			Use:	\$17.00

III. Standard Customer Charge

Customer Revenue	\$24,463,859					Overall % increase
Less: Non-Metered Customer Rev.	185,436					11.50%
Residual Customer Revenue	\$24,278,423	/	358,776	Bills	=	\$67.67 /mo.
				Current	=	\$28.00 /mo.
				Use:		\$31.00 /mo.

GS Sec			349,392			
SGS TOD			5,868			
GS AF			1,068			
MGS TOD			1,704			
GS LMTOD			744			
Standard	\$31.00	x	358,776	Bills	=	\$11,122,056
GS Non-Metered	\$17.00	x	10,908	Bills	=	\$185,436

IV. Energy Charges

Revenue Requirement	\$108,827,857				
Less: Standard Customer Revenue	11,122,056				
Less: Non-Metered Customer Revenue	185,436				
Energy Rate Target	\$97,520,365				
GS Sec Standard Energy	591,442,417				
SGS TOD	7,320,966				
GS AF	1,299,575		8,519,716		
MGS TOD	7,251,724		1,798,726		
GS LMTOD	1,499,357		1,415,369		
GS NM	2,616,378				
Total GS Sec Energy	611,430,417				
Recreational Lighting (AF) Energy Rate	\$97,520,365	/	611,430,417	=	\$0.15950

V. Revenue Verification

	Units	Rate	Revenue	Difference
Energy	611,430,417 kWh	\$0.15950 /kWh	\$97,523,152	
Standard Customer	358,776 Bills	\$31.00 /mo	11,122,056	
Non-Metered Customer	10,908 Bills	\$17.00 /mo	185,436	
Total Base Revenue			\$108,830,644	\$2,787

Kentucky Power Company  
GS AF NM Rate Design  
Twelve Months Ended May 31, 2025

VI. Off-Peak Energy Charge

Energy Revenue Requirement	\$27,374,290 / 611,430,417 kwh	\$0.04477
Fixed Cost Adder		0.05016
Calculated Off-Peak Energy Charge		\$0.09493
Use		\$0.09493
Off-Peak % Usage		52.03%
Off-Peak kWh		318,146,135
Off-Peak Revenue		\$30,201,613

VII. On-Peak Energy Charge

Total GS Sec Base Revenue	\$108,827,857
Less: Standard Customer Revenue	11,122,056
Non-Metered Customer Revenue	185,436
Time-of-Day Off-Peak Revenue	30,201,613
On-Peak Revenue	\$67,318,752
On-Peak kWh Energy	293,284,282
Proposed On-Peak Energy Charge	\$0.22953 /kWh

VIII. Secondary Revenue Verification

	<u>Units</u>	<u>Rate</u>	<u>Revenue</u>	<u>Difference</u>
On-Peak	293,284,282 kWh	\$0.22953	\$67,317,541	
Off-Peak	318,146,135 kWh	\$0.09493	30,201,613	
Standard Customer	358,776 Bills	\$31.00	11,122,056	
Non-Metered Customer	10,908 Bills	\$17.00	185,436	
Total Base Revenue			\$108,826,646	(\$1,211)

IX. Revenue From Existing TOD Customers

	<u>Units</u>	<u>Rate</u>	<u>Proposed Revenue</u>	<u>Current Rates</u>
GS-LM TOD				
On-Peak Energy	633,825	\$0.22953	145,482	0.19211
Off-Peak Energy	865,532	\$0.09493	82,165	0.09269
Customer	744	\$31.00	23,064	28
Total			\$250,711	
MGS TOD				
On-Peak Energy	2,773,932	\$0.22953	636,701	0.19211
Off-Peak Energy	4,477,792	\$0.09493	425,077	0.09269
Customer	1,704	\$31.00	52,824	28
Total			\$1,114,602	

Kentucky Power Company  
SGS TOD Rate Design  
Twelve Months Ended May 31, 2025

I. Proposed Revenue

	<u>Total</u> (1)	<u>Production</u> (2)	<u>All Other</u> (3) = (1) - (2)
Demand	\$56,989,708	\$40,121,241	\$16,868,467
Energy	\$27,374,290	\$0	\$27,374,290
Customer	\$24,463,859	\$0	\$24,463,859
Total	<u>\$108,827,857</u>	<u>\$40,121,241</u>	<u>\$68,706,616</u>

II. Incremental Meter Charge Rate Design

<u>Annual</u> <u>Incremental</u> <u>Meter Charge</u>	<u>Months</u>	<u>Carrying Charge</u>	<u>Incremental</u> <u>Customer Charge</u>	<u>Plus Standard</u>	<u>Proposed</u> <u>Customer Charge</u>
\$0.00	/ 12	x 11.42%	= \$0.00	+ \$31.00	= \$31.00

III. Basic Energy Charge Rate Design

All Other Revenue	\$68,706,616
Less: Customer Charge Revenue - STD	\$11,122,056
Customer Charge Revenue - LM-TOD	\$23,064
Customer Charge Revenue - NM	\$185,436
Customer Charge Revenue - TOD	<u>\$181,908</u>
Basic Energy Charge	<u>\$57,194,152</u>
Total kWh	620,250,740
Basic Energy Charge Rate	\$0.092211

IV. Variable Energy Charge Rate Design

	<u>Market Generation (Excl. Losses)</u>					<u>Variable Energy</u> <u>Charge</u>
	<u>RT LMP</u> (1)	<u>Capacity</u> (2)	<u>Total</u> (3) = (1) + (2)	<u>Production Charge</u> (4) on (3)	<u>kWh</u> (5)	(6) = (4) / (5)
Summer	2,633,991	3,314,479	5,948,470	\$6,813,441	48,586,994	\$0.140232
Winter	4,208,194	3,915,419	8,123,612	\$9,304,872	69,824,136	\$0.133262
Other	<u>18,382,387</u>	<u>2,573,353</u>	<u>20,955,740</u>	<u>\$24,002,928</u>	<u>501,839,610</u>	<u>\$0.047830</u>
	25,224,571	9,803,251	35,027,822	\$40,121,241	620,250,740	
			Percentage:	114.54%		

V. Energy Base Rate Total

	<u>Basic Energy</u> <u>Charge</u> (1)	<u>Variable Energy</u> <u>Charge</u> (2)	<u>Subtotal</u> (3) = (1) + (2)	<u>Fuel Adjustment</u> (4)	<u>Base Rate</u> (5) = (3) - (4)
Summer	\$0.092211	\$0.140232	\$0.232443	\$0.0000000	\$0.23244
Winter	\$0.092211	\$0.133262	\$0.225473	\$0.0000000	\$0.22547
Other	\$0.092211	\$0.047830	\$0.140041	\$0.0000000	\$0.14004

Kentucky Power Company  
SGS TOD Rate Design  
Twelve Months Ended May 31, 2025

VI. Revenue Verification

	<u>Units</u> (1)	<u>Rate</u> (2)	<u>Billing</u> (3) = (1) x (2)		
Customer Charge - STD	358,776 Bills	\$31.00	\$11,122,056		
Customer Charge - LM-TOD	744 Bills	\$31.00	\$23,064		
Customer Charge - NM	10,908 Bills	\$17.00	\$185,436		
Customer Charge - TOD	5,868 Bills	\$31.00	\$181,908		
Summer	48,586,994 kWh	\$0.23244	\$11,293,561		
Winter	69,824,136 kWh	\$0.22547	\$15,743,248		
Other	501,839,610 kWh	\$0.14004	\$70,277,619		
Fuel	620,250,740 kWh	\$0.0000000	\$0		
			<u>\$108,826,892</u>	\$108,827,857	(\$965)

VII. Revenue From Existing SGS-TOD Customers

	<u>Units</u>	<u>Rate</u>	<u>Billing</u>	Current
SGS-TOD				
Summer	490,454	\$0.23244	\$114,001	0.20185
Winter	740,116	\$0.22547	\$166,874	0.14461
Other	6,090,395	\$0.14004	\$852,899	0.13034
Customer	5,868	\$31.00	<u>\$181,908</u>	
Total			\$1,315,682	

Kentucky Power Company  
LGS Rate Design  
Twelve Months Ended May 31, 2025

I. Proposed Revenue		Billed and Accrued Revenue	Fuel Revenue	Base Revenue
Secondary	<b>Includes Schools</b>			
Demand		\$39,375,847	\$0	\$39,375,847
Energy		17,436,093	0	17,436,093
Customer		657,370	0	657,370
Total		\$57,469,310	\$0	\$57,469,310
Secondary LM-TOD & TOD		\$1,181,880	\$0	\$1,181,880
Secondary Excl. LM-TOD				
Demand		\$38,566,065	\$0	\$38,566,065
Energy		17,077,513	0	17,077,513
Customer		643,851	0	643,851
Total		\$56,287,429	\$0	\$56,287,429
Primary	<b>Includes Schools</b>			
Demand		\$7,943,142	\$0	\$7,943,142
Energy		3,865,978	0	3,865,978
Customer		169,047	0	169,047
Total		\$11,978,167	\$0	\$11,978,167
Subtransmission				
Demand		\$445,004	\$0	\$445,004
Energy		296,431	0	296,431
Customer		71,313	0	71,313
Total		\$812,748	\$0	\$812,748
Transmission				
Demand		\$63,739	\$0	\$63,739
Energy		133,492	0	133,492
Customer		20,580	0	20,580
Total		\$217,811	\$0	\$217,811
Total LGS Excl LMTOD				
Demand		\$47,017,950	\$0	\$47,017,950
Energy		21,373,414	0	21,373,414
Customer		904,791	0	904,791
Total		\$69,296,155	\$0	\$69,296,155

II. Billing Determinant Summary		<u>Secondary</u>	<u>Primary</u>	<u>Subtransmission</u>	<u>Transmission</u>
<u>Total LGS with Schools</u>					
Billing Demand		1,117,380	288,303	16,692	5,360
Billing Reactive		49,523	53,997	3,249	0
Billing kWh		368,420,987	84,822,808	6,934,309	1,436,000
Bills		5,772	708	84	24
<u>Schools</u>		<u>Secondary</u>	<u>Primary</u>		
Billing Demand		304,121	6,727		
Billing Reactive		6,510	102		
Billing kWh		79,850,554	1,968,499		
Bills		1,524	12		
<u>Standard LGS</u>		<u>Secondary</u>	<u>Primary</u>	<u>Subtransmission</u>	<u>Transmission</u>
Billing Demand		813,259	281,576	16,692	5,360
Billing Reactive		43,013	53,895	3,249	0
Billing kWh		288,570,433	82,854,309	6,934,309	1,436,000
Bills		4,248	696	84	24
avg kWh		63,829	119,806	82,551	59,833
avg kW		194	407	199	223

Kentucky Power Company  
LGS Rate Design  
Twelve Months Ended May 31, 2025

III. Proposed Customer Charges & Revenue

Proposed Customer Charge	Customer Revenue	Bills	Full Cost Rate	Proposed Rate	Overall % increase	Current Rate
Secondary	\$643,851	5,772	\$111.55	\$111.00	13.90%	97
Primary	169,047	708	\$238.77	\$166.00	13.90%	145
Subtransmission	71,313	84	\$848.96	\$849.00	13.90%	750
Transmission	20,580	24	\$857.50	\$849.00	13.90%	750
Total	\$904,791	6,588				
Proposed Customer Revenue	Proposed Rate	Bills	Customer Revenue			
Secondary	\$111.00	5,772	\$640,692			
Primary	\$166.00	708	117,528			
Subtransmission	\$849.00	84	71,316			
Transmission	\$849.00	24	20,376			
Total		6,588	\$849,912			

IV. Proposed Excess KVA Charges & Revenue

Proposed KVA Revenue	Proposed/Current Rate	Excess KVA	Revenue
Secondary	\$3.46	49,523	\$171,349
Primary	\$3.46	53,997	186,830
Subtransmission	\$3.46	3,249	11,240
Transmission	\$3.46	0	0
Total		106,769	\$369,419

V. Proposed Demand Charge and Revenue

Calculation of Loss Adj Demand	Maximum Demand	Loss Factor	Loss Adj Demand
Secondary	1,117,380	1.000	1,117,380
Primary	288,303	0.967	278,845
Subtransmission	16,692	0.954	15,917
Transmission	5,360	0.940	5,039
Demand	1,427,736		1,417,181

% of Demand EQ Credit

Equipment Credit Revenue	Maximum Demand	Equipment Credit	Credit Revenue
Secondary	1,117,380	0.00	\$0
Primary	288,303	(1.96)	(\$565,075)
Subtransmission	16,692	(7.89)	(\$131,700)
Transmission	5,360	(7.89)	(\$42,294)
Loss Adjusted Demand	1,427,736		(\$739,069)

Total Required Demand Revenue	\$46,648,531
Less: Equipment Credit Revenue	(739,069)

Demand Revenue	\$47,387,600
Loss Adjusted Maximum Demand	1,417,181

Full Cost Demand Charge	\$33.44
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Mitigated % of Demand in Demand Rate	\$13.38
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40% % Demand

Demand Charges	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Demand Rate	Current Demand Rate	Class Increase
							13.90%
Secondary	\$13.38	1.000	\$13.38	0.000	13.38	\$ 13.84	\$ 15.76
Primary	\$13.38	0.967	\$12.94	-1.960	10.98	\$ 12.23	\$ 13.93
Subtransmission	\$13.38	0.954	\$12.75	-7.890	4.86	\$ 8.46	\$ 9.64
Transmission	\$13.38	0.940	\$12.57	-7.890	4.68	\$ 8.28	\$ 9.43
Proposed Demand Revenue	Billing Demand	Proposed Rate	Demand Revenue				
Secondary	1,117,380	\$15.76	\$17,614,107				
Primary	288,303	\$13.93	4,016,059				
Subtransmission	16,692	\$9.64	160,844				
Transmission	5,360	\$9.43	50,554				
Total	1,427,736		\$21,841,564				

Kentucky Power Company  
LGS Rate Design  
Twelve Months Ended May 31, 2025

VI. Proposed Energy Charges and Revenue

	Billing Energy	Loss Factor	Loss Adj Energy
Loss Adjusted Energy			
Secondary	368,420,987	1.000	368,420,987
Primary	84,822,808	0.955	80,974,926
Subtransmission	6,934,309	0.941	6,524,183
Transmission	1,436,000	0.929	1,334,356
Total	461,614,105		457,254,452
Equipment Credit Revenue	Billing Energy	60% of Equipment Credit	Equipment Credit Revenue
Secondary	368,420,987	--	0
Primary	84,822,808	(0.00425)	(360,497)
Subtransmission	6,934,309	(0.01646)	(114,139)
Transmission	1,436,000	(0.01646)	(23,637)
Total	461,614,105		(\$498,273)
Total Revenue	\$69,296,155		
Less: Customer Revenue	849,912		
Excess KVA Revenue	369,419		
Demand Revenue	21,841,564		
EDR Credit	-35,483		
Equipment Credit Revenue	(498,273)		
Energy Revenue	\$46,769,016		
Loss Adjusted Billing Energy	457,254,452		
Secondary Energy Charge	\$0.10228	Energy Rate Mitigation	0

	Secondary Rate	Loss Factor	Energy Rate	Equipment Credit	Mitigation	Proposed Rate	Current Rate	
Secondary	\$0.10228	1.000	\$0.10228	0.00000	0.00010	\$0.10238	0.08966	14%
Primary	0.10228	0.955	\$0.09764	(0.00425)		\$0.09339	0.08120	15%
Subtransmission	0.10228	0.941	\$0.09623	(0.01646)	-0.00850	\$0.07127	0.06292	13%
Transmission	0.10228	0.929	\$0.09504	(0.01646)	-0.00850	\$0.07008	0.06198	13%

VII. LGS Total Revenue Verification

		Units	Rate	Revenue
Secondary	Demand	1,117,380 kW	\$15.76 /kW	\$17,614,107
	Excess KVA	49,523 KVA	3.46 /KVA	171,349
	Energy	368,420,987 kWh	0.10238 /kWh	37,718,941
	Customer	5,772 Bills	111.00 /Mo	640,692
	Total Billed			\$56,145,089
Primary	Demand	288,303 kW	\$13.93 /kW	\$4,016,059
	Excess KVA	53,997 KVA	3.46 /KVA	186,830
	Energy	84,822,808 kWh	0.09339 /kWh	7,921,602
	EDR Credit			0
	Customer	708 Bills	166.00 /Mo	117,528
	Total Billed			\$12,242,019
Subtran	Demand	16,692 kW	\$9.64 /kW	\$160,844
	Excess KVA	3,249 KVA	3.46 /KVA	11,240
	Energy	6,934,309 kWh	0.07127 /kWh	494,208
	Customer	84 Bills	849.00 /Mo	71,316
	Total Billed			\$737,608
Tran	Demand	5,360 kW	\$9.43 /kW	\$50,554
	Excess KVA	0 KVA	3.46 /KVA	0
	Energy	1,436,000 kWh	0.07008 /kWh	100,635
	Customer	24 Bills	849.00 /Mo	20,376
	Total Billed			\$171,565
Total Tariff LGS				\$69,296,281
Target				\$69,296,155
Difference				\$126
				\$0.000000



Kentucky Power Company  
LGS Rate Design  
Twelve Months Ended May 31, 2025

VIII. Off-Peak Energy Charge For LM-TOD

Secondary Energy Revenue Reqt	\$17,436,093	/	374,091,952 kwh	=	\$0.04661
Fixed Cost Adder					<u>0.05016</u>
Calculated Off-Peak Energy Charge					\$0.09677
Use:					\$0.09677
Off-Peak % Usage - Secondary					48.17%
Off-Peak kWh					<u>180,218,212</u>
Off-Peak Revenue					\$17,439,716

IX. On-Peak Energy Charge

Total LGS Secondary Base Revenue	\$57,469,310
Less: Customer Revenue	640,692
Time-of-Day Customer Revenue	13,320
Off-Peak Energy Revenue	<u>17,439,716</u>
On-Peak Revenue	\$39,375,582
On-Peak kWh Energy	<u>193,873,740</u>
Proposed On-Peak Energy Charge	\$0.20310 /kWh

X. Revenue Verification

	<u>Units</u>	<u>Rate</u>	<u>Revenue</u>	<u>Difference</u>
On-Peak	193,873,740 kWh	\$0.20310 /kWh	\$39,375,757	
Off-Peak	180,218,212 kWh	\$0.09677 /kWh	17,439,716	
Customer - Standard	5,772 Bills	\$111.00 /Mo	640,692	
- Time-of-Day	120 Bills	\$111.00 /Mo	13,320	
Total Base Revenue			\$57,469,485	\$175

XI. Revenue From Existing TOD Customers

	<u>Units</u>	<u>Rate</u>	<u>Proposed Revenue</u>
<u>LGS-LM-TOD</u>			
On-Peak Energy	368,610 kWh	\$0.20310 /kWh	\$74,865
Off-Peak Energy	510,345 kWh	\$0.09677 /kWh	49,386
Customer	60 Bills	\$111.00 /Mo *	<u>6,660</u>
			\$130,911
<u>LGS TOD SEC</u>			
On-Peak Energy	2,053,648 kWh	\$0.14753	\$ 302,975
Off-Peak Energy	2,738,362 kWh	\$0.07170	\$ 196,341
Billing demand	9,958 kW	\$13.10	\$ 130,453
Excess kVa	76 kVa	\$3.46	\$ 263
Customer	60 Bills	\$111.00	<u>\$ 6,660</u>
			\$ 636,691
<u>LGS TOD Primary</u>			
On-Peak Energy	1,416,068 kWh	\$0.14084	\$ 199,439
Off-Peak Energy	1,994,033 kWh	\$0.06958	\$ 138,745
Billing demand	5,320 kW	\$10.78	\$ 57,353
Excess kVa	4,265 kVa	\$3.46	\$ 14,757
Customer	24 Bills	\$166.00	<u>\$ 3,984</u>
Total			\$ 414,278

\*Use same as standard and TOD

\$1,181,880

Kentucky Power Company  
LGS TOD Rate Design  
Twelve Months Ended May 31, 2025

I. Proposed Revenue

	<u>Secondary</u>	<u>Primary</u>	<u>Subtran</u>	<u>Trans</u>
<u>Proposed Base Revenue</u>				
Demand	\$39,375,847	\$7,943,142	\$445,004	\$63,739
Energy	17,436,093	3,865,978	296,431	133,492
Customer	<u>657,370</u>	<u>169,047</u>	<u>71,313</u>	<u>20,580</u>
Total Base Revenue	\$57,469,310	\$11,978,167	\$812,748	\$217,811

II. Customer Revenue

Full Cost Customer Revenue	\$657,370	\$169,047	\$71,313	\$20,580
All Bills	<u>5,832</u>	<u>708</u>	<u>84</u>	<u>24</u>
Calculated Customer Charge	\$112.72	\$238.77	\$848.96	\$857.50
Proposed Customer Charge	\$111.00	\$166.00	\$849.00	\$849.00
All Bills	<u>5,832</u>	<u>708</u>	<u>84</u>	<u>24</u>
Proposed Customer Revenue	\$ 647,352	\$ 117,528	\$ 71,316	\$ 20,376

III. Off-Peak Energy Charge

	<u>Secondary</u>	<u>Primary</u>	<u>Subtran</u>	<u>Trans</u>	<u>Total</u>
Energy Revenue Requirement	\$17,436,093	\$3,865,978	\$296,431	\$133,492	\$21,731,995
Total Billing kWh	374,091,952	88,232,909	6,934,309	1,436,000	
Loss Factor	1.000	0.955	0.941	0.929	
Loss Adjusted Energy	374,091,952	84,230,332	6,524,183	1,334,356	466,180,824
Total Energy Charge	\$0.04662	\$0.04450	\$0.04386	\$0.04332	\$0.04662
Fixed Cost Adder	\$0.02508	\$0.02508	\$0.02508	\$0.02508	
Calculated Off-Peak Energy Charge	\$0.07170	\$0.06958	\$0.06894	\$0.06840	
Proposed Off-Peak Energy Charge	\$0.07170	\$0.06958	\$0.06894	\$0.06840	
Off-Peak % Usage	48.17%	48.27%	48.25%	49.20%	
Off-Peak kWh	180,218,212	42,586,925	3,345,677	706,520	
Proposed Off-Peak Charge	<u>\$0.07170</u>	<u>\$0.06958</u>	<u>\$0.06894</u>	<u>\$0.06840</u>	
Off-Peak Revenue	\$12,921,646	\$2,963,198	\$230,651	\$48,326	

Kentucky Power Company  
LGS TOD Rate Design  
Twelve Months Ended May 31, 2025

IV. Demand Charge

	Billing Demand	Proposed Rate *	Demand Revenue
LGS - Secondary	1,117,380	13.10	\$14,637,675
- Primary	288,303	10.78	3,107,911
- Subtransmission	16,692	4.97	82,960
- Transmission	5,360	4.90	26,266
Total			\$17,854,812

\* Full cost off-peak rates

V. On-Peak Energy Charge

	<u>Secondary</u>	<u>Primary</u>	<u>Subtran</u>	<u>Trans</u>	<u>Total</u>
Total Revenue	\$57,469,310	\$11,978,167	\$812,748	\$217,811	
Less: Customer Revenue	647,352	117,528	71,316	20,376	
Demand Revenue	14,637,675	3,107,911	82,960	0	
Off-Peak Energy Revenue	12,921,646	2,963,198	230,651	48,326	
On-Peak Revenue	\$29,262,636	\$5,789,529	\$427,821	\$149,109	\$35,629,096
On-Peak kWh	193,873,740	45,645,984	3,588,632	729,480	
Loss Factor	1.000	0.955	0.941	0.929	
Loss Adjusted Energy	193,873,740	43,575,310	3,376,384	677,845	241,503,281
Calculated On-Peak Energy Charge	\$0.14753	\$0.14084	\$0.13880	\$0.13709	\$0.14753
Proposed On-Peak Energy Charge	\$0.14753	\$0.14084	\$0.13880	\$0.13709	
On-Peak kWh	193,873,740	45,645,984	3,588,632	729,480	
On-Peak Revenue	\$28,602,193	\$6,428,780	\$498,102	\$100,004	\$35,629,079

Kentucky Power Company  
IGS Rate Design  
Twelve Months Ended May 31, 2025

I. Proposed Revenue

	<u>Base Revenue</u>
Demand	\$86,910,496
Energy	94,471,159
Customer	<u>262,430</u>
Total	\$181,644,085

II. Billing Determinant Summary

<b>Billing Data</b>	<u>Secondary</u>	<u>Primary</u>	<u>Subtransmission</u>	<u>Transmission</u>
On-Peak Billing Demand	30,814	548,973	2,658,196	462,663
Off-Peak Billing Demand	29,884	435,784	2,549,482	411,874
Minimum Billing Demand	16,523	63,650	61,565	9,165
Maximum Monthly Demand kW	47,337	612,623	2,719,761	471,828
Billing Reactive	161	132,892	132,583	67,907
Billing kWh	19,599,840	236,711,440	1,654,916,002	271,811,000
Bills	60	408	204	36

III. Proposed Customer Charges & Revenue

Proposed Customer Charge	<u>Customer Revenue</u>	<u>Bills</u>	<u>Full Cost Rate</u>	<u>Use: Current Rate</u>
Secondary	4,843	60	\$80.72	\$276
Primary	75,371	408	\$184.73	\$276
Subtransmission	145,850	204	\$714.95	\$794
Transmission	<u>36,366</u>	<u>36</u>	<u>\$1,010.17</u>	<u>\$1,353</u>
Total	\$262,430	708		

Proposed Customer Revenue	<u>Proposed Rate</u>	<u>Bills</u>	<u>Customer Revenue</u>
Secondary	\$276	60	16,560
Primary	\$276	408	112,608
Subtransmission	\$794	204	161,976
Transmission	<u>\$1,353</u>	<u>36</u>	<u>48,708</u>
Total		708	\$339,852

IV. Proposed Excess KVAR Charges & Revenue

Proposed KVAR Revenue	<u>Use: Current Excess KVAR Rate</u>	<u>Excess KVAR</u>	<u>Revenue</u>
Secondary	\$0.69	161	111
Primary	\$0.69	132,892	91,695
Subtransmission	\$0.69	132,583	91,482
Transmission	<u>\$0.69</u>	<u>67,907</u>	<u>46,856</u>
Total		333,543	\$230,144

V. Proposed Off-Peak Demand Charges and Revenue

	<u>Off-peak Demand</u>	linked <u>Proposed Rate</u>	<u>Revenue</u>
Secondary	29,884	\$2.08	62,159
Primary	435,784	\$2.01	875,926
Subtransmission	2,549,482	\$1.98	5,047,974
Transmission	<u>411,874</u>	<u>\$1.96</u>	<u>807,274</u>
Total	3,427,024		\$6,793,333

Kentucky Power Company  
IGS Rate Design  
Twelve Months Ended May 31, 2025

VI. Proposed Energy Charges and Revenue

	<u>Billing Energy</u>	<u>Loss Factor</u>	<u>Loss Adj Energy</u>
Loss Adjusted Energy			
Secondary	19,599,840	1.000	19,599,840
Primary	236,711,440	0.955	225,973,319
Subtransmission	1,654,916,002	0.941	1,557,036,871
Transmission	271,811,000	0.929	252,571,477
Total	2,183,038,282		2,055,181,507
Energy Revenue	\$94,471,159		
Loss Adjusted Billing Energy	2,055,181,507		
Secondary Energy Charge	\$0.04597		
Impact mitigation	-0.00060		
Adjusted Secondary Energy Charge	\$0.04537		
	<u>Secondary Rate</u>	<u>Loss Factor</u>	<u>Calculated Energy Rate</u>
Secondary	\$0.04537	1.000	\$0.04537
Primary	0.04537	0.955	\$0.04331
Subtransmission	0.04537	0.941	\$0.04269
Transmission	0.04537	0.929	\$0.04216
			<u>Current Base Fuel Rate</u>
Secondary			0.03380
Primary			0.03380
Subtransmission			0.03380
Transmission			0.03380

Proposed Energy Revenue

	<u>Billing Energy</u>	<u>Proposed Rate</u>	<u>Revenue</u>
Secondary	19,599,840	\$0.04537	889,245
Primary	236,711,440	\$0.04331	10,251,972
Subtransmission	1,654,916,002	\$0.04269	70,648,364
Transmission	271,811,000	\$0.04216	11,459,552
Total	2,183,038,282		\$93,249,133

VII. Proposed Minimum Demand Charges and Revenue

	<u>Maximum Demand</u>	<u>Loss Factor</u>	<u>Loss Adj Demand</u>
Calculation of Loss Adj Demand			
Secondary	47,337	1.000	47,337
Primary	612,623	0.967	592,525
Subtransmission	2,719,761	0.954	2,593,448
Transmission	471,828	0.940	443,563
Total	3,851,549		3,676,873

	<u>Maximum Demand</u>	<u>Equipment Credit</u>	<u>Credit Revenue</u>
Equipment Credit Revenue			
Secondary	47,337	0.00	\$0
Primary	612,623	(1.96)	(\$1,200,740)
Subtransmission	2,719,761	(7.89)	(\$21,458,917)
Transmission	471,828	(7.89)	(\$3,722,724)
Total	3,851,549		(\$26,382,381)

Total Required Demand Revenue	\$86,910,496
Less: Equipment Credit Revenue	(26,382,381)
Demand Revenue	\$113,292,877
Loss Adjusted Maximum Demand	3,676,873
Full Cost Demand Charge	\$30.81

	<u>Secondary Rate</u>	<u>Loss Factor</u>	<u>Demand Rate</u>	<u>Equipment Credit</u>	<u>Proposed Rate</u>	<u>Mitigation After Rate Calculation</u>	<u>Proposed Rate</u>
Demand Charges							
Secondary	\$30.81	1.000	\$30.81	0.00	\$30.81	\$1.10	\$30.52
Primary	\$30.81	0.967	\$29.80	(1.96)	\$27.84	\$1.84	\$28.33
Subtransmission	\$30.81	0.954	\$29.38	(7.89)	\$21.49	-\$0.61	\$19.55
Transmission	\$30.81	0.940	\$28.96	(7.89)	\$21.07	-\$0.61	\$19.16

Proposed Minimum Demand Revenue

	<u>Minimum Demand</u>	<u>Proposed Rate</u>	<u>Current Rate</u>	<u>Revenue</u>
Secondary	16,523	\$31.91	\$25.68	424,311
Primary	63,650	\$29.68	\$23.68	1,507,225
Subtransmission	61,565	\$20.88	\$16.12	992,431
Transmission	9,165	\$20.46	\$15.77	144,532
Total	150,903			\$3,068,499

Kentucky Power Company  
IGS Rate Design  
Twelve Months Ended May 31, 2025

VII. Proposed On-Peak Demand Charges and Revenue

	Billing Demand	Loss Factor	Loss Adj Demand
Calculation of Loss Adj Demand			
Secondary	30,814	1.000	30,814
Primary	548,973	0.967	530,963
Subtransmission	2,658,196	0.954	2,534,742
Transmission	462,663	0.940	434,947
Total	3,700,646		3,531,466

	Billing Demand	Equipment Credit	Credit Revenue
Equipment Credit Revenue			
Secondary	30,814	0.00	\$0
Primary	548,973	(1.96)	(\$1,075,987)
Subtransmission	2,658,196	(7.89)	(\$20,973,167)
Transmission	462,663	(7.89)	(\$3,650,412)
Total	3,700,646		(\$25,699,566)

Total Required Base Revenue	\$181,644,085
Less: Customer Revenue	\$339,852
Excess KVAR Revenue	230,144
Off-peak Revenue	6,793,333
CS-IRP Credit Revenue	-628,135
EDR/DRS Credit Revenue	-4,054,512
Energy Revenue	93,249,133
Minimum Demand Revenue	3,068,499
Special Contract Billing	4,438,288
Equipment Credit Revenue	(25,699,566)

Demand Revenue	\$103,907,049
Loss Adjusted Billing Demand	3,531,466

Full Cost Demand Charge	\$29.42
% of Full Cost	100%

	Secondary Rate	Loss Factor	Demand Rate	Equipment Credit	Proposed Rate	Mitigation After Rate Calculation	Current Rate	
Demand Charges								
Secondary	\$29.42	1.000	\$29.42	0.00	\$29.42	1.1	26.99	12.0%
Primary	\$29.42	0.967	\$28.45	(1.96)	\$26.49	1.84	24.94	12.8%
Subtransmission	\$29.42	0.954	\$28.05	(7.89)	\$20.16	-0.61	17.36	10.9%
Transmission	\$29.42	0.940	\$27.66	(7.89)	\$19.77	-0.61	17	10.9%

Proposed On-Peak Demand Revenue

	On-Peak Demand	Proposed Rate	Revenue
Secondary	30,814	\$30.52	940,443
Primary	548,973	\$28.33	15,552,400
Subtransmission	2,658,196	\$19.55	51,967,733
Transmission	462,663	\$19.16	8,864,624
Total	3,700,646		\$77,325,200

Kentucky Power Company  
IGS Rate Design  
Twelve Months Ended May 31, 2025

VIII. Revenue Verification		<u>Units</u>	<u>Rate</u>	<u>Revenue</u>	<u>Target</u>	<u>Difference</u>	<u>Current rates</u>	
Secondary	On-Peak Demand	30,814 kW	\$30.52 /kW	\$940,443			26.99	13%
	Off-peak Demand	29,884 kW	2.08 /kW	62,159			1.84	
	Minimum Demand	16,523 kW	31.91 /kW	527,249				
	Excess KVAR	161 KVAR	0.69 /KVAR	111				
	Energy	19,599,840 kWh	0.04537 /kWh	889,245			0.03924	16%
	Customer	60 Bills	276.00 /Mo	16,560			276	
	Total Billed			\$2,435,767	\$ 2,097,265	14%		
Primary	On-Peak Demand	548,973 kW	\$28.33 /kW	\$15,552,400			24.94	14%
	Off-peak Demand	435,784 kW	2.01 /kW	875,926			1.78	
	Minimum Demand	63,650 kW	29.68 /kW	1,889,123				
	CS-IRP Demand Credit	54,571	-3.68 /kW	-200,821				
	EDR			-56,125				
	Excess KVAR	132,892 KVAR	0.69 /KVAR	91,695				
	Energy	236,711,440 kWh	0.04331 /kWh	10,251,972			0.03775	15%
	Customer	408 Bills	276.00 /Mo	112,608			276	
	Total Billed			\$28,516,778	\$ 22,716,136	20%		
Subtran	On-Peak Demand	2,658,196 kW	\$19.55 /kW	\$51,967,733			17.36	13%
	Off-peak Demand	2,549,482 kW	1.98 /kW	5,047,974			1.75	
	Minimum Demand	61,565 kW	20.88 /kW	1,285,482				
	CS-IRP Demand Credit	83,724	-3.68 /kW	-308,104				
	EDR/DRS/Special Billing			501,216				
	Excess KVAR	132,583 KVAR	0.69 /KVAR	91,482				
	Energy	1,654,916,002 kWh	0.04269 /kWh	70,648,364			0.03732	14%
	Customer	204 Bills	794.00 /Mo	161,976			794	
	Total Billed			\$129,396,123	\$ 134,861,700	-4%		
Tran	On-Peak Demand	462,663 kW	\$19.16 /kW	\$8,864,624			17	13%
	Off-peak Demand	411,874 kW	1.96 /kW	807,274			1.73	
	Minimum Demand	9,165 kW	20.46 /kW	187,516				
	CS-IRP Demand Credit	32,394	-3.68 /kW	-119,210				
	Excess KVAR	67,907 KVAR	0.69 /KVAR	46,856				
	Energy	271,811,000 kWh	0.04216 /kWh	11,459,552			0.03695	14%
	Customer	36 Bills	1,353.00 /Mo	48,708			1353	
	Total Billed			\$21,295,320	\$ 21,968,984	-3%		
Total Tariff IGS			Base	\$181,643,988	\$ 181,644,085	0%		
revenue target				\$181,644,085	(\$97)		(0.00)	

Kentucky Power Company  
MW Rate Design  
Twelve Months Ended May 31, 2025

Kentucky Power Company  
MW Rate Design  
Twelve Months Ended May 31, 2025

I. Revenue	Billed & Accrued Revenue	Fuel	Base Revenue
Demand	159,475	0	159,475
Energy	88,514	0	88,514
Customer	10,743	0	10,743
Total	258,732	0	258,732

II. Customer Charge							
Full Cost Customer Charge	\$	10,743	/	96	bills	\$ 111.91 /mo.	Overall % increase
					Current:	\$ 25.00 /mo.	11.50%
					Proposed	\$ 28.00	
Customer Revenue		96	Bills	X	\$28.00 /mo.	\$ 2,688	

III. Demand Charge	
Demand Revenue Requirement	\$ 159,475
Monthly Demand (SNCP)	3,822
Full Cost Demand Charge	41.72
Current Minimum Demand Charges	9.55
Class Increase	7.00%
Proposed Minimum Demand Charge	10.22
Minimum kW	-
Minimum Demand Charge Revenue	\$ -

IV. Energy Charge	
Energy Revenue Requirement	
Total MW Revenue Requirement	\$ 258,732
Less: Customer Revenue	2,688
Less: Minimum Demand Revenue	-
Energy Charge Revenue	\$ 256,044
Billing kWh	1,831,694
Proposed Energy Charge	0.13979

V. Revenue Verification	Units	Proposed Charges	Revenue	Target Revenue	Difference
Energy	1,831,694	\$0.13979	256,053		
Demand	-	\$10.22	-		
Customer	96	\$28.00	2,688		
Total MW Verified Revenues			258,741	258,732	9



\* In process of elimination (Overall Increase)

Kentucky Power Company  
OL Rate Design  
Twelve Months Ended May 31, 2025

Lamp Type & Size (1)	Estimated Installed Cost (2)	Monthly Facility Cost (3)=(2)*FCCR	Annual Maintenance Cost (4)	Consumption in kWh		Energy Cost no Fuel @ \$0.08523 per kWh (7)=(6)*EC	Estimated Monthly Maintenance (8)	Lighting Cost Estimate (9)=(3+7+8)
				Annual (5)	Monthly (6)			
<b>High Pressure Sodium (HPS)</b>								
100 Watt	\$283.12	\$4.19	\$30.01	484	40.3	\$4.49	\$2.50	\$11.18
150 Watt	\$280.86	\$4.16	\$29.55	704	58.7	\$6.54	\$2.46	\$13.16
200 Watt	\$321.65	\$4.76	\$29.65	1,012	84.3	\$9.39	\$2.47	\$16.62
250 Watt	\$529.31	\$7.83	\$29.53	1,236	103.0	\$11.47	\$2.46	\$21.76
400 Watt	\$405.63	\$6.00	\$29.96	2,000	166.7	\$18.56	\$2.50	\$27.06
100 Watt Post Top	\$1,572.06	\$23.27	\$29.24	484	40.3	\$4.49	\$2.44	\$30.20
150 Watt Post Top	\$1,573.64	\$23.29	\$29.55	704	58.7	\$6.54	\$2.46	\$32.29
200 Watt Floodlight	\$471.29	\$6.98	\$29.65	1,012	84.3	\$9.39	\$2.47	\$18.84
400 Watt Floodlight	\$503.05	\$7.45	\$29.96	2,000	166.7	\$18.56	\$2.50	\$28.51
100 Watt Shoebox	\$1,728.32	\$25.58	\$29.24	484	40.3	\$4.49	\$2.44	\$32.51
250 Watt Shoebox	\$1,751.27	\$25.92	\$29.53	1,236	103.0	\$11.47	\$2.46	\$39.85
400 Watt Shoebox	\$1,767.70	\$26.16	\$29.96	2,000	166.7	\$18.56	\$2.50	\$47.22
<b>Metal Halide</b>								
250 Watt Floodlight	\$530.46	\$7.85	\$31.88	1,204	100.3	\$11.17	\$2.66	\$21.68
400 Watt Floodlight	\$547.40	\$8.10	\$32.48	1,896	158.0	\$17.59	\$2.71	\$28.40
1000 Watt Floodlight	\$696.51	\$10.31	\$31.75	4,540	378.3	\$42.12	\$2.65	\$55.08
250 Watt Mongoose	\$903.89	\$13.38	\$31.88	1,204	100.3	\$11.17	\$2.66	\$27.21
400 Watt Mongoose	\$922.89	\$13.66	\$32.48	1,896	158.0	\$17.59	\$2.71	\$33.96
						Flex Lighting	\$2.53	
Fixed Cost CC Rate Using 10-Yr Inv Life				<b>Outdoor Lighting (OL) Cost of Service</b>				
Return	7.57%			Demand Revenue Requirement		\$749,014		
Depreciation	8.21%			Energy Revenue Requirement		\$1,588,739		
F.I.T.	0.60%			<u>Cust. Related Revenue Req't.</u>				
Prop Taxes, Adm & Gen'l	1.40%			O&M Expenses		\$845,097		
Annual Total	17.78%			Taxes Other		\$276,836		
				State Income Tax		-\$1,621		
				Less: Acct. 598		\$27,519		
Monthly Total FCCRR	1.48%			B&A Rev Excl Direct Ltg Costs		\$3,430,545		
				Class Metered Energy		30,809,971		
				Energy Rate (\$/kWh)		\$0.11135		

Kentucky Power Company  
OL Rate Design  
Twelve Months Ended May 31, 2025

Facilities Charges

	Installed		
	Cost	Carrying Charge	
30ft Wood Pole	549.25	1.48%	8.13
35ft Wood Pole	852.97	1.48%	12.62
Average			<u>10.38</u>
OH Span - Total - <= 150 ft.	150.28	1.48%	2.22
UG Lateral - 50 Feet	524.89	1.48%	7.77

Lamp Type & Size (1)	Annual	Present		Cost Based		scaled	Proposed		Annual	Percent	Monthly kWh	Base Fuel Revenue 0.02612	Non-Fuel Base Rate
	Number of	Rate	Revenue	Lamp	Lamp	Rate	Revenue	Increase	Increase				
	Lamps (2)	(3)	(4)=(2*3)	(5)	w/pole (6)	(7)	(8)=(2*7)	(9)	(10)=(8/4)				
<b><u>Service on Existing Wood Poles</u></b>													
9,500 Lumen HPS	76,407	\$8.64	660,156	8.81	n.a.	\$10.02	765,598	105,442	15.97%		40.3	1.05	\$10.02
16,000 Lumen HPS	1,107	\$9.49	10,505	9.99	n.a.	\$11.00	12,177	1,672	15.91%		58.7	1.53	\$11.00
22,000 Lumen HPS	3,541	\$11.24	39,801	12.08	n.a.	\$13.03	46,139	6,338	15.93%		84.3	2.2	\$13.03
50,000 Lumen HPS	5,331	\$14.76	78,686	17.49	n.a.	\$17.11	91,213	12,527	15.92%		166.7	4.35	\$17.11
LED - 8,000-11,000 Lumens	39,740	\$9.89	393,029			\$11.47	455,818	62,789	15.98%		27.75	0.72	\$11.47
LED - 10,000-14,000 Lumens	1,532	\$12.70	19,456			\$14.72	22,551	3,095	15.91%		38.17	1	\$14.72
LED - 24,000-30,000 Lumens	1,294	\$15.14	19,591			\$17.55	22,710	3,119	15.92%		77.92	2.04	\$17.55
Post Top 6,000-10,000 Lumens	1,188	\$10.27	12,201			\$11.91	14,149	1,948	15.97%		26.42	0.69	\$11.91
Post Top 8,000-12,000 Lumens	12	\$22.78	273			\$26.41	317	44	15.94%		38.167	1	\$26.41
Flood 17,500-22,500 Lumens	24	\$16.67	400			\$19.33	464	64	15.96%		59.667	1.56	\$19.33
<b><u>Service on New Wood Poles</u></b>													
9,500 Lumen HPS	5,025	\$13.51	67,888	8.81	15.05	\$15.66	78,692	10,804	15.91%		40.3	1.05	\$15.66
16,000 Lumen HPS	267	\$14.47	3,863	9.99	16.19	\$16.78	4,480	617	15.96%		58.7	1.53	\$16.78
22,000 Lumen HPS	6,833	\$16.23	110,900	12.08	18.22	\$18.82	128,597	17,697	15.96%		84.3	2.2	\$18.82
50,000 Lumen HPS	480	\$20.83	9,998	17.49	23.43	\$24.15	11,592	1,594	15.94%		166.7	4.35	\$24.15
LED - 8,000-11,000 Lumens	214	\$16.30				\$18.90	4,045	4,045	15.95%		27.75	0.72	\$18.90
LED - 10,000-14,000 Lumens	-	\$19.12				\$22.17	0	0	15.95%		38.17	1	\$22.17
LED - 24,000-30,000 Lumens	24	\$21.57				\$25.01	600	600	15.95%		77.92	2.04	\$25.01
Post Top 6,000-10,000 Lumens	-	\$16.68				\$19.34	0	0	15.95%		26.42	0.69	\$19.34
Post Top 8,000-12,000 Lumens	-	\$29.20				\$33.85	0	0	15.92%		38.17	1	\$33.85
Flood 17,500-22,500 Lumens	-	\$23.10				\$26.78	0	0	15.93%		59.67	1.56	\$26.78
<b><u>Service on New Metal or Concrete Poles</u></b>													
9,500 Lumen HPS	-	\$28.15	0	8.81	28.19	\$32.63	0	0	15.91%		40.3	1.05	\$32.63
16,000 Lumen HPS	-	\$29.17	0	9.99	29.34	\$33.82	0	0	15.94%		58.7	1.53	\$33.82
22,000 Lumen HPS	1,080	\$30.93	33,404	12.08	31.36	\$35.86	38,729	5,325	15.94%		84.3	2.2	\$35.86
50,000 Lumen HPS	893	\$34.45	30,764	17.49	36.57	\$39.94	35,666	4,902	15.94%		166.7	4.35	\$39.94
LED - 8,000-11,000 Lumens	-	\$28.49	0			\$33.03	0	0	15.94%		27.75	0.72	\$33.03
LED - 10,000-14,000 Lumens	-	\$30.40	0			\$35.24	0	0	15.92%		38.17	1	\$35.24
LED - 24,000-30,000 Lumens	24	\$31.90	766			\$36.98	888	122	15.92%		77.92	2.04	\$36.98
Post Top 6,000-10,000 Lumens	-	\$29.34	0			\$34.01	0	0	15.92%		26.42	0.69	\$34.01
Post Top 8,000-12,000 Lumens	-	\$41.70	0			\$48.34	0	0	15.92%		38.17	1	\$48.34
Flood 17,500-22,500 Lumens	-	\$33.39	0			\$38.71	0	0	15.93%		59.67	1.56	\$38.71
											0		\$0.00
Subtotal							\$1,734,425	\$242,744					
Base Fuel							\$264,890						
Total							\$1,999,315						
Revenue Target							\$1,999,164						
Difference							\$151						
Class Increase		11.8%											
Maximum Increase (1.5 x class increase)		15.93%											
Scale Factor		1.0000											

FCCRR 20-Yr Inv Life		Street Lighting (SL) Cost of Service	
Return	7.57%	Demand-Related Revenue Reqmt	\$196,068
Depreciation	3.36%	Energy-Related Revenue Reqmt	362,410
F.I.T.	0.73%	<u>Customer-Related Revenue Requirement</u>	
Prop Taxes, Adm & Gen'l	1.40%	O&M Expenses	120,452
Annual Total	13.06%	Taxes Other	44,711
		State Income Tax	-166
		Less: Account 585	32,865
Monthly Total FCCRR	1.09%	Account 596	7,679
		B&A Rev Excl Direct Ltg Cost	\$682,932
		Class Metered Energy	7,836,986
		Energy Rate (\$/kWh)	\$0.08714

Kentucky Power Company  
AFS Rate Design  
Twelve Months Ended May 31, 2025

**AFS Monthly Cost / Reservation Demand Charge**

Primary Demand & Customer Revenue Requirement		\$26,911,587
Functional Demand kW @ Secondary	/	\$4,539,506
Monthly Cost @ Secondary	=	\$5.93
Loss Factor Secondary to Primary	x	0.96719426
AFS Monthly Cost @ Primary	=	<b>\$5.73</b>
Proposed Rate (same as current)	=	<b>\$6.38</b> \$/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	=	<b>\$15.75</b> \$/bill

Kentucky Power Company  
Full Cost Off-Peak Demand Charges  
Twelve Months Ended May 31, 2025

	Demand Loss <u>Factors</u>	<u>Production</u>	Full Cost <u>Charges</u>
Functional Demand Cost		20.83	
Off-Peak Recovery %		10%	
Off Peak Demand Cost		2.08	
Secondary Charge	1.000	2.08	\$2.08
Primary Charge	0.967	2.01	\$2.01
Subtran Charge	0.954	1.98	\$1.98
Transmission Charge	0.940	1.96	\$1.96

Kentucky Power Company  
Equipment Credits Relative to Secondary  
Twelve Months Ended May 31, 2025

<u>Current Energy Summary</u>	Secondary	Primary	Subtran	Bulk Tran	Production
GS	611,430,417	7,303,315	187,943		
LGS and PS	374,091,952	88,232,909	6,934,309	1,436,000	
IGS	19,599,840	236,711,440	1,765,268,003	271,811,000	
Total	1,005,122,209	332,247,664	1,772,390,255	273,247,000	
Relative Loss Factor	1.00000	0.95464	0.94086	0.92922	
Loss Adj Energy	1,005,122,209	317,175,660	1,667,563,172	253,905,833	
	71.8%	71.8%			
Energy Served by Subtran Sys	721,688,428	227,735,495	1,667,563,172		
Functional Demand Rev	7,128,874	26,911,587	0	0	158,260,243
Functional Energy	1,005,122,209	1,322,297,869	2,616,987,095	3,243,766,874	3,243,766,874
Functional Cost	0.00709	0.02035	0.00000	0.00000	0.04879

Full Cost Equipment Credits

	Secondary	Primary	Subtran	Total	
Primary	0.00709			0.00709	-0.00709
Subtransmission	0.00709	0.02035		0.02744	-0.02744
Transmission	0.00709	0.02035	0.00000	0.02744	-0.02744

TOD and AF Energy

	Metered kWh
LGS-Sec and PS-Sec	368,420,987
LGS-LM-TOD	878,955
LGS-TOD	<u>4,792,010</u>
Total LGS-Sec	374,091,952



Kentucky Power Company  
Equipment Credits Relative to Secondary  
Twelve Months Ended May 31, 2025

<u>Current Billing Demand Summary</u>	SNCP Total LR			Bulk Tran	Production
	Secondary	Primary	Subtran		
GS	2,457,796	28,798	737		
LGS and PS	1,130,004	293,624	16,692	5,360	
IGS	47,337	612,623	2,719,761	471,828	
Total	3,635,137	935,044	2,737,190	477,189	
Relative Loss Factor	1.00000	0.96719	0.95356	0.94009	
Loss Adj Demand	3,635,137	904,369	2,610,067	448,602	
	71.80%	71.80%			
Demand Served by Subtran System	2,610,067	649,347	2,610,067		
Functional Demand Rev	7,128,874	26,911,587	0	0	158,260,243
Functional Demand	3,635,137	4,539,506	5,869,481	7,598,175	7,598,175
Functional Cost	1.96	5.93	0.00	0.00	20.83

Full Cost Equipment Credits (Relative to Secondary)

	Secondary	Primary	Subtran	Total	
Primary	1.96			<b>1.96</b>	-1.96
Subtransmission	1.96	5.93		<b>7.89</b>	-7.89
Transmission	1.96	5.93	0.00	<b>7.89</b>	-7.89

TOD and AF Demands

	Standard		Other	
	Metered kWh	Billing Demand	Metered kWh	Billing Demand
GS-Sec (211,215, 218)	591,442,417	2,377,450		
SGS TOD (227)		GS SEC SNCP LR	7,320,966	29,428
GS AF (214)			1,299,575	5,224
MGS TOD (229)			7,251,724	29,150
GS LMTOD (223,225)			1,499,357	6,027
GS NM (213)			2,616,378	10,517
LGS-Sec	368,420,987	1,117,380		
LGS-LM-TOD			878,955	2,666
LGS TOD	4,792,010	9,958		

Kentucky Power Company  
Full Cost Off-Peak Excess  
Twelve Months Ended May 31, 2025

	Demand Loss <u>Factors</u>	<u>Distribution</u>		<u>Subtran</u>	Bulk <u>Tran</u>	<u>Production</u>	Full Cost <u>Charges</u>
		<u>Secondary</u>	<u>Primary</u>				
Functional Demand Cost		1.96	5.93	0.00	0.00	20.83	
Off-Peak Recovery %		100%	100%	25%	25%	25%	
Off Peak Demand Cost		1.96	5.93	0.00	0.00	5.21	
Secondary Charge	1.000	1.96	5.93	0.00	0.00	5.21	\$13.10
Primary Charge	0.967		5.74	0.00	0.00	5.04	\$10.78
Subtran Charge	0.954			0.00	0.00	4.97	\$4.97
Transmission Charge	0.940				0.00	4.90	\$4.90

Kentucky Power Company  
Annual Investment Carrying Charges  
Twelve Months Ended May 31, 2025

	Investment Life (Years)											
	2	3	4	5	10	15	20	25	30	33	40	50
Return (1)	7.57	7.57	7.57	7.57	7.57	7.57	7.57	7.57	7.57	7.57	7.57	7.57
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
	59.07	41.73	33.22	27.98	17.78	14.61	13.06	12.06	11.42	11.15	10.69	10.31

(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

Kentucky Power Company  
COGEN Rate Design  
Twelve Months Ended May 31, 2025

**I. Assumptions**

		<u>Variable</u>	<u>Value</u>
A)	Capital Cost per kW of Capacity	V	\$1,126 /kW
B)	Weighted Cost of Capital (Workpaper S-2)	R	7.57%
C)	Carrying Charge Rate	CCR	12.86%
D)	Operation & Maintenance Cost per Year (Fixed & Variable)	O	\$12.65 /kW
E)	Line Losses	L	8.80%
F)	Estimated Unit Life	N	30 years
G)	Present Value of Carrying Charge for \$1 Investment for N years	D	1.5089
H)	Fixed Operation and Maintenance Cost Escalation Rate	IO	2.00%
I)	Construction Cost Escalation Rate	IP	2.00%

**II. Calculation of Present Value of Carrying Charge**

$$D = CCR \times \frac{(1 + R)^N - 1}{R \times (1 + R)^N}$$

$$D = 12.86\% \times \frac{7.9276}{0.6758} = 1.5089$$

**III. Calculation of Unadjusted Monthly Avoided Cost of Capacity**

$$C = \left( \frac{1}{12} \right) \times \left[ \frac{\left( D \times V \times \frac{S1}{S2} \times S3 \right) + (S4 \times S5)}{S6} \right]$$

Where:

$$S1 = 1 - \frac{1 + IP}{1 + R}$$

$$S2 = 1 - \left( \frac{1 + IP}{1 + R} \right)^N$$

$$S3 = (1 + IP)^{(T-1)}$$

$$S4 = O \times \left( \frac{1 + IO}{1 + R} \right)$$

$$S5 = (1 + IO)^{(T-1)}$$

$$S6 = 1 - \frac{L}{2}$$

Kentucky Power Company  
COGEN Rate Design  
Twelve Months Ended May 31, 2025

**Calculation for First Year**

T =	1		
S1 =	0.0518	S4 =	11.9950
S2 =	0.7971	S5 =	1.0000
S3 =	1.0000	S6 =	0.9560

$$C = \left( \frac{1}{12} \right) \times \left[ \frac{\left( 1.4258 \times 828 \times \frac{0.0577}{0.8316} \times 1 \right) + (5.6729 \times 1)}{0.9605} \right]$$

C = \$10.66

**Calculation for Second Year**

T =	2		
S1 =	0.0518	S4 =	11.9950
S2 =	0.7971	S5 =	1.0200
S3 =	1.0200	S6 =	0.9560

C = \$10.88

**Calculation for Third Year**

T =	3		
S1 =	0.0518	S4 =	11.9950
S2 =	0.7971	S5 =	1.0404
S3 =	1.0404	S6 =	0.9560

C = \$11.10

Three Year Average Avoided Cost of Capacity = \$10.88 on peak  
TOD Measurement

Three Year Average Avoided Cost of Capacity = \$4.53 average  
Standard Measurement

**Cost Calculations (CT Parameters)**

**IV. Operations & Maintenance Cost per kW**

Fixed & Variable Operations & Maintenance Cost (2025 Dollars)		5.18 mills/kWh
Hours per Year	x	8,760 hours
Unit Size	x	480,000 kW
Capacity Factor	x	31%
Planned Outage Rate	x	10.00%
Total Variable O&M Cost		\$6,071,267 /year
Unit Size	/	480,000 kW
Per Unit Variable O&M Cost		\$12.65 /kW

Kentucky Power Company  
COGEN Rate Design  
Twelve Months Ended May 31, 2025

V. Energy Payment Calculation \*

On-Peak      Off-Peak      Non-TOD

A Potential Loss Savings

Primary Losses			1.35%
Divided by 2	/		2
Loss Adjustment (Potential Loss Savings)			0.68%

B Time-of-Day Energy Payments

Avoided Energy Costs (2025-2027 Average)	5.94	4.13	¢/kWh
Divided by (1 - Loss Savings)	0.9932	0.9932	
Time-of-Day Energy Payments	<b>5.98</b>	<b>4.16</b>	¢/kWh

C Non-Time-of-Day Energy Payment

Time-of-Day Energy Payments	5.98	4.160	¢/kWh
Hours per Year	x 3,650	5,110	hours
Weighted Average of Hourly TOD Payments	21,827	21,258	43,085
Hours Per Year			8,760
Non-Time-of-Day Energy Payment			<b>4.92</b> ¢/kWh

\* On-Peak Period is 7am - 9pm, Monday through Friday  
Off-Peak Period is all other hours

VI. Demand and Energy Loss Calculations \*\*

<u>System</u>	<u>Demand</u>	<u>Energy</u>
Transmission	6.0%	3.0%
Subtransmission	1.7%	2.2%
Primary	1.0%	1.35%
Compound Loss Factor	<b>8.8%</b>	<b>6.7%</b>

\*\* Assuming COGEN/SPP Service at Primary

Kentucky Power Company  
COGEN Rate Design  
Twelve Months Ended May 31, 2025

VII. Annual Carrying Charge Rates

	<u>Variable</u>	<u>Value</u>
Fixed Costs		10.9%
O&M		4.9%
Carrying Costs	CC	15.8%

II. Charges

Contingencies		5%
Stores Expense		26%
Total Charges on Material	MC	31%
Labor		56%
Transportation Expense		22%
Total Charges on Labor	LC	78%

VIII. Overheads

Company Construction Overheads	OC	23%
--------------------------------	----	-----

IX. Monthly Charge on Incremental Material

IM = Incremental Material Cost  
IL = Incremental Labor Cost (50% of Material) = 0.5 x IM

$$\text{Monthly Charge on IM} = (1 + OC) \times [(1 + MC) \times IM + (1 + LC) \times IL] \times \frac{CC}{12}$$

Monthly Charge on IM = 3.57% of Incremental Material Cost

Kentucky Power Company  
COGEN Rate Design  
Twelve Months Ended May 31, 2025

X. Monthly Meter Charges

	Incremental Material (IM)	Monthly Charge 3.57%	Average Charge
<u>Standard Measurement</u>			
<u>Single Phase</u>			
Option 2 - Primary - Transformer Rated	391	\$13.96	
Option 2 - Secondary - Self-Contained	38	1.36	
Option 3 - Primary - Transformer Rated	391	13.96	
Option 3 - Secondary - Transformer Rated	391	13.96	
Option 3 - Secondary - Self Contained	38	1.36	
Total		\$ 44.60 / 5 =	\$8.92
		Use:	\$9.25
		current	9.25
<u>Polyphase</u>			
Option 2 - Primary - Transformer Rated	391	\$13.96	
Option 2 - Secondary - Self-Contained	230	8.21	
Option 3 - Primary - Transformer Rated (or Sec. >200 Amps)	391	13.96	
Option 3 - Secondary - Transformer Rated (Below 200 Amps)	391	13.96	
Option 3 - Secondary - Self Contained (Below 200 Amps)	230	8.21	
Total		\$ 58.30 / 5 =	\$11.66
		Use:	\$12.10
		current	12.1
<u>Time-of-Day Measurement</u>			
<u>Single Phase</u>			
Option 2 - Primary - Transformer Rated	400	\$14.28	
Option 2 - Secondary - Self-Contained	96	3.43	
Option 3 - Primary - Transformer Rated	400	14.28	
Option 3 - Secondary - Transformer Rated	400	14.28	
Option 3 - Secondary - Self Contained	38	1.36	
Total		\$ 47.63 / 5 =	\$9.53
		Use:	\$9.85
		Current	9.85
<u>Polyphase</u>			
Option 2 - Primary - Transformer Rated	400	\$14.28	
Option 2 - Secondary - Self-Contained	239	8.53	
Option 3 - Primary - Transformer Rated	400	14.28	
Option 3 - Secondary - Transformer Rated	400	14.28	
Option 3 - Secondary - Self Contained	239	8.53	
Total		\$ 59.90 / 5 =	\$11.98
		Use:	\$12.40
		current	12.4

XI. Calculation of Meter O&M Expense as a % of Original Cost (Per Books Total Company Values)

Account 586 - Operation	1,216,051
Account 597 - Maintenance	41,553
Total O&M	1,257,604
Account 370 - Meter Plant	25,665,628
O&M Percentage	4.9%



Kentucky Power Company  
COGEN Rate Design  
Twelve Months Ended May 31, 2025

<b>Combustion Turbine Parameters - KPCo</b>	
July 2025	
Construction Cost 2025\$	1125.8 \$/kW (Nominal)
Asset Life:	30 year
Depreciation Rate:	3.33%
Annual Generation:	631,649 MWh
Variable O&M:	0.64 \$ Million
Variable O&M:	0.97 \$/MWh
Variable O&M:	28,650.40 \$ for Start Cost
Fixed O&M	2.66 \$ Million
Fixed O&M	11.43 \$/kW-yr
Fixed O&M	4.21 \$/MWh
Levelized Capacity Factor	31% %
Forced Outage Factor	3.0 %
Capability	233 MW (Nominal)
	245 MW (Winter)
	226 MW (Summer)

**Big Run Producers LLC**  
**Summary of EDR Incremental Costs and Revenues**

Ln No.		Marginal Costs - Energy	
(1)	Annual kWh		5,083,200
(2)	DA LMP \$/kWh		0.03174
(3)	Marginal Costs - Energy		\$161,345
=(1)*(2)			
		Marginal Costs - Distribution	
(4)	Distribution WO Total		\$267,807
(5)	Levelized Carrying Cost		10.78%
(6)			
=(4)*(5)		Annual Dist Incremental Cost	\$28,870
Summary of Incremental Costs and Revenues			
(7)	Energy		\$161,345
(8)	Distribution		\$28,870
(9)	PJM LSE Transmission		\$39,497
(10)	Generation Capacity		\$26,980
(11)			
=(7)+(8)+(9)+(10)		Total Incremental Costs	\$256,692
(12)	Incremental Revenue	\$	831,594
(13)			
=(12)-(11)		Net Revenue (Cost)	\$ 574,902

**Cyber Innovations Group LLC**  
**Summary of EDR Incremental Costs and Revenues**

Ln No.		Marginal Costs - Energy	
(1)	Annual kWh		121,402,000
(2)	DA LMP \$/kWh		0.03174
(3)	Marginal Costs - Energy		\$3,853,393
=(1)*(2)			
		Marginal Costs - Distribution	
(4)	Distribution WO Total		\$0
(5)	Levelized Carrying Cost		10.78%
(6)			
=(4)*(5)		Annual Dist Incremental Cost	\$0
Summary of Incremental Costs and Revenues			
(7)	Energy		\$3,853,393
(8)	Distribution		\$0
(9)	PJM LSE Transmission		\$631,344
(10)	Generation Capacity		\$30,025
(11)	Total Incremental Costs		\$4,514,762
=(7)+(8)+(9)+(10)			
(12)	Incremental Revenue	\$	6,530,561
(13)	Net Revenue (Cost)	\$	2,015,800
=(12)-(11)			

**Dajcor Aluminum**  
**Summary of EDR Incremental Costs and Revenues**

Ln No.		Marginal Costs - Energy	
(1)	Annual kWh		4,585,000
(2)	DA LMP \$/kWh		0.03174
(3)	Marginal Costs - Energy		\$145,531
=(1)*(2)			
		Marginal Costs - Distribution	
(4)	Distribution WO Total		\$0
(5)	Levelized Carrying Cost		10.78%
(6)	Annual Dist Incremental Cost		\$0
=(4)*(5)			
Summary of Incremental Costs and Revenues			
(7)	Energy		\$145,531
(8)	Distribution		\$0
(9)	PJM LSE Transmission		\$33,234
(10)	Generation Capacity		\$9,646
(11)	Total Incremental Costs		\$188,411
=(7)+(8)+(9)+(10)			
(12)	Incremental Revenue	\$	562,064
(13)	Net Revenue (Cost)	\$	373,652
=(12)-(11)			

**Discover AI LLC**  
**Summary of EDR Incremental Costs and Revenues**

Ln No.		Marginal Costs - Energy	
(1)	Annual kWh		108,885,000
(2)	DA LMP \$/kWh		0.03174
(3)	Marginal Costs - Energy		\$3,456,094
=(1)*(2)			
		Marginal Costs - Distribution	
(4)	Distribution WO Total		\$0
(5)	Levelized Carrying Cost		10.78%
(6)			
=(4)*(5)		Annual Dist Incremental Cost	\$0
		Summary of Incremental Costs and Revenues	
(7)	Energy		\$3,456,094
(8)	Distribution		\$0
(9)	PJM LSE Transmission		\$613,324
(10)	Generation Capacity		\$605
(11)	Total Incremental Costs		\$4,070,023
=(7)+(8)+(9)+(10)			
(12)	Incremental Revenue	\$	5,687,455
(13)	Net Revenue (Cost)	\$	1,617,432
=(12)-(11)			

Air Products  
Summary of Incremental Costs and Revenues  
2023-2025  
*DY 2024/25 June 2024- May 2025*

Ln No.	Marginal Costs - Energy	
(1)	Annual kWh	110,352,000
(2)	DA LMP \$/kWh	0.03815
(3)	Marginal Costs - Energy	\$4,209,623
=(1)*(2)		

Marginal Costs - Distribution		
(4)	Distribution WO Total	\$0
(5)	Levelized Carrying Cost	10.78%
(6)		
=(4)*(5)	Annual Dist Incremental Cost	\$0

Summary of Incremental Costs and Revenues		
(7)	Energy	\$4,209,623
(8)	Distribution	\$0
(9)	PJM LSE Transmission	\$804,217
(10)	Generation Capacity	\$120,133
(11)		
=(7)+(8)+(9)+(10)	Total Incremental Costs	\$5,133,974
(12)	Incremental Revenue	\$ 5,796,122
(13)		
=(12)-(11)	Net Revenue (Cost)	\$ 662,148

Air Products  
Summary of Incremental Costs and Revenues  
2023-2025  
***DY 2023/24 June 2023- May 2024***

Ln No.	Marginal Costs - Energy	
(1)	Annual kWh	109,752,000
(2)	DA LMP \$/kWh	0.03119
(3)	Marginal Costs - Energy	\$3,423,374
=(1)*(2)		

	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	\$3,423,374
(8)	Distribution	\$0
(9)	PJM LSE Transmission	\$643,629
(10)	Generation Capacity	\$177,365
(11)		
=(7)+(8)+(9)+(10)	Total Incremental Costs	\$4,244,368
(12)	Incremental Revenue	\$ 6,143,898
(13)		
=(12)-(11)	Net Revenue (Cost)	\$ 1,899,530

**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 Certain Regulatory And Accounting     )  
Treatments; and (4) All Other Required Approvals     )  
And Relief                                                         )

Case No. 2025-00257

**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. 2025-00257**

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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. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is Franz D. Messner. I am employed by American Electric Power Service  
3       Corporation (“AEPSC”) as Managing Director of Corporate Finance. AEPSC supplies  
4       engineering, financing, accounting, planning, advisory, and other services to the  
5       subsidiaries of the American Electric Power (“AEP”) system, one of which is Kentucky  
6       Power Company (“Kentucky Power” or the “Company”). My business address is 1  
7       Riverside Plaza, Columbus, Ohio, 43215.

**II. BACKGROUND**

8   **Q.   PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL**  
9       **BACKGROUND.**

10  A.   I earned a Bachelor of Science in Systems Engineering from the United States Naval  
11       Academy in 1990. I earned a Master of Business Administration from the Fisher College  
12       of Business at the Ohio State University in 1999. Prior to joining AEP, I served for  
13       approximately seven years as a U.S. Naval officer and completed both chief engineer and  
14       submarine officer qualifications.

15               In June 1999, I was hired by AEPSC as an associate in a finance associate  
16       development program. My primary roles have been in the areas of financial analysis,

1 budgeting, and forecasting. In July 2007, I was named Manager in Corporate Planning and  
2 Budgeting and subsequently promoted to Director in November 2009. In May 2016, I  
3 assumed my current position as Managing Director of Corporate Finance.

4 **Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF**  
5 **CORPORATE FINANCE?**

6 A. I am responsible for planning and executing the corporate finance programs of the  
7 regulated AEP System operating companies, including Kentucky Power. My  
8 responsibilities also include preparing recommendations for the payment of dividends by  
9 those companies, maintaining capitalization targets, and managing the relationships of  
10 AEP and its subsidiaries with the credit rating agencies.

11 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY**  
12 **PROCEEDINGS?**

13 A. Yes. I have submitted testimony on behalf of Kentucky Power before the Public Service  
14 Commission of Kentucky (the "Commission") including Kentucky Power's last two base  
15 rate cases. I have also submitted testimony on behalf of Indiana Michigan Power before  
16 the Indiana Utility Regulatory Commission and the Michigan Public Service Commission,  
17 Ohio Power before the Public Utilities Commission of Ohio, Appalachian Power before  
18 the Virginia State Corporation Commission and Kingsport Power before the Tennessee  
19 Public Utility Commission. Additionally, I have prepared or had prepared under my direct  
20 supervision financing applications submitted on behalf of Kentucky Power to the  
21 Commission.

### **III. PURPOSE OF TESTIMONY**

1 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
2 **PROCEEDING?**

3 A. The purpose of my Direct Testimony in this proceeding is to present and support Kentucky  
4 Power's proposed capital structure and weighted average cost of capital ("WACC"),  
5 inclusive of pro forma adjustments made to incorporate the impact of the issuance of the  
6 securitization bonds on June 12, 2025, and other standard adjustments. In addition, I  
7 address the Commission's expectation that the Company provide sufficient evidence in this  
8 base rate case as to whether the remarketing of the \$65 million West Virginia Economic  
9 Development Authority ("WVEDA") bonds was necessary for the period chosen and was  
10 incurred in an appropriate and prudent manner. I also describe Kentucky Power's credit  
11 ratings and why regulatory outcomes are important in the rating process.

12 **Q. ARE YOU SPONSORING ANY SCHEDULES?**

13 A. Yes. I am sponsoring the following Section V Workpapers, which are filed in the  
14 Company's application:

- 15 • Section V, Workpaper S-2 Page 1 – Cost of Capital
- 16 • Section V, Schedule 3 – Capitalization
- 17 • Section V, Workpaper S-3 Page 1 – Long-Term Debt
- 18 • Section V, Workpaper S-3 Page 2 – Schedule of Short-Term Debt

**IV. PROPOSED COST OF CAPITAL AND CAPITAL STRUCTURE**

1 **Q. PLEASE DESCRIBE KENTUCKY POWER’S CAPITAL STRUCTURE AT THE**  
 2 **END OF THE TEST YEAR.**

3 A. Based on the test year ended May 31, 2025, Kentucky Power’s per books capital structure  
 4 is set forth in Figure FDM-1 below:

**Figure FDM-1**

Line No. (1)	<u>Description</u> (2)	PER BOOK <u>BALANCE</u> (3)	% of <u>Total</u> (4)
1	Long Term Debt	\$ 1,365,000,000	55.82%
2	Short Term Debt	\$ 85,199,814	3.48%
3	Common Equity	\$ 995,158,147	40.70%
4	Total	\$ 2,445,357,961	100.00%

5 **Q. HOW DO THE MAY 31, 2025 PER BOOKS DEBT AND EQUITY COMPONENTS**  
 6 **COMPARE TO THE CAPITAL STRUCTURE PROPOSED IN THE**  
 7 **COMPANY’S LAST TWO BASE RATE CASES (CASE NO. 2020-00174 AND**  
 8 **CASE NO. 2023-00159)?**

9 A. The Company’s March 31, 2020, per books capital structure in Case No. 2020-00174  
 10 consisted of 56.7% debt and 43.3% equity. The Company’s March 31, 2023, per books  
 11 capital structure in Case No. 2023-00159 consisted of 58.3% debt and 41.7% equity. Thus,  
 12 the Company’s equity ratio has continued to shrink over time.

1   **Q.    IS ANY OF THE DECREASE IN EQUITY RELATIVE TO DEBT IN THE**  
2       **COMPANY’S CAPITAL STRUCTURE ATTRIBUTABLE TO PAYMENT OF**  
3       **DIVIDENDS FROM KENTUCKY POWER TO ITS PARENT COMPANY?**

4   A.   No. Kentucky Power has made no dividend payments since 2019.

5   **Q.    HAS THE COMMISSION DIRECTED KENTUCKY POWER TO MAKE**  
6       **CHANGES TO ITS CAPITAL STRUCTURE?**

7   A.   Yes. I understand that on multiple occasions the Commission has indicated a desire to see  
8       Kentucky Power and other utilities in the Commonwealth maintain a “reasonably  
9       balanced” capital structure as discussed in the Direct Testimony of Company Witness  
10      Newcomb.

11   **Q.    WAS THERE A MATERIAL CHANGE TO THE COMPANY’S CAPITAL**  
12      **STRUCTURE AFTER THE TEST YEAR?**

13   A.   Yes. As discussed in the Direct Testimony of Company Witness Newcomb, shortly after  
14      the close of the test year, on June 12, 2025, the previously approved securitization bonds  
15      were issued, which resulted in a change to the Company’s capital structure. Two \$150  
16      million term loans and the outstanding balance of short-term debt was repaid with cash  
17      proceeds from securitization on June 12, 2025. Kentucky Power’s short-term debt position  
18      moved from a borrowing position to an invested position as the balance was reduced to  
19      zero.

1 **Q. PLEASE DESCRIBE THE IMPACT THAT THE SECURITIZATION PROCEEDS**  
 2 **HAD ON KENTUCKY POWER'S CAPITAL STRUCTURE.**

3 A. After adjusting the May 31, 2025 per books balances for the repayment of approximately  
 4 \$385 million of debt, the adjusted per books capital structure consists of 51.70% debt and  
 5 48.30% equity as shown in Figure FDM-2 below.

**Figure FDM-2**

Line No.	Description	PER BOOK BALANCE	% of Total	ADJUSTMENTS FOR DEBT REPAYMENT	ADJUSTED BALANCE	% of Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Long Term Debt	\$ 1,365,000,000	55.82%	\$ (300,000,000)	\$ 1,065,000,000	51.70%
2	Short Term Debt	\$ 85,199,814	3.48%	\$ (85,199,814)	\$ -	0.00%
3	Common Equity	\$ 995,158,147	40.70%		\$ 995,158,147	48.30%
4	Total	\$ 2,445,357,961	100.00%		\$ 2,060,158,147	100.00%

6 **Q. IS THE COMPANY PROPOSING ANY FURTHER ADJUSTMENTS TO THE**  
 7 **COMPANY'S CAPITAL STRUCTURE?**

8 A. Yes. As set forth in Figure FDM-3, the securitization bonds yielded a principal amount of  
 9 \$477,749,000, which were then used to pay \$9,451,609 in upfront costs of issuance, then  
 10 pay off \$300,000,000 of term loans and \$85,199,814 of short-term debt as I previously  
 11 discussed. As discussed in the Direct Testimony of Company Witness Newcomb, the  
 12 Company is also proposing an additional adjustment to reduce the adjusted  
 13 (post-securitization) equity balance by the amount of remaining available securitization  
 14 proceeds: \$83,079,578.

**Figure FDM-3**

<b>From the Securitization Bond Issuance Advice Letter</b>		
Principal Amount of Issuance		\$ 477,749,000
Less: Upfront Financing Costs		\$ (9,451,609)
<b>Net Proceeds Available</b>		<b>\$ 468,297,391</b>
Less \$300,000,000 term loan repayment		\$ (300,000,000)
Less \$85,199,814 5/31/25 short term debt balance		\$ (85,199,814)
<b>Securitization Proceeds Remaining</b>		<b>\$ 83,097,578</b>

1 **Q. PLEASE DESCRIBE KENTUCKY POWER'S PROPOSED CAPITAL**  
2 **STRUCTURE THAT INCORPORATES THESE CAPITAL STRUCTURE**  
3 **ADJUSTMENTS.**

4 A. As set forth in Figure FDM-4 below, the Company's adjusted capital structure goes from  
5 one containing a May 31, 2025, per books equity ratio of 40.70% to an adjusted pro forma  
6 equity ratio 46.13%.

**Figure FDM-4**

Line No. (1)	Description (2)	PER BOOK BALANCE (3)	% of Total (4)	ADJUSTED BALANCE (5)	% of Total (6)
1	Long Term Debt	\$ 1,365,000,000	55.82%	\$ 1,065,000,000	53.87%
2	Short Term Debt	\$ 85,199,814	3.48%	\$ -	0.00%
3	Common Equity	\$ 995,158,147	40.70%	\$ 912,060,569	46.13%
4	Total	\$ 2,445,357,961	100.00%	\$ 1,977,060,569	100.00%



**Q. PLEASE EXPLAIN HOW THE PROPOSED WEIGHTED AVERAGE COST OF CAPITAL OF 7.5740% 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 adjusted capital structure, including long-term debt, short-term debt, and common stock. The calculation is shown on Section V, Schedule 2, page 1 and in Figure FDM-5 below. The Company used the proposed Reapportioned Kentucky jurisdictional capitalization as calculated on Section V, Schedule 3, column 13 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 rate for each source of capital.

**Figure FDM-5**

KENTUCKY POWER COMPANY  
PROPOSED COST OF CAPITAL  
TEST YEAR ENDED MAY 31, 2025

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	\$ 990,515,425	53.87%	5.490%	2/ 2.96%
2	Short Term Debt	\$ 0	0.00%	5.500%	3/ 0.00%
3	Common Equity	\$ 848,272,359	46.13%	<b>10.00%</b>	4/ 4.61%
4	Total	\$ 1,838,787,784	100.00%		<b>7.5740%</b>

Schedule 3, Column 13, Lines 1, 2, 3 & 4  
Per workpaper S-3, Page 1, Column 14, Line 14  
Per workpaper S-3, Page 2, Column 4, Line 16  
Per Recommendation of Company Witnesses McKenzie/Wiseman

1   **Q.     PLEASE EXPLAIN WHAT RATES WERE USED IN CALCULATING THE**  
2   **COMPANY’S PROPOSED WEIGHTED AVERAGE COST OF CAPITAL.**

3   A.     The weighted cost of long-term debt was determined by taking the sum of each debt  
4     instrument’s actual annualized cost and dividing that amount by the total debt outstanding  
5     as of May 31, 2025. The annualized cost for each debt instrument was calculated by  
6     multiplying the effective cost rate (yield to maturity) by the net proceeds outstanding, as  
7     set forth in Section V, Workpaper S-3, page 1.

8             The cost of short-term debt used in the calculation is the Company’s actual  
9     short-term interest expense for the 12 months ended May 31, 2025, divided by the actual  
10    average borrowings outstanding during the same time period. Please refer to Section V,  
11    Workpaper S-3, page 2. As mentioned earlier, the per books balances are adjusted to  
12    account for known and measurable changes to the Company’s capitalization as shown in  
13    Section V, Schedule 3 and detailed in the testimonies of Company Witnesses Cullop, Ross,  
14    and Ciborek. Though the per books short-term debt balance on May 31, 2025, was  
15    approximately \$85 million, the adjusted balance included in the proposed weighted average  
16    cost of capital calculation was \$0 due to the use of securitization proceeds to eliminate that  
17    debt as shown in Section V, Schedule 3, column 4.

18            The 10.0% cost of common equity used in the calculation is based on the range of  
19    10.0%–11.0% described in the Direct Testimony of Company Witness McKenzie and  
20    subsequent refinement as described in the Direct Testimony of Company Witness  
21    Wiseman.

1   **Q.     GIVEN THAT THE PROPOSED CAPITALIZATION EXCLUDES THE TWO**  
2       **\$150 MILLION TERM LOANS, WAS THE COST OF THOSE TERM LOANS**  
3       **ALSO EXCLUDED FROM THE CALCULATION OF THE COST OF**  
4       **LONG-TERM DEBT?**

5   A.   No. Though the balances of the two \$150 million term loans were excluded from the capital  
6       structure, the impact on the cost of long-term debt was not adjusted because doing so would  
7       have increased the cost of long-term debt used in the cost of capital calculation. In an effort  
8       to reduce the WACC and the corresponding impact on customers, the Company chose to  
9       use the lower cost of debt that included the cost impact of the two \$150 million term loans  
10      that were paid with the securitization proceeds.

11   **Q.     DOES THE PROPOSED CAPITAL STRUCTURE INCLUDE ANY AMOUNTS**  
12      **FOR SALE OF ACCOUNTS RECEIVABLE?**

13   A.   No. Consistent with the Company's prior base rate case, Case No. 2023-00159, sale of  
14      accounts receivable is not included in the capital structure.

15   **Q.     IS THE PROPOSED CAPITAL STRUCTURE APPROPRIATE, REASONABLE,**  
16      **AND PRUDENT?**

17   A.   Yes. The 53.87% debt and 46.13% equity ratio strikes a reasonable balance and is  
18      consistent with the Moody's Investor Service ("Moody's") target range for a Baa3 rated  
19      company. It is within the Moody's target debt to capitalization range for a vertically  
20      integrated utility of 45%–55%. It is also lower than the currently authorized equity ratios  
21      for investor-owned utilities in the Commonwealth whose authorized equity ratios range  
22      from 52.145% to 53.23%. At the same time, it is responsive to the Commission's directive

1 to increase Kentucky Power's level of equity in its capital structure as discussed by  
2 Company Witness Newcomb.

**V. ISSUANCE EXPENSE ASSOCIATED WITH POLLUTION CONTROL REVENUE  
BOND REMARKETING**

3 **Q. PLEASE DESCRIBE THE WEST VIRGINIA ECONOMIC DEVELOPMENT**  
4 **AUTHORITY ("WVEDA") SOLID WASTE DISPOSAL FACILITIES REVENUE**  
5 **REFUNDING BONDS (KENTUCKY POWER COMPANY – MITCHELL**  
6 **PROJECT) SERIES 2014A POLLUTION CONTROL REVENUE BOND ("PCRB")**  
7 **REMARKETING.**

8 A. The \$65 million PCRBS were originally issued in 2014 and contain a provision that allows  
9 for a variety of interest rate determination methods from weekly resetting of the interest  
10 rate to extending the bonds to their final April 1, 2036, maturity. Since 2014, they have  
11 generally been remarketed with an interest rate determination mode based on a three-year  
12 period, after which they are remarketed for another three-year period. Most recently the  
13 PCRBS were remarketed in 2017, 2020, and 2023 with three-year periods between the time  
14 they are subject to mandatory tender by the Company, which was last required in 2023  
15 when the PCRBS were last remarketed.

16 **Q. HAVE YOU EXCLUDED THE ISSUANCE EXPENSE ASSOCIATED WITH THE**  
17 **\$65 MILLION WVEDA BONDS FROM THE COST OF LONG-TERM DEBT?**

18 A. No. The issuance expense is included in the cost of long-term debt that was used to  
19 calculate the weighted average cost of capital proposed in this case. I understand that the  
20 Commission issued an Order in Case No. 2023-00159 finding that the issuance expense of  
21 the \$65 million WVEDA bonds should be removed from the cost of long-term debt.

1   **Q.     WHY HAVE YOU INCLUDED THE ISSUANCE EXPENSE ASSOCIATED WITH**  
2           **THE 2023 REMARKETING OF THE \$65 MILLION AS PART OF THE COST OF**  
3           **LONG-TERM DEBT?**

4   A.    The WVEDA bonds were originally issued under authority granted by the Commission in  
5           Case No. 2013-00410, with an interest rate determination mode feature allowing the bonds  
6           to be issued and subsequently remarketed from time-to-time at the issuers' discretion,  
7           allowing the issuer to determine, based on market conditions and investor appetite, the  
8           beneficial tenor and rate mode with which to remarket the bonds. Prior to the last  
9           remarketing in June 2023, the bonds were remarketed in June 2020 with a three-year tenor,  
10          which required them to be remarketed in June 2023. Thus, the June 2023 remarketing was  
11          mandatory per the terms of the June 2020 Bond Purchase Agreement. The rate environment  
12          in June 2020, shortly after the onset of the COVID-19 pandemic, was lower than it was in  
13          June 2023 when the mandatory remarketing was required, which resulted in an increased  
14          rate when the bonds were remarketed in June 2023. The 2023 remarketing had been in  
15          Kentucky Power's forecast for the prior three years and had been reviewed with the  
16          Company multiple times given its forecasting process that typically results in at least two  
17          forecast updates annually. Because the remarketing was mandatory, and not simply  
18          discretionary, the issuance costs associated with that remarketing were unavoidable and  
19          therefore prudently and reasonably incurred. Thus, the issuance expense should be included  
20          in the cost of long-term debt.

## **VI. CREDIT RATINGS**

1 **Q. WHAT ARE CREDIT RATINGS AND WHAT IS AN INVESTMENT GRADE**  
2 **RATING?**

3 A. Credit ratings are opinions on a company's ability to repay its debt and other obligations  
4 in full and on time. Credit ratings facilitate the process of issuing bonds by providing a  
5 widely recognized measure of relative credit risk. Investors may also use ratings as a  
6 screening device for investments. For example, an investor may choose only to invest in  
7 investment grade corporations or utilities.

8 **Q. DESCRIBE THE METHODOLOGY OF EACH RATING AGENCY.**

9 A. Standard and Poor's ("S&P") evaluates the credit of each operating company utilizing a  
10 family approach, factoring in the ratings of all AEP system subsidiaries. S&P's family  
11 approach to bond ratings for individual operating companies stresses the inherent benefits  
12 and risks associated with having a diversified family of operating companies across AEP's  
13 11-state service territory.

14 Moody's and Fitch Ratings ("Fitch") rate each operating company individually  
15 based on the merits of the company's operations and credit profile but does recognize that  
16 each is part of a larger holding company.

17 **Q. PLEASE PROVIDE A SUMMARY OF THE CURRENT SENIOR UNSECURED**  
18 **CREDIT RATINGS FOR KENTUCKY POWER.**

19 A. Kentucky Power is currently rated BBB (stable outlook) by S&P, Baa3 (stable outlook) by  
20 Moody's, and BBB+ (stable outlook) by Fitch. On March 11, 2025, Moody's published a  
21 credit opinion on Kentucky Power reaffirming its rating of Baa3 (stable). Moody's noted  
22 that the Company has a history of average regulatory support and has generated weak cash

1 flow and cash flow-based credit metrics due to factors including unfavorable economic  
2 conditions and deferred storm and purchased power cost recovery. Moody's further noted  
3 that one of the factors that could lead to a downgrade is if the Company's relationship with  
4 its regulator deteriorates, or if there is an increase in regulatory lag, such that the Company  
5 is unable to recover costs on a timely basis. On December 10, 2024, Fitch published a credit  
6 opinion on Kentucky Power reaffirming its rating of BBB+ (stable). Fitch indicated the  
7 ratings reflect the Company's integrated utility asset base and the somewhat restrictive  
8 regulatory environment in Kentucky. Fitch also noted that one of the key rating drivers was  
9 uncertain regulation. On September 19, 2024, S&P published a credit opinion on Kentucky  
10 Power reaffirming its rating of BBB (negative). S&P noted that Kentucky Power's recent  
11 rate order (Case No. 2023-00159) is less than credit supportive and that the Company's  
12 stand-alone financial measures remain weak for its rating. On July 10, 2025, S&P returned  
13 AEP Inc. and all its subsidiary companies, including Kentucky Power, outlooks to "stable"  
14 from "negative."

15 **Q. IS REGULATORY TREATMENT IMPORTANT TO THE RATING AGENCIES?**

16 A. Yes. A significant portion of the Company's credit rating is based on qualitative factors  
17 related to the regulatory environment. Rating agencies closely follow regulatory outcomes  
18 for a utility. Consistent and appropriate regulatory treatment is credit positive and supports  
19 the Company's credit ratings, which in turn affords the Company better access to capital  
20 markets to source capital at lower cost. This is important in times of increased debt capital  
21 market uncertainty.

**VII. CONCLUSION**

1   **Q.     DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2   **A.     Yes, it does.**



## VERIFICATION

The undersigned, Franz D. Messner, being duly sworn, deposes and says he is the Managing Director of Corporate Finance 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.



Franz D. Messner

Franklin

Chambers Ohio

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Franz D. Messner, on August 11, 2025.



Notary Public

My Commission Expires Never

Notary ID Number —



**COMMONWEALTH OF KENTUCKY  
BEFORE THE PUBLIC SERVICE COMMISSION**

In the Matter of:

Electronic Application Of Kentucky Power For (1) A	)	
General Adjustment Of Its Rates For Electric	)	
Service; (2) Approval Of Tariffs And Riders; (3)	)	
Approval Of Certain Regulatory And Accounting	)	Case No. 2025-00257
Treatments; and (4) 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. 2025-00257**

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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. 2025-00257**

**LIST OF EXHIBITS**

<b><u>Exhibit</u></b>	<b><u>Description</u></b>
AMM-1	Qualifications of Adrien M. McKenzie
AMM-2	ROE Analysis—Summary of Results
AMM-3	Regulatory Mechanisms
AMM-4	Capital Structure
AMM-5	DCF Model—Utility Group
AMM-6	br + sv Growth Rate
AMM-7	CAPM
AMM-8	ECAPM
AMM-9	Utility Risk Premium
AMM-10	Expected Earnings Approach
AMM-11	Flotation Cost Study
AMM-12	DCF Model—Non-Utility Group

## **GLOSSARY OF TERMS**

<b>Term</b>	<b>Meaning</b>
AEP	American Electric Power Company, Inc.
CAPM	Capital Asset Pricing Model
Commission	Public Service Commission of Kentucky
CPI	Consumer Price Index
DCF	Discounted Cash Flow
DPS	dividends per share
DSM	Demand Side Management
ECAPM	Empirical Capital Asset Pricing Model
EPS	earnings per share
FERC	Federal Energy Regulatory Commission
FINCAP, Inc.	Financial Concepts and Applications, Inc.
Fitch	Fitch Ratings, Inc.
Kentucky Power or the Company	Kentucky Power Company
Moody's	Moody's Investors Service
MW	megawatt
PCE	Personal Consumption Expenditures
PJM	PJM Interconnection, LLC
ROE	return on equity
RRA	S&P Global Market Intelligence, RRA Regulatory Focus
S&P	S&P Global Ratings
Value Line	The Value Line Investment Survey
Zacks	Zacks Investment Research, Inc.

**DIRECT TESTIMONY OF  
ADRIEN M. MCKENZIE, CFA ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

**Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A1. My name is Adrien M. McKenzie, and my business address is 3907 Red River, Austin, Texas, 78751.

**Q2. IN WHAT CAPACITY ARE YOU EMPLOYED?**

A2. I am President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

**Q3. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.**

A3. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit AMM-1.

**Q4. FOR WHOM ARE YOU TESTIFYING IN THIS CASE?**

A4. I am testifying on behalf of Kentucky Power, which is an operating subsidiary of AEP.

**A. Overview**

**Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE?**

A5. As discussed in the Direct Testimony of Company Witness Wiseman, Kentucky Power Company (“Kentucky Power” or the “Company”) is requesting that the Public Service Commission of Kentucky (“Commission”) authorize a return on equity (“ROE”) of 10.0% for the Company. The purpose of my testimony is to evaluate the reasonableness of the 10.0% 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.

1 **Q6. ARE YOU SPONSORING ANY EXHIBITS?**

2 A6. Yes. I am sponsoring the following exhibits:

- 3 • Exhibit AMM-1 Qualifications of Adrien M. McKenzie
- 4 • Exhibit AMM-2 ROE Analyses—Summary of Results
- 5 • Exhibit AMM-3 Regulatory Mechanisms
- 6 • Exhibit AMM-4 Capital Structure
- 7 • Exhibit AMM-5 DCF Model—Utility Group
- 8 • Exhibit AMM-6 br + sv Growth Rate
- 9 • Exhibit AMM-7 CAPM
- 10 • Exhibit AMM-8 ECAPM
- 11 • Exhibit AMM-9 Utility Risk Premium
- 12 • Exhibit AMM-10 Expected Earnings Approach
- 13 • Exhibit AMM-11 Flotation Cost Study
- 14 • Exhibit AMM-12 DCF Model—Non-Utility Group

15 **Q7. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELY ON**  
16 **TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR**  
17 **TESTIMONY.**

18 A7. To prepare my testimony, I use information from a variety of sources that would normally  
19 be relied upon by a person in my capacity. I am familiar with the Company's organization,  
20 finances, and operations from my participation in prior proceedings before the  
21 Commission. In connection with the present filing, I consider and rely upon discussions  
22 with corporate management, publicly available financial reports, and prior regulatory  
23 filings relating to Kentucky Power. I also review information relating generally to current  
24 capital market conditions and specifically to investor perceptions, requirements, and  
25 expectations for Kentucky Power's electric utility operations. These sources, coupled with  
26 my experience in the fields of finance and utility regulation, have given me a working

1 knowledge of the issues relevant to investors' required return for Kentucky Power, and they  
2 form the basis of my analyses and conclusions.

3 **Q8. HOW IS YOUR TESTIMONY ORGANIZED?**

4 A8. First, I summarize the results of my analyses and present my evaluation of the  
5 reasonableness of the 10.0% ROE requested by Kentucky Power, giving special attention  
6 to the importance of financial strength and the implications of regulatory mechanisms and  
7 other risk factors. I also comment on the reasonableness of the Company's proposed capital  
8 structure.

9 Next, I briefly review Kentucky Power's operations and finances. I then discuss  
10 current conditions in the capital markets and their implications in evaluating a just and  
11 reasonable return for the Company. I then explain the development of the proxy group of  
12 electric utilities used as the basis for my quantitative analyses. With this as a background,  
13 I discuss well-accepted quantitative analyses to estimate the current cost of equity for the  
14 proxy group of electric utilities. These include the DCF model, the CAPM, the ECAPM,  
15 an equity risk premium approach based on allowed equity returns, and reference to  
16 expected earned rates of return for electric utilities, which are all methods that are  
17 commonly relied on in regulatory proceedings.

18 Based on the results of my analyses, I evaluate the reasonableness of the 10.0%  
19 ROE requested by Kentucky Power. My evaluation considers the specific risks for the  
20 Company's electric operations and Kentucky Power's requirements for financial strength.  
21 Further, consistent with the fact that utilities must compete for capital with firms outside  
22 their own industry, I corroborate my utility quantitative analyses by applying the DCF  
23 model to a group of low-risk non-utility firms.



1 **B. Summary and Conclusions**

2 **Q9. WHAT IS YOUR CONCLUSION REGARDING THE 10.0% ROE REQUESTED**  
3 **BY KENTUCKY POWER?**

4 A9. I apply the DCF, CAPM, ECAPM, risk premium, and expected earnings analyses to a proxy  
5 group of electric utilities, with the results being summarized on Exhibit AMM-2. As shown  
6 there, based on the results of my analysis, I determined that the current cost of equity for  
7 Kentucky Power falls in the range of 10.0% to 11.0%, with a midpoint of 10.5%.  
8 Accordingly, I conclude that Kentucky Power's requested ROE of 10.0% significantly  
9 understates investors' required return for the Company. Kentucky Power's requested ROE  
10 represents a reasonable compromise between balancing the impact on customers and the  
11 need to provide the Company with a return that is adequate to compensate investors.

12 Because Kentucky Power's requested ROE of 10.0% already understates investors'  
13 required return for the Company, it should not be further reduced for purposes of single-  
14 issue cost recovery mechanisms, such as the Environmental Surcharge or  
15 Decommissioning Rider, as the Commission did in its January 13, 2021 Order in Case No.  
16 2020-00174. Such a reduction is not justified from a capital attraction point of view  
17 because it does not reflect investors' required return for the Company; but in any case, even  
18 if the Commission were inclined to make such a reduction, the requested 10.0% ROE is  
19 already 50 basis points below the ROE of 10.5% that my testimony supports.

20 I also examine the reasonableness of Kentucky Power's capital structure,  
21 considering both the specific risks faced by the Company and other industry guidelines.  
22 Based on this examination, I conclude that the Company's investor-supplied capital  
23 structure of 46.13% equity and 53.87% debt is reasonable considering industry benchmarks  
24 and the importance of maintaining Kentucky Power's financial strength to meet the capital  
25 requirements of its customers.

## **II. RETURN ON EQUITY FOR KENTUCKY POWER**

### **Q10. WHAT IS THE PURPOSE OF THIS SECTION?**

A10. This section presents my conclusions regarding the fair ROE applicable to Kentucky Power's 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**

### **Q11. WHAT IS THE ROLE OF THE ROE IN SETTING A UTILITY'S RATES?**

A11. 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 to sound regulatory economics and the standards set forth 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 reasonably 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.<sup>1</sup>

The *Hope* case expanded on the guidelines for a reasonable ROE, reemphasizing its 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:

---

<sup>1</sup> *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 692–93 (1923) (“*Bluefield*”).

1 From the investor or company point of view it is important that there be  
2 enough revenue not only for operating expenses but also for the capital costs  
3 of the business. These include service on the debt and dividends on the  
4 stock. . . . By that standard, the return to the equity owner should be  
5 commensurate with returns on investments in other enterprises having  
6 corresponding risks. That return, moreover, should be sufficient to assure  
7 confidence in the financial integrity of the enterprise, so as to maintain  
8 credit and attract capital.<sup>2</sup>

9 In summary, the Supreme Court's findings in *Hope* and *Bluefield* established that a  
10 just and reasonable ROE must be sufficient to 1) fairly compensate the utility's investors,  
11 2) enable the utility to offer a return adequate to attract new capital on reasonable terms,  
12 and 3) maintain the utility's financial integrity. These standards should allow the utility to  
13 fulfill its obligation to provide reliable service while meeting the needs of customers  
14 through necessary system replacement and expansion, but the Supreme Court's  
15 requirements can only be met if the utility has a reasonable opportunity to actually earn its  
16 allowed ROE.

17 Although the *Hope* and *Bluefield* decisions did not establish a particular method to  
18 be followed in fixing rates (or in determining the allowed ROE),<sup>3</sup> these and subsequent  
19 cases enshrined the importance of an end-result that meets the opportunity cost standard of  
20 finance. Under this doctrine, the required return is established by investors in the capital  
21 markets based on expected returns available from comparable risk investments. Coupled  
22 with modern financial theory, which has led to the development of formal risk-return  
23 models (e.g., DCF and CAPM), practical application of the *Bluefield* and *Hope* standards  
24 involves the independent, case-by-case consideration of capital market data in order to  
25 evaluate an ROE that will produce a balanced and fair end result for investors and  
26 customers.

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<sup>2</sup> *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) ("*Hope*") (internal citations omitted).

<sup>3</sup> *Id.* at 602 (noting that "the Commission was not bound to the use of any single formula or combination of formulae in determining rates" and, "it is not theory but the impact of the rate order which counts" (citing *Fed. Power Comm'n v. Nat. Pipeline Co.*, 315 U.S. 575, 586 (1942))).

1 **Q12. THROUGHOUT YOUR TESTIMONY YOU REFER REPEATEDLY TO THE**  
2 **CONCEPTS OF “FINANCIAL STRENGTH,” “FINANCIAL INTEGRITY,” AND**  
3 **“FINANCIAL FLEXIBILITY.” WOULD YOU BRIEFLY DESCRIBE WHAT YOU**  
4 **MEAN BY THESE TERMS?**

5 A12. These terms are generally synonymous and refer to the utility’s ability to attract and retain  
6 the capital that is necessary to provide service at reasonable cost, consistent with the  
7 Supreme Court standards. Kentucky Power’s plans call for a continuation of capital  
8 investments to preserve and enhance service reliability for its customers. The Company  
9 must generate adequate cash flow from operations, together with access to capital from  
10 external sources, to fund these requirements and for repayment of maturing debt.

11 Rating agencies and potential debt investors tend to place significant emphasis on  
12 maintaining strong financial metrics and credit ratings that support access to debt capital  
13 markets under reasonable terms. This emphasis on financial metrics and credit ratings is  
14 shared by equity investors who also focus on cash flows, capital structure and liquidity,  
15 much like debt investors.

16 **Q13. WHAT PART DOES REGULATION PLAY IN ENSURING THAT KENTUCKY**  
17 **POWER HAS ACCESS TO CAPITAL UNDER REASONABLE TERMS AND ON A**  
18 **SUSTAINABLE BASIS?**

19 A13. Regulatory signals are a major driver of investors’ risk assessment for utilities. Investors  
20 recognize that constructive regulation is a key ingredient in supporting utility credit ratings  
21 and financial integrity. Security analysts study commission orders and regulatory policy  
22 statements to advise investors about where to put their money. As Moody’s noted, “The  
23 regulatory framework is important because it provides the basis for decisions that affect  
24 utilities, including rate-setting as well as consistency and predictability of regulatory  
25 decision-making.”<sup>4</sup> Similarly, S&P has observed that, “Regulatory advantage is the most

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<sup>4</sup> Moody’s Investors Service, *Rating Methodology, Regulated Electric and Gas Utilities* (Aug. 6, 2024).

1 heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business  
2 risk profile.”<sup>5</sup> Value Line summarizes these sentiments:

3 As we often point out, the most important factor in any utility's success,  
4 whether it provides electricity, gas, or water, is the regulatory climate in  
5 which it operates. Harsh regulatory conditions can make it nearly  
6 impossible for the best run utilities to earn a reasonable return on their  
7 investment.<sup>6</sup>

8 In addition, the ROE set by regulators impacts investor confidence in not only the  
9 jurisdictional utility, but also in the ultimate parent company that is the entity that actually  
10 issues common stock.

11 **Q14. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL**  
12 **FLEXIBILITY?**

13 A14. Yes. Providing an ROE that is sufficient to maintain the Company's ability to attract capital  
14 under reasonable terms, even in times of financial and market stress, is consistent with the  
15 economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield*  
16 decisions, as well as customers' best interests. Supportive policies that address regulatory  
17 lag and allow the utility the opportunity to earn a fair ROE also leads to lower costs for  
18 customers.

19 The allowed ROE and other regulatory features are key determinants of the cash  
20 flows that support Kentucky Power's financial metrics and credit standing. As evidenced  
21 by S&P's 2023 downgrade of the Company, a weakening financial standing ultimately  
22 results in lower credit ratings. Because investors demand a higher return for assuming  
23 greater risk, an erosion in the utility's credit standing leads directly to higher borrowing  
24 costs, as well as a higher required return on equity capital.<sup>7</sup> This additional return is further  
25 magnified during periods of turmoil in capital markets, when risk spreads may widen

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<sup>5</sup> S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

<sup>6</sup> Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at p. 1780.

<sup>7</sup> For example, the average yield spread between utility bonds rated Baa and A-rated bonds averaged 22 basis points during 2024.

1 significantly.<sup>8</sup> Thus, authorizing a fair ROE and providing the utility a reasonable  
2 opportunity to actually earn this return also lowers the cost of borrowing and maintains  
3 access to the capital necessary to provide service. As a result, customers enjoy the benefits  
4 that come from ensuring that the utility has the financial wherewithal to take whatever  
5 actions are required to ensure safe and reliable service.

6 **B. Conclusions and Recommendations**

7 **Q15. WHAT ARE YOUR FINDINGS REGARDING THE JUST AND REASONABLE**  
8 **ROE FOR KENTUCKY POWER?**

9 A15. Considering the economic requirements necessary to support continuous access to capital  
10 under reasonable terms and the results of my analysis, I conclude that 10.5% represents a  
11 fair ROE for Kentucky Power's electric utility operations. The support for my conclusion  
12 is summarized below:

- 13 • In order to reflect the risks and prospects associated with Kentucky  
14 Power's utility business, I predicate my analysis on a proxy group of 20  
15 publicly traded electric utilities.
- 16 • Because investors' required ROE is unobservable and no single method  
17 should be viewed in isolation, I apply the DCF, CAPM, ECAPM, and  
18 risk premium methods to estimate a just and reasonable ROE for  
19 Kentucky Power, as well as referencing the expected earnings approach.
- 20 • As summarized on Exhibit AMM-2, based on the results of these  
21 analyses and giving less weight to extremes at the high and low ends of  
22 the range, I conclude that the cost of equity for a regulated electric utility  
23 is in the 10.0% to 11.0% range.
- 24 • My ROE recommendation for Kentucky Power's electric operations is  
25 the midpoint of this range, or 10.5%.
- 26 • Continued support for Kentucky Power's financial integrity is  
27 imperative to ensure that the Company has the capability to confront  
28 challenges associated with funding infrastructure development  
29 necessary to meet the needs of its customers, even during times of  
30 capital market turmoil.

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<sup>8</sup> In March 2009 the yield spread between utility bonds rated Baa and A-rated bonds rose to 158 basis points, more than seven times the 2024 average.

**Q16. WHAT DO THE DCF RESULTS FOR YOUR SELECT GROUP OF NON-UTILITY FIRMS INDICATE WITH RESPECT TO YOUR EVALUATION?**

A16. 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 range from 10.1% to 10.5%. Although I do not base my recommendations on these results, they confirm that an ROE of 10.5% falls in a reasonable range to maintain Kentucky Power's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

**Q17. WHAT IS YOUR CONCLUSION REGARDING THE REASONABLENESS OF THE 10.0% ROE REQUESTED BY THE COMPANY?**

A17. The 10.0% ROE requested by Kentucky Power is significantly less than the 10.5% midpoint supported by my evidence. As a result, I believe it understates the current cost of equity to the Company. The 10.0% request falls at the very bottom of my cost of equity range, but it nevertheless represents an increase from the 9.75% ROE 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 a 10.5% ROE for Kentucky Power 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 posed by the Company's relatively high concentration of industrial customers and financial leverage.
- Flotation costs associated with issuing common stock are a legitimate expense incurred to raise equity capital supporting Kentucky Power's investment in utility infrastructure. Although I did not include an adjustment for flotation costs, this is another legitimate consideration that supports the reasonableness of the Company's requested ROE.

These findings further indicate that a 10.0% ROE for Kentucky Power is reasonable.

**Q18. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?**

A18. Based on my evaluation, I conclude that the Company's proposed common equity ratio of 46.13% represents a reasonable basis from which to calculate Kentucky Power's overall rate of return. This conclusion was based on the following findings:

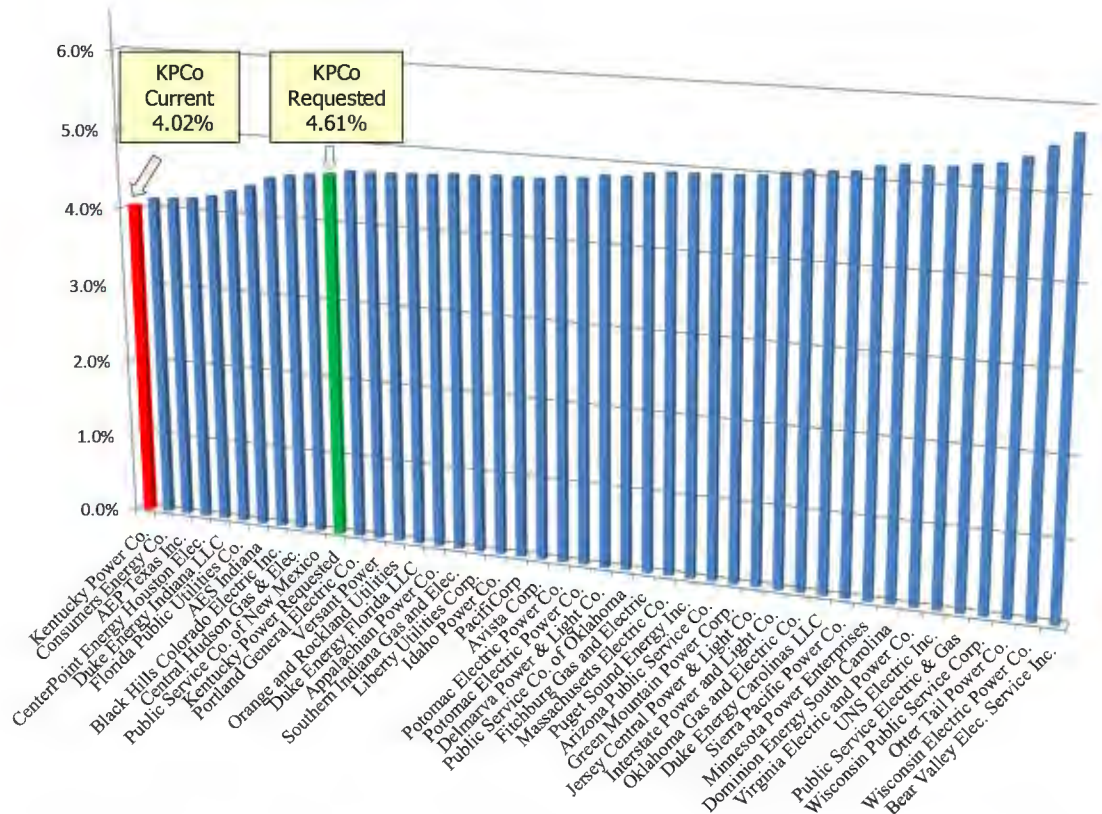
- Kentucky Power's common equity ratio is well within the range of capitalizations maintained by other electric utility operating companies and the firms in the proxy group based on data at year-end 2024 and near-term expectations.
- The Company's proposed equity ratio is also below the average equity ratio of 51.7% maintained by these comparable electric utility operating 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 customers.

**Q19. HOW DOES KENTUCKY POWER'S REQUESTED 4.61% WEIGHTED COST OF EQUITY COMPARE WITH THOSE RECENTLY APPROVED FOR ELECTRIC UTILITIES IN OTHER JURISDICTIONS?**

A19. The bar chart below shows the weighted costs of equity approved by state regulators for investor-owned electric utilities across the country during 2024 and for the first quarter of 2025. 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:



## 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 (Apr. 25 & Feb. 4, 2025). 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, Kentucky Power's current weighted ROE falls at the bottom of the range when compared to recent awards for other electric utilities. When the Company's requested capital structure is considered along with the requested ROE of 10.0%, the resulting weighted cost of equity of 4.61% for Kentucky Power falls continues to fall at the lower end of the distribution of weighted costs of equity allowed by state regulators for other electric utilities.<sup>9</sup>

<sup>9</sup> Unlike Kentucky Power, which is an integrated electric utility, certain of the observations reflected in Figure AMM-1 are for distribution-only utilities.

### **III. FUNDAMENTAL ANALYSES**

#### **Q20. WHAT IS THE PURPOSE OF THIS SECTION?**

A20. This section briefly reviews the operations and finances of Kentucky Power. As a predicate to my quantitative analyses, I also examine specific conditions impacting today's capital markets. 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, which form the basis of a just and reasonable ROE.

#### **A. Kentucky Power**

#### **Q21. BRIEFLY DESCRIBE KENTUCKY POWER AND ITS UTILITY OPERATIONS.**

A21. Organized in Kentucky in 1919 and headquartered in Ashland, Kentucky, the Company is a wholly-owned operating subsidiary of AEP. Kentucky Power is engaged in the generation, transmission, and distribution of electric power to approximately 162,000 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, 2024, Kentucky Power's total assets amounted to \$3.3 billion, with annual revenues amounting to approximately \$696 million.<sup>10</sup>

During 2024, sales to residential customers accounted for approximately 40% of total revenues, with 27% from commercial customers, 24% from industrial consumers, and 6% attributable to wholesale sales. Kentucky Power owns 1,075 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 11,400 miles of transmission and distribution lines. The Company is a member of PJM, a regional transmission organization approved by FERC, and provides transmission service pursuant to the PJM Open Access Transmission Tariff. Kentucky Power's retail utility operations are subject to the

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<sup>10</sup> The information in this section is sourced from *Kentucky Power Co., 2024 Annual Report, Kentucky Power Fact Sheet* (2024v4), and AEP Form 10-K for the fiscal year ended December 31, 2024.

jurisdiction of the Commission, with wholesale transmission operations being regulated by FERC.

**Q22. PLEASE DESCRIBE THE AEP SYSTEM.**

A22. AEP delivers electricity to approximately 5.6 million customers across eleven states. AEP is one of the largest electric utilities in the U.S., with its combined utility system including approximately 29,000 MW of generating capacity, 40,000 miles of transmission lines, and 225,000 miles of distribution lines. Coal-fired power plants accounted for approximately 40% of AEP's total generation in 2024, with 22% from natural gas, 22% from nuclear, and the remaining 16% from renewable sources. AEP's revenues totaled approximately \$19.7 billion in the most recent fiscal year, with total assets at year-end 2024 of \$103.1 billion.

**Q23. WHERE DOES KENTUCKY POWER OBTAIN THE CAPITAL USED TO FINANCE ITS INVESTMENT IN UTILITY PLANT?**

A23. As a wholly-owned subsidiary of AEP, the Company obtains common equity capital solely from its parent, whose common stock is publicly traded on the Nasdaq. In addition to capital supplied by AEP, the Company also issues debt securities directly under its own name and has been assigned issuer ratings of Baa3 by Moody's and BBB by S&P. Meanwhile, Fitch has assigned an issuer rating of BBB to Kentucky Power.

**Q24. DOES KENTUCKY POWER ANTICIPATE THE NEED FOR ADDITIONAL CAPITAL GOING FORWARD?**

A24. Yes. Kentucky Power will require capital investment to accomplish necessary maintenance and replacements of its utility infrastructure, as well as to fund investment in new facilities. Capital expenditures are expected to total approximately \$1.4 billion over the 2025 to 2029 period.<sup>11</sup>

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<sup>11</sup> American Electric Power Co., *June Investor Meetings* (Mar. 3-4, 2025) at 16, [https://docs.aep.com/docs/investors/events/presentationsandwebcasts/June\\_Investor\\_Meetings-Handout-6-2025.pdf](https://docs.aep.com/docs/investors/events/presentationsandwebcasts/June_Investor_Meetings-Handout-6-2025.pdf) (last visited July 16, 2025).

1 **B. Outlook for Capital Costs**

2 **Q25. PLEASE SUMMARIZE CURRENT ECONOMIC AND CAPITAL MARKET**  
3 **CONDITIONS.**

4 A25. Following the economic contraction stemming from the COVID-19 pandemic in 2020,  
5 U.S. real GDP improved significantly in 2021, with GDP growing at a pace of 5.7%.<sup>12</sup>  
6 Economic growth was more subdued in subsequent years, falling in a range of 2.5% to  
7 2.9% between 2022 and 2024.<sup>13</sup> More recently, real GDP decreased an annual rate of 0.2%  
8 in the first quarter of 2025.<sup>14</sup> Meanwhile, indicators of employment have remained in a  
9 narrow range of 4.0% to 4.2% since May 2024.<sup>15</sup>

10 The underlying risk and price pressures associated with the COVID-19 pandemic  
11 were overshadowed by a dramatic increase in global uncertainties following Russia's  
12 invasion of Ukraine in February 2022. Geopolitical risks have been compounded by the  
13 resurgence of conflict in the Middle East. Apart from disrupting global trade, the potential  
14 for escalation has prompted concerns over potential constraints to crude oil supplies and  
15 resulting supply-side price shocks that could reignite inflation and further dampen  
16 economic growth.

17 Stimulative monetary and fiscal policies instituted in response to the COVID-19  
18 pandemic, coupled with supply-chain disruptions and rapid price rises in the energy and  
19 commodities markets, led to increasing concern that inflation would remain significantly  
20 above the Federal Reserve's longer-run benchmark of 2%. CPI inflation peaked in June  
21 2022 at 9.1%, its highest level since November 1981. CPI inflation has moderated

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<sup>12</sup> U.S. Dep't of Commerce, Bureau of Economic Analysis, <https://www.bea.gov/news/2022/gross-domestic-product-fourth-quarter-and-year-2021-second-estimate> (last visited Mar. 12, 2025).

<sup>13</sup> U.S. Dep't of Commerce, Bureau of Economic Analysis, <https://www.bea.gov/sites/default/files/2025-05/gdp1q25-2nd.pdf> (last visited June 26, 2025).

<sup>14</sup> U.S. Dep't of Commerce, Bureau of Economic Analysis, <https://www.bea.gov/news/2025/gross-domestic-product-second-estimate-corporate-profits-preliminary-estimate-1st-quarter> (last visited June 26, 2025).

<sup>15</sup> News Release, U.S. Dep't of Labor, Bureau of Labor Statistics, *The Employment Situation—June 2025* (Jul. 3, 2025), <https://www.bls.gov/news.release/pdf/empstat.pdf> (last visited July 17, 2025).

1 significantly since then, but increased somewhat to 2.7% in June 2025,<sup>16</sup> which exceeds  
2 the Federal Reserve’s 2.0% target. The so-called “core” price index, which excludes more  
3 volatile energy and food costs, rose at an annual rate of 2.9% in June 2025.<sup>17</sup> PCE inflation  
4 ticked up to 2.3% in May 2025, or 2.7% after excluding more volatile food and energy  
5 costs.<sup>18</sup>

6 The investment community has expressed growing concern that rising import tariffs  
7 and the potential for severe disruptions to global commerce may reignite inflation and lead  
8 to economic recession. President Trump’s announcement in early April 2025 of  
9 far-reaching import tariffs on nearly all U.S. trading partners was followed shortly after by  
10 a 90-day reprieve on certain “reciprocal” tariffs. The result was one of the most volatile  
11 periods on record in the equity markets, with major stock market indices whipsawed as  
12 investors struggle to decipher the impact of rapidly changing trade policies on economic  
13 growth and corporate profits. The debt markets were also impacted by the threat to global  
14 trade and finance, with uncharacteristic selling in U.S. Treasury bonds further unsettling  
15 investors. Oscillating trade war developments have also precipitated an erosion of  
16 consumer confidence, with the University of Michigan consumer sentiment index in May  
17 2025 remaining about 20% below December 2024 levels.<sup>19</sup> Investors continue to face the  
18 prospect of heightened market volatility as capital markets respond to these uncertainties.

19 **Q26. HAVE THESE DEVELOPMENTS IMPACTED THE RISKS FACED BY**  
20 **UTILITIES AND THEIR INVESTORS?**

21 A26. Yes. In February 2024, S&P revised its outlook for the utility sector to “negative,” noting  
22 that:

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<sup>16</sup> U.S. Dep’t of Labor, Bureau of Labor Statistics, *Consumer Price Index Summary* (Jul. 15, 2025), <https://www.bls.gov/news.release/cpi.nr0.htm> (last visited July 17, 2025).

<sup>17</sup> *Id.*

<sup>18</sup> Bureau of Economic Analysis, *Personal Income and Outlays, May 2025*, BEA 25-25 (June 27, 2025), <https://www.bea.gov/news/2025/personal-income-and-outlays-may-2025> (last visited July 17, 2025).

<sup>19</sup> University of Michigan, *Surveys of Consumers* (June 2025). <http://www.sca.isr.umich.edu/> (last visited Jun. 26, 2025).

Credit quality for North American investor-owned regulated utilities has weakened over the past four years, with downgrades outpacing upgrades by more than three times. We expect downgrades to again surpass upgrades in 2024 for the fifth consecutive year.<sup>20</sup>

More recently, S&P affirmed their negative outlook, citing to rising physical risks, as well as weakening financial measures due to “record-breaking capital spending” and cash flow deficits, and noting “the industry’s high percentage of companies . . . that operate with only minimal financial cushion from their downgrade threshold.”<sup>21</sup> Meanwhile, Moody’s cautioned that widening cash flow deficits in the utility industry were placing increasing negative pressure on financial credit metrics, concluding that credit pressure “will likely continue to lead to negative rating actions if not sufficiently mitigated.”<sup>22</sup>

Utilities are also exposed to supply chain risk and procurement cost management associated with increasing tariff barriers to trade. In 2024, China accounted for over 50% of low-voltage transformer imports, while Mexico is the largest trading partner for medium and high-voltage transformers.<sup>23</sup> Utilities in the U.S. also rely heavily on imports from China, Canada, and Mexico for breakers and switchgear. Wood Mackenzie, a global data and analytics provider for the energy industry, noted that:

This critical path aspect of transmission and distribution projects has already faced tremendous security of supply and cost pressure the past five years with increased competition for the materials with the rise of renewables and transmission & distribution construction, increased storm response and volatile metals markets. . . . The additional cost pressure from tariffs coupled with supply pressure via new electric generation assets to support AI data centres, and a shift of federal investments from renewables builds to T&D infrastructure may exacerbate what the last five years have been.<sup>24</sup>

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<sup>20</sup> S&P Global Ratings, *Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens*, Criteria Corporates (Feb. 14, 2024).

<sup>21</sup> S&P Global Ratings, *Regulated Utilities: Credit risks are rising*, Industry Credit Outlook Update – North America (July 18, 2024).

<sup>22</sup> Moody’s Investors Service, *Electric and Gas Utilities – US*, Sector In-Depth (Oct. 21, 2024).

<sup>23</sup> Wood MacKenzie, *Navigating the impact of President Trump’s tariffs on utility supply chains* (Jan. 16, 2025), <https://www.woodmac.com/news/opinion/the-impact-of-proposed-tariffs-on-utility-supply-chains/> (last visited Mar. 17, 2025).

<sup>24</sup> *Id.*

Apart from contributing to higher prices for materials and equipment, supply chain disruptions and shortages have the potential to delay necessary construction and maintenance of utility infrastructure.

**Q27. DO RECENT TRENDS INDICATE THAT THE COST OF EQUITY HAS INCREASED RELATIVE TO THE RECENT PAST?**

A27. Yes. Although the cost of equity is not observable, interest rates provide a gauge for the direction of capital costs, including required returns on common stocks. Figure AMM-2 below compares widely referenced capital market benchmarks in June 2025 with average levels for 2021.

**FIGURE AMM-2  
CAPITAL MARKET BENCHMARKS**

<b>Series</b>	<b>2021</b>	<b>June 2025</b>	<b>Change (bps)</b>
10-Year Treasury Bonds	1.44%	4.38%	294
30-Year Treasury Bonds	2.05%	4.89%	284
Baa Utility Bonds	3.35%	6.13%	278
Prime Loan Rate	3.25%	7.50%	425
Federal Funds Rate	0.13%	4.38%	425

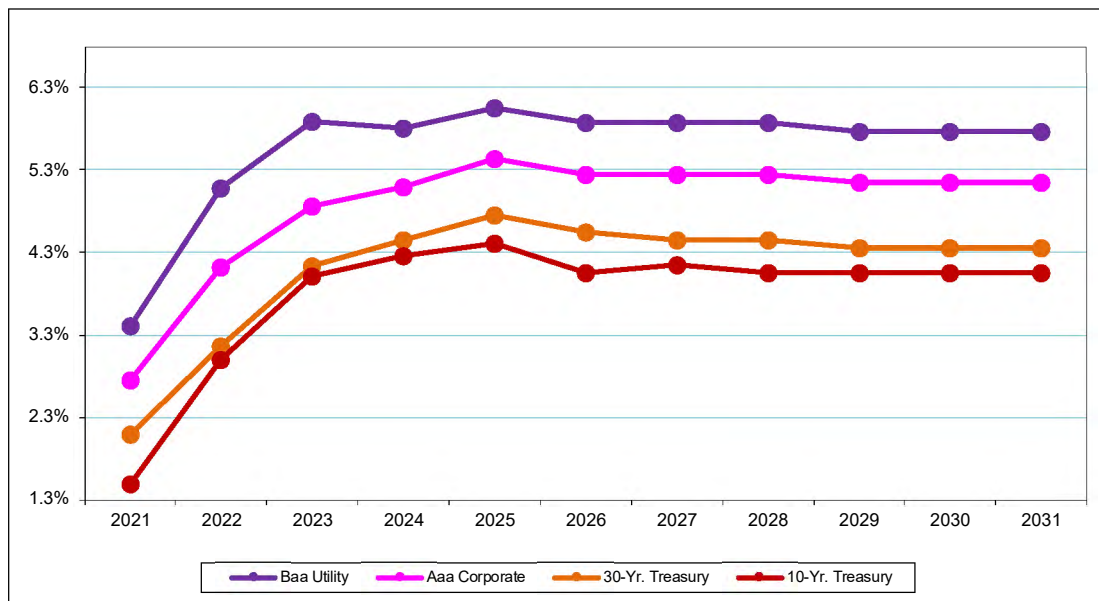
Source: <https://fred.stlouisfed.org>; Moody's Credit Trends.

As shown above, trends in bond yields since 2021 document a substantial increase in the returns on long-term capital demanded by investors. With respect to utility bond yields—which is the most relevant indicator for the Company's common equity investors—the average yield in June 2025 is almost 280 basis points above the level prevailing during 2021.

1 **Q28. DO INVESTORS ANTICIPATE THAT THESE HIGHER BOND YIELDS WILL BE**  
2 **SUSTAINED?**

3 A28. Yes. As illustrated in Figure AMM-3 below, the most recent long-term consensus  
4 projections from top economists published by Blue Chip document that long-term bond  
5 yields are expected to remain elevated when compared to recent historical levels.

6 **FIGURE AMM-3**  
7 **INTEREST RATE TRENDS**



Source: Moody's Investors Service; <https://fred.stlouisfed.org/>; Wolters Kluwer, Blue Chip Financial Forecasts (Jun. 2, 2025).

8 This evidence shows that long-term capital costs—including the ROE—have increased  
9 substantially since 2021, and that investors expect these higher capital costs to be sustained  
10 at least through 2031.

11 **Q29. WHAT DO THESE TRENDS INDICATE REGARDING A FAIR ROE FOR**  
12 **KENTUCKY POWER?**

13 A29. The upward move in interest rates suggests that long-term capital costs—including the cost  
14 of equity—have increased significantly in recent years. Exposure to higher interest rates,  
15 inflation, and capital expenditure requirements also reinforce the importance of buttressing  
16 the Company's credit standing. Considering the potential for financial market instability,



1 competition with other investment alternatives, and investors' sensitivity to risk exposures  
2 in the utility industry, credit strength is a key ingredient in maintaining access to capital at  
3 reasonable cost.

4 If the upward shift in investors' risk perceptions and required rates of return for  
5 long-term capital is not incorporated in the allowed ROE, the results will fail to meet the  
6 comparable earnings standard that is fundamental in determining the cost of capital. From  
7 a more practical perspective, failing to provide investors with the opportunity to earn a rate  
8 of return commensurate with Kentucky Power's risks will weaken its financial integrity  
9 and undermine its ability to attract necessary capital.

#### **IV. COMPARABLE RISK PROXY GROUP**

10 **Q30. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

11 A30. This section explains the basis of the proxy group of publicly traded companies I use to  
12 estimate the cost of equity, examines alternative objective indicators of investment risk for  
13 these firms, and compares the investment risks applicable to Kentucky Power with my  
14 reference group.

15 **A. Determination of the Proxy Group**

16 **Q31. HOW DO YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE**  
17 **COST OF COMMON EQUITY FOR KENTUCKY POWER?**

18 A31. Estimating the cost of common equity using quantitative methods requires observable  
19 capital market data, such as stock prices and beta values. Even for a firm with publicly  
20 traded stock, the cost of common equity can only be estimated and the results of  
21 quantitative models inherently include some degree of error. The accepted approach to  
22 increase confidence in the results is to apply quantitative methods to a proxy group of  
23 publicly traded companies that investors regard as risk comparable. The results of the  
24 analysis on the sample of companies are relied upon to establish a range of reasonableness  
25 for the cost of equity for the specific company at issue.

**Q32. HOW DO YOU IDENTIFY THE PROXY GROUP OF ELECTRIC UTILITIES USED IN YOUR ANALYSES?**

A32. To reflect the risks and prospects associated with Kentucky Power's jurisdictional electric operations, I apply the following criteria to identify a proxy group of utilities:

1. Included in the Electric Utility Industry groups compiled by Value Line.
2. Paid common dividends over the last six months and have not announced a dividend cut since that time.
3. 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+.

These criteria result in a proxy group composed of 20 companies, which I refer to as the "Utility Group."

**B. Relative Risks of the Utility Group and Kentucky Power**

**Q33. DO YOU EVALUATE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY GROUP?**

A33. Yes. My evaluation of relative risk considers four published benchmarks that are widely relied on in the investment community. 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 all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is 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.

1           Although credit ratings provide the most widely referenced benchmark for  
2 investment risks, the quality rankings published by Value Line provide an important and  
3 objective assessment of relative risks that are considered by investors in forming their  
4 expectations and measure the risks associated with common stocks. Value Line's primary  
5 risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This  
6 overall risk measure is intended to capture the total risk of a stock and incorporates  
7 elements of stock price stability and financial strength. Given that Value Line is perhaps  
8 the most widely available source of investment advisory information, its Safety Rank  
9 provides useful guidance regarding the risk perceptions of investors.

10           The Financial Strength Rating is designed as a guide to overall financial strength  
11 and creditworthiness, with the key inputs including financial leverage, business volatility  
12 measures, and company size. Value Line's Financial Strength Ratings range from "A++"  
13 (strongest) down to "C" (weakest) in nine steps. These objectives, published indicators  
14 incorporate consideration of a broad spectrum of risks, including financial and business  
15 position, relative size, and exposure to firm-specific factors.

16           Finally, beta measures a utility's stock price volatility relative to the market as a  
17 whole and reflects the tendency of a stock's price to follow changes in the market. A stock  
18 that tends to respond less to market movements has a beta less than 1.00, while stocks that  
19 tend to move more than the market have betas greater than 1.00. Beta is the only relevant  
20 measure of investment risk under modern capital market theory and is widely cited in  
21 academics and in the investment industry as a guide to investors' risk perceptions.  
22 Moreover, in my experience Value Line is the most widely referenced source for beta in  
23 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.<sup>25</sup>

**Q34. HOW DOES THE OVERALL RISK OF YOUR PROXY GROUP COMPARE TO KENTUCKY POWER?**

A34. Figure AMM-4 compares the Utility Group to 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:

**FIGURE AMM-4  
COMPARISON OF RISK INDICATORS**

	Moody's	S&P	Value Line		
			Safety Rank	Financial Strength	Beta
Utility Group	Baa2	BBB+	2	A	0.80
Kentucky Power	Baa3	BBB	1	A	0.70

The average Moody's and S&P credit ratings corresponding to the Utility Group are higher than for Kentucky Power, which indicates that the Company is viewed as having somewhat greater 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.<sup>26</sup> Considered together, a comparison of these objective measures indicates that investors would likely conclude that the overall investment risks for the firms in the Utility Group are generally comparable to those of Kentucky Power.

<sup>25</sup> Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 71.

<sup>26</sup> AEP is rated Baa2 and BBB+ by Moody's and S&P, 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.

**Q35. HOW DOES KENTUCKY POWER’S RATING PROFILE COMPARE WITH  
THE ELECTRIC UTILITY INDUSTRY MORE GENERALLY?**

A35. 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 five of the 188 rated companies having higher risk than the Company.<sup>27</sup> Similarly, the BBB ratings assigned by S&P and Fitch rank Kentucky Power below ratings for other utilities, which are predominantly rated A- or BBB+. <sup>28</sup> 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.<sup>29</sup>

**Q36. ARE THERE OTHER PRESSURES THAT HAVE PARTICULAR  
SIGNIFICANCE FOR KENTUCKY POWER?**

A36. Yes. The Company’s service territory generally faces weaker 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.”<sup>30</sup> With respect to Kentucky Power specifically, Moody’s cited low educational attainment and income, below-average worker productivity, and a struggling manufacturing sector as limiting factors leading to challenging economic conditions in the Company’s service territory.<sup>31</sup> Moody’s cautioned investors that “the KPSC’s decisions are often impacted by the weak

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<sup>27</sup> Moody’s Investors Service, *Regulated Electric and Gas Utilities – US, Outlook stable; regulatory support, economic factors offset financial pressure*, Outlook (Nov. 7, 2024).

<sup>28</sup> See, e.g., Fitch Ratings, Inc., *North American Integrated Utilities—Relative Credit Analysis* (Dec. 2024).

<sup>29</sup> S&P Global Ratings, *Issuer Ranking: North American Electric, Gas, And Water Regulated Utilities, Strongest To Weakest*, RatingsDirect (Jan. 10, 2023).

<sup>30</sup> Moody’s Investors Service, *2023 outlook negative due to higher natural gas prices, inflation and rising interest rates*, Outlook (Nov. 10, 2022).

<sup>31</sup> Moody’s Investors Service, *Kentucky Power*, Credit Opinion (Mar. 11, 2025).

1 economic conditions in KPCo’s service territory resulting in rate orders that are sometimes  
2 less supportive of utility credit quality.”<sup>32</sup> Similarly, Fitch cited the Company’s  
3 “economically challenged service territory” as a key factor contributing to weakened credit  
4 metrics, noting that Kentucky Power’s “residential customer count has declined about 6%  
5 over the last decade, while large commercial and industrial customer numbers have  
6 declined around 20%.”<sup>33</sup>

7 Investors also recognize that Kentucky Power’s service area is characterized by a  
8 high concentration of sales to industrial customers relative to other electric utilities. During  
9 2024, approximately 24% of the Company’s total revenues were to industrial customers,<sup>34</sup>  
10 versus an average of 15% for the firms in the Utility Group. Further aggravating the risks  
11 of this exposure, during 2024, 15% of Kentucky Power’s revenues were attributable to a  
12 single customer, Marathon Petroleum Company.<sup>35</sup> Because these sales are more sensitive  
13 to business cycle changes, the price of alternative energy sources, and pressure from  
14 competitors, they are generally considered to be more risky than sales to residential or  
15 commercial customers.<sup>36</sup> As S&P recognized, “KPCo derives about 30% of its energy sales  
16 from industrial customers, which leads to somewhat less stability in its operating cash  
17 flow.”<sup>37</sup> This exposure to a relatively high concentration of industrial sales implies a  
18 significant degree of risk to Kentucky Power’s operations that must be offset by sufficient  
19 financial fitness.

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<sup>32</sup> *Id.*

<sup>33</sup> Fitch Ratings, *Kentucky Power Company*, Rating Report (Dec. 10, 2024).

<sup>34</sup> Kentucky Power Company, 2024 Annual Report at 55.

<sup>35</sup> *Id.* at 12.

<sup>36</sup> 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).

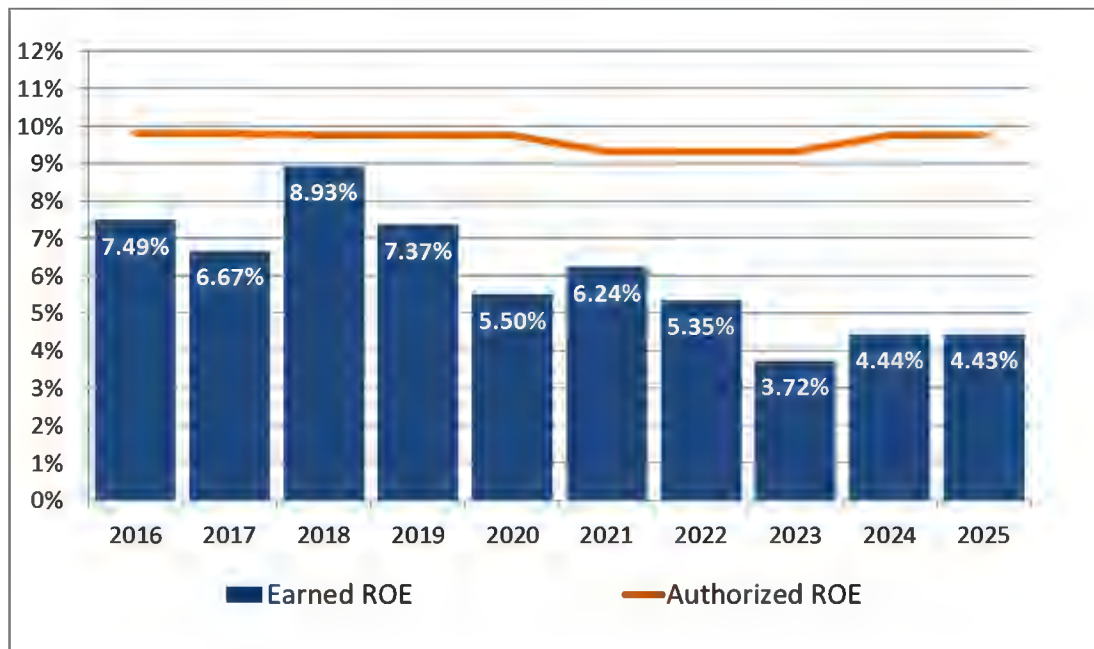
<sup>37</sup> S&P Global Ratings, *Kentucky Power Co.*, RatingsDirect (Sept. 19, 2024).

**Q37. WOULD INVESTORS ALSO HAVE CONCERNS REGARDING THE  
POTENTIAL FOR ATTRITION AND REGULATORY LAG ASSOCIATED WITH  
KENTUCKY POWER'S OPERATIONS?**

A37. Yes. Attrition is the deterioration of the actual return below the allowed return that occurs when the relationships between revenues, costs, and rate base used to establish rates do not 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 growth in the utility's investment outstrips the rate base used for ratemaking, the earned rate of return will fall below the allowed return through no fault of the utility's management. These imbalances are exacerbated as the regulatory lag increases between the time when the data used to establish rates is measured and the date when the rates go into effect.

As discussed in the testimony of Company Witness Newcomb, regulatory lag and attrition have been ongoing issues for Kentucky Power and the Company has been chronically unable to earn its authorized return. Figure AMM-5 below compares Kentucky Power's actual earned ROE with its authorized ROE from 2016 to June 30, 2025.

**FIGURE AMM-5  
EARNED VERSUS AUTHORIZED ROE**



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, with Moody’s noting that Kentucky Power “has generated weak cash flow and cash flow-based credit metrics in recent years” and concluding that an increase in regulatory lag could lead to a downgrade.<sup>38</sup> As the Commission has recognized, “with the relative decline of industry and the economy in eastern Kentucky generally, Kentucky Power has struggled to achieve its allowed ROE.”<sup>39</sup>

**Q38. WOULD INVESTORS ALSO CONSIDER THE IMPLICATIONS OF REGULATORY MECHANISMS IN EVALUATING A UTILITY’S RELATIVE RISKS?**

A38. Yes. Regulatory adjustment mechanisms have important implications for a utility’s financial health and relative risk. Decoupling mechanisms, cost trackers, and future test

<sup>38</sup> Moody’s Investors Service, *Kentucky Power Company*, Credit Opinion (Mar. 11, 2025).

<sup>39</sup> Order at 50, *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 (%) All Other Required Approvals And Relief*, Case No. 2020-00174 (Ky. P.S.C. Jan. 13, 2021).



1 years have become increasingly prevalent in the industry in recent years, along with  
2 alternatives to traditional ratemaking such as formula rates and multi-year rate plans. RRA  
3 concluded in its most recent review of adjustment clauses that:

4 More recently and with greater frequency, commissions have approved  
5 mechanisms that permit the costs associated with the construction of new  
6 generation or delivery infrastructure to be used, effectively including these  
7 items in rate base without the need for a full rate case. In some instances,  
8 these mechanisms may even provide the utilities a cash return on  
9 construction work in progress.

10 . . . [C]ertain types of adjustment clauses are more prevalent than others.  
11 For example, those that address electric fuel and gas commodity charges are  
12 in place in all jurisdictions. Also, about two-thirds of all utilities have riders  
13 in place to recover costs related to energy efficiency programs, and roughly  
14 half of the utilities have some type of decoupling mechanism in place.<sup>40</sup>

15 As shown on Exhibit AMM-3, the companies in my Utility Group operate under a  
16 wide variety of cost adjustment mechanisms, which encompass revenue decoupling and  
17 adjustment clauses designed to address rising capital investment outside of a traditional  
18 rate case, increasing costs of environmental compliance measures, as well as riders to  
19 address the costs of energy conservation programs, bad debt expenses, certain taxes and  
20 fees, post-retirement employee benefit costs, and transmission-related charges.

21 **Q39. WHAT REGULATORY MECHANISMS BEEN APPROVED FOR KENTUCKY**  
22 **POWER?**

23 A39. In addition to a fuel adjustment clause, the Commission has approved a surcharge for the  
24 Company that allows for recovery of environmental compliance costs applicable to  
25 coal-fired generating facilities. Kentucky Power also operates under a DSM rate  
26 mechanism that provides for recovery of the full costs associated with related programs, as  
27 well as a rider to address certain retirement costs associated with Big Sandy Units 1 and 2  
28 (the “Decommissioning Rider”). However, in Case No. 2020-00174, the Commission

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<sup>40</sup> S&P Global Market Intelligence, *Adjustment Clause: A state-by-state overview*, RRA Regulatory Focus (July 18, 2022).

1 prescribed a 10 basis point reduction in the ROE to be applicable to rider revenue  
2 requirement calculations, eroding the benefit of these mechanisms.

3 As discussed in the testimony of Company Witness Wolfram, Kentucky Power is  
4 also requesting approval of a rider to facilitate recovery of the remaining net book value  
5 associated with the Company's investment in the Mitchell Plant units.

6 **Q40. WHAT DO THESE CHARACTERISTICS IMPLY WITH RESPECT TO THE**  
7 **COMPANY'S RISKS RELATIVE TO OTHER UTILITIES IN GENERAL?**

8 A40. Investors recognize that the use of adjustment mechanisms is widely prevalent in the utility  
9 industry and consider the impact of these provisions in forming their expectations and risk  
10 perceptions for the firms in the Utility Group. Although the Company's existing regulatory  
11 mechanisms would be regarded as supportive, in contrast to many of the specific operating  
12 companies associated with the firms in the Utility Group, Kentucky Power does not operate  
13 under a revenue decoupling mechanism or cost trackers to address ongoing investment in  
14 electric utility infrastructure. Thus, the Company's continued exposure to the uncertainties  
15 of revenue variability and regulatory lag would imply a greater level of risk than is faced  
16 by other utilities, including the firms in the Utility Group.<sup>41</sup>

17 **Q41. WHAT OTHER CONSIDERATIONS ARE RELEVANT TO INVESTORS'**  
18 **ASSESSMENT OF KENTUCKY POWER?**

19 A41. Notwithstanding the environmental recovery riders approved for the Company, Moody's  
20 concluded that Kentucky Power remains exposed to elevated carbon transition risks due to  
21 its significant coal-fired generation.<sup>42</sup> Similarly, S&P has noted that a key risk for the

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<sup>41</sup> Although I reference corporate credit ratings in evaluating a risk-comparable proxy group, these indicators are focused on the risk of default associated with a utility's outstanding debt securities. Although debtholders are also concerned about the stability and sufficiency of a utility's cash flows. The implications of attrition and earnings variability are especially relevant to equity investors, who are only entitled to the residual earnings once all other claimants have been paid.

<sup>42</sup> Moody's Investors Service, *Kentucky Power Company*, Credit Opinion (Mar. 11, 2025).

1 Company is “[h]eavy reliance on coal-fired generation [that] increases environmental  
2 compliance exposure.”<sup>43</sup>

3 In addition, Kentucky Power’s capital expenditure requirements also add to the  
4 risks faced by investors. Fitch cited the Company’s increasing capital expenditures as a  
5 key ratings driver, noting that “the company’s five-year plan . . . is a 61% increase from  
6 the 2024 to 2028 plan.”<sup>44</sup>

### 7 C. Capital Structure

#### 8 **Q42. WHAT IS THE ROLE OF CAPITAL STRUCTURE IN SETTING A UTILITY’S** 9 **RATE OF RETURN?**

10 A42. Capital structure reflects the mix of capital—debt, preferred securities, and common  
11 equity—used to finance a utility’s assets. The proportions of the total capitalization  
12 attributable to each source of capital are typically used to weight the costs of investor-  
13 supplied capital in calculating an overall rate of return.

#### 14 **Q43. HOW DO COMPANIES DETERMINE AN APPROPRIATE CAPITAL** 15 **STRUCTURE FOR THEIR OPERATIONS?**

16 A43. There are many considerations in the capital structure decision. In general, the goal is to  
17 employ the mix of capital that minimizes the weighted average cost of capital. Given the  
18 interplay between costs of debt and equity, the impact of taxes, bankruptcy costs, and the  
19 level of business risks, determining a firm’s optimal capital structure is an imprecise  
20 exercise. In practice, capital structure decisions must be made by combining managements’  
21 judgment, numerical analysis, and considering investors’ risk perceptions.

22 It is generally accepted that the norms established by comparable firms provide a  
23 valid benchmark to evaluate a reasonable capital structure for a utility. The capital structure  
24 maintained by other utilities should reflect their collective efforts to finance themselves so  
25 as to minimize capital costs while preserving their financial integrity and ability to attract

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<sup>43</sup> S&P Global Ratings, *Kentucky Power Co.*, RatingsDirect (Sept. 19, 2024).

<sup>44</sup> Fitch Ratings, Inc., *Kentucky Power Company*, Rating Report (Dec. 10, 2024).

capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

**Q44. IS AN EVALUATION OF A UTILITY'S CAPITAL STRUCTURE RELEVANT IN ASSESSING ITS RETURN ON EQUITY?**

A44. 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 a common shareholder's 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.

**Q45. WHAT COMMON EQUITY RATIO IS IMPLICIT IN KENTUCKY POWER'S CAPITAL STRUCTURE?**

A45. Kentucky Power's capital structure is presented in the direct testimony of Company Witness Messner. As summarized in his testimony, the common equity ratio that the Company is using in this case to calculate rates is approximately 46.13%.

**Q46. WHAT ARE THE RELEVANT INDUSTRY BENCHMARKS TO CONSIDER IN EVALUATING KENTUCKY POWER'S CAPITAL STRUCTURE?**

A46. Because this proceeding focuses on the ROE for the regulated utility operations of Kentucky Power, the capital structures of the proxy companies' regulated utility operating companies provide a consistent basis of comparison. Pages 1 and 2 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 ranged from 37.4% to 68.0% and averaged 51.7%; 47 of these 51 operating companies maintained common equity ratios that exceed the 46.13% applicable to Kentucky Power.

**Q47. DOES KENTUCKY POWER’S CAPITAL STRUCTURE FALL WITHIN THE RANGE OF EQUITY RATIOS MAINTAINED BY THE COMPANIES IN THE UTILITY GROUP?**

A47. Yes. As shown on page 3 of Exhibit AMM-4, common equity ratios for the Utility Group ranged from a low of 30.2% to a high of 63.9% at year-end 2024. Also shown on page 4 of Exhibit AMM-4, Value Line expects common equity ratios for the Utility Group to range between 29.0% and 57.5% over its three-to-five year forecast horizon.

**Q48. WHAT OTHER EVIDENCE SUPPORTS THE REASONABLENESS OF THE COMPANY’S REQUESTED CAPITAL STRUCTURE?**

A48. Reference to recent findings for electric utilities in other regulatory proceedings also supports the reasonableness of Kentucky Power’s 46.13% common equity ratio. The figure below presents the range of common equity ratios approved for electric utilities during the eight quarters ending March 31, 2025, as reported by RRA:

**FIGURE AMM-6  
ELECTRIC UTILITY ALLOWED COMMON EQUITY RATIOS**

	<b>Low</b>		<b>High</b>		<b>Average</b>
Q2-23	49.00%	--	50.96%	--	50.96%
Q3-23	48.00%	--	52.25%	--	52.25%
Q4-23	48.00%	--	51.51%	--	51.51%
Q1-24	41.25%	--	49.68%	--	49.68%
Q2-24	44.36%	--	52.26%	--	49.77%
Q3-24	45.57%	--	52.83%	--	50.27%
Q4-24	42.50%	--	56.54%	--	51.29%
Q1-25	41.73%	--	57.00%	--	48.28%
Average	<b>45.05%</b>	<b>--</b>	<b>52.88%</b>	<b>--</b>	<b>50.50%</b>

Source: S&P Global Market Intelligence, Major Rate Case Decisions, RRA Regulatory Focus (Apr. 25, 2025, Feb. 4, 2025, Feb. 6, 2024). Excludes Limited Issuer Riders and capital structures that include cost-free items.

As demonstrated in the figure above, the Company’s requested 46.13% common equity ratio falls well within the range recently approved for other utilities and below the average of 50.50%.

**Q49. DO ONGOING ECONOMIC AND CAPITAL MARKET UNCERTAINTIES ALSO INFLUENCE THE APPROPRIATE CAPITAL STRUCTURE FOR KENTUCKY POWER?**

A49. Yes. Financial flexibility plays a crucial role in ensuring the wherewithal of a utility to meet funding needs, and utilities with higher financial leverage may be foreclosed 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.<sup>45</sup>

More recently, Moody’s emphasized that the utility sector “is likely to continue to generate negative free cash flow and credit quality is likely to suffer unless utilities fund this negative free cash flow appropriately with a balance of debt and equity financing.”<sup>46</sup>

S&P confirmed the financial challenges associated with funding heightened investment in the utility sector, noting that, “[a]bout one-third of the industry is strategically managing their financial performance with only minimal financial cushion,” and warning that “when unexpected risks occur or base-case assumptions deviate from expectations, the utility’s credit quality can weaken.”<sup>47</sup> More recently, S&P added that

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<sup>45</sup> Moody’s Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

<sup>46</sup> Moody’s Investors Service, *Regulated Electric and Gas Utilities – US, Rising capital expenditures will require higher annual equity funding*, Sector In-Depth (Nov. 8, 2023).

<sup>47</sup> S&P Global Ratings, *The Outlook For North American Regulated Utilities Turns Stable* (May 18, 2023).

1 “given the current high percentage of negative outlooks, we anticipate that 2024 will be  
2 another challenging year for the industry’s credit quality.”<sup>48</sup>

3 As a result, the Company’s capital structure must maintain adequate equity to  
4 preserve the flexibility necessary to maintain continuous access to capital even during  
5 times of unfavorable energy or financial market conditions.

6 **Q50. WHAT OTHER FACTORS DO INVESTORS CONSIDER IN THEIR**  
7 **ASSESSMENT OF A COMPANY’S CAPITAL STRUCTURE?**

8 A50. Utilities, including Kentucky Power, are facing significant capital investment plans in order  
9 to continue to provide reliable service to their customers. Coupled with the potential for  
10 turmoil in capital markets, this warrants a stronger balance sheet to deal with an uncertain  
11 environment. As S&P noted:

12 Under our base case, we expect that by 2024 the industry’s capital spending  
13 will exceed \$180 billion. Because of the industry’s continued robust capital  
14 spending, we expect that [the] industry will continue to generate negative  
15 discretionary cash flow. This requires that the industry has consistent  
16 access to the capital markets to finance capital spending and dividends  
17 requirements.<sup>49</sup>

18 More recently, S&P noted that, “[w]ithout a commensurate focus on balance sheet  
19 preservation through equity support of discretionary negative cash flow deficits, limited  
20 financial cushion could give rise to another round of negative rating actions.”<sup>50</sup> Similarly,  
21 Moody’s noted that higher interest rates and the pressure of maintaining credit metrics  
22 while funding capital investments were leading to greater reliance on common equity.<sup>51</sup>  
23 Moody’s concluded that the utility sector “is likely to continue to generate negative free

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<sup>48</sup> S&P Global Ratings, *Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens*, Comments (Feb. 14, 2024).

<sup>49</sup> S&P Global Ratings, *For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The ‘BBB’ Category*, Ratings Direct (Jan. 20, 2022).

<sup>50</sup> S&P Global Ratings, *Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities*, Comments (Sept. 12, 2023).

<sup>51</sup> Moody’s Investors Service, *Regulated Electric and Gas Utilities – US: Rising capital expenditures will require higher annual equity funding*, Sector In-Depth (Nov. 8, 2023).

1 cash flow and credit quality is likely to suffer unless utilities fund this negative free cash  
2 flow appropriately with a balance of debt and equity financing.”<sup>52</sup>

3 In addition, the investment community also considers the impact of other  
4 considerations, such as leases, purchased power agreements, and postretirement benefit  
5 and asset retirement obligations in its evaluation of a utility’s financial standing.  
6 Considering the magnitude of the Company’s ongoing infrastructure investments, a  
7 conservative financial profile is warranted to maintain continuous access to capital under  
8 reasonable terms, even during times of adverse capital market conditions.

9 **Q51. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO KENTUCKY**  
10 **POWER’S CAPITAL STRUCTURE?**

11 A51. Although Kentucky Power’s ratemaking capital structure falls within the range of capital  
12 structure ratios indicated by industry benchmarks, the Company’s common equity ratio  
13 falls below the 51.7% average maintained by other electric operating companies. While I  
14 conclude that the Company’s capital structure represents a reasonable mix of capital  
15 sources from which to calculate Kentucky Power’s overall rate of return, Kentucky  
16 Power’s relatively low common equity ratio implies greater financial risk.

**V. CAPITAL MARKET ESTIMATES AND ANALYSES**

17 **Q52. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

18 A52. This section presents capital market estimates of the cost of equity. First, I address the  
19 concept of the cost of common equity, along with the risk-return tradeoff principle  
20 fundamental to capital markets. I then describe various quantitative analyses I conducted  
21 to estimate the cost of common equity for the Utility Group.

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<sup>52</sup> *Id.*



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A53. 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.

$$k_i = R_f + RP_i$$

where:  $R_f$  = Risk-free rate of return, and  
 $RP_i$  = Risk premium required to hold riskier asset i.

A54. Yes. The risk-return tradeoff can be documented in the debt markets, where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Comparing the observed yields on Treasury bonds, which are considered free of default risk, to the yields on corporate bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

**Q55. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?**

A55. Yes. It is widely accepted that the risk-return tradeoff 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. Nevertheless, there is every reason to believe that investors demonstrate risk aversion in deciding whether to hold common stocks and other assets, just as when choosing among fixed-income securities.

**Q56. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?**

A56. 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, remaining 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.

**Q57. WHAT ARE THE CHALLENGES IN DETERMINING A JUST AND REASONABLE ROE FOR A REGULATED UTILITY?**

A57. The actual return that equity 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

1 of other accepted methodologies for estimating the cost of equity and the ranges produced  
2 by these approaches can vary widely.

3 **Q58. IS IT CUSTOMARY TO CONSIDER THE RESULTS OF MULTIPLE**  
4 **APPROACHES WHEN EVALUATING A JUST AND REASONABLE ROE?**

5 A58. Yes. Financial analysts and regulators routinely consider the results of alternative  
6 approaches in evaluating a fair ROE. No single method can be regarded as failsafe, with  
7 all approaches having advantages and shortcomings. As FERC has noted, “[t]he  
8 determination of rate of return on equity starts from the premise that there is no single  
9 approach or methodology for determining the correct rate of return.”<sup>53</sup> Similarly, a  
10 publication of the Society of Utility and Regulatory Financial Analysts concluded that:

11 Each model requires the exercise of judgment as to the reasonableness of  
12 the underlying assumptions of the methodology and on the reasonableness  
13 of the proxies used to validate the theory. Each model has its own way of  
14 examining investor behavior, its own premises, and its own set of  
15 simplifications of reality. Each method proceeds from different  
16 fundamental premises, most of which cannot be validated empirically.  
17 Investors clearly do not subscribe to any singular method, nor does the stock  
18 price reflect the application of any one single method by investors.<sup>54</sup>

19 As this treatise succinctly observed, “no single model is so inherently precise that  
20 it can be relied on solely to the exclusion of other theoretically sound models.”<sup>55</sup> Similarly,  
21 *New Regulatory Finance* concluded that:

---

<sup>53</sup> *Northwest Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 4 (1997).

<sup>54</sup> David C. Parcell, *The Cost of Capital – A Practitioner’s Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 84.

<sup>55</sup> *Id.*

1 There is no single model that conclusively determines or estimates the  
2 expected return for an individual firm. Each methodology possesses its own  
3 way of examining investor behavior, its own premises, and its own set of  
4 simplifications of reality. Each method proceeds from different  
5 fundamental premises that cannot be validated empirically. Investors do  
6 not necessarily subscribe to any one method, nor does the stock price reflect  
7 the application of any one single method by the price-setting investor.  
8 There is no monopoly as to which method is used by investors. In the  
9 absence of any hard evidence as to which method outdoes the other, all  
10 relevant evidence should be used and weighted equally, in order to  
11 minimize judgmental error, measurement error, and conceptual  
12 infirmities.<sup>56</sup>

13 Thus, although the DCF model is a recognized approach to estimating the ROE, it is not  
14 without shortcomings and does not otherwise eliminate the need to ensure that the “end  
15 result” is fair. The Indiana Utility Regulatory has recognized this principle:

16 There are three principal reasons for our unwillingness to place a great deal  
17 of weight on the results of any DCF analysis. One is. . . the failure of the  
18 DCF model to conform to reality. The second is the undeniable fact that  
19 rarely if ever do two expert witnesses agree on the terms of a DCF equation  
20 for the same utility – for example, as we shall see in more detail below,  
21 projections of future dividend cash flow and anticipated price appreciation  
22 of the stock can vary widely. And, the third reason is that the unadjusted  
23 DCF result is almost always well below what any informed financial  
24 analysis would regard as defensible, and therefore requires an upward  
25 adjustment based largely on the expert witness’s judgment. In these  
26 circumstances, we find it difficult to regard the results of a DCF  
27 computation as any more than suggestive.<sup>57</sup>

28 FERC has also recognized the potential for any application of the DCF model to produce  
29 unreliable results.<sup>58</sup>

30 As this discussion indicates, considering the results of alternative approaches  
31 reduces the potential for error associated with any single quantitative method. Just as  
32 investors inform their decisions using a variety of methodologies, my evaluation of a fair  
33 ROE for the Company considered the results of multiple financial models.

---

<sup>56</sup> Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 429.

<sup>57</sup> *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17–18 (IURC 8/24/1990).

<sup>58</sup> *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

**Q59. DOES THE FACT THAT KENTUCKY POWER IS A SUBSIDIARY OF AEP ALTER THESE FUNDAMENTAL STANDARDS?**

A59. No. Although the Kentucky Power has no publicly traded common stock and AEP is the Company's only shareholder, this does not change the standards governing the determination of a just and reasonable ROE. Ultimately, the common equity that is 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 must compete with other investment opportunities, both external and internal. Unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, capital will be allocated elsewhere, the Company's financial integrity will be weakened, and investors will demand a higher rate of return. Kentucky Power's ability to offer a reasonable ROE is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

**Q60. WHAT DOES THIS DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE ROE FOR A UTILITY?**

A60. Although the ROE is cannot be observed directly, it is a function of the returns available from other investment 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 quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

1 **B. Discounted Cash Flow Analysis**

2 **Q61. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON**  
3 **EQUITY?**

4 A61. DCF models assume that the price of a share of common stock is equal to the present value  
5 of the expected cash flows (*i.e.*, future dividends and stock price) that will be received  
6 while holding the stock, discounted at investors' required rate of return. Rather than  
7 developing annual estimates of cash flows into perpetuity, the DCF model can be simplified  
8 to a "constant growth" form:<sup>59</sup>

9 
$$k_e = \frac{D_1}{P_0} + g$$

10 where:  $k_e$  = Cost of equity;  
11  $D_1$  = Expected dividend per share in the coming year;  
12  $P_0$  = Current price per share; and,  
13  $g$  = Investors' long-term growth expectations.

14 This constant growth form of the DCF model recognizes that the rate of return to  
15 stockholders consists of two parts: 1) dividend yield ( $D_1/P_0$ ); and 2) growth ( $g$ ). In other  
16 words, investors expect to receive a portion of their total return in the form of current  
17 dividends and the remainder through price appreciation.

18 **Q62. WHAT STEPS ARE REQUIRED TO APPLY THE CONSTANT GROWTH DCF**  
19 **MODEL?**

20 A62. The first step is to determine the expected dividend yield ( $D_1/P_0$ ) for the firm in question.  
21 This is usually calculated based on an estimate of dividends to be paid in the coming year  
22 divided by the current price of the stock. The second, and more controversial, step is to  
23 estimate investors' long-term growth expectations ( $g$ ) for the firm. The final step is to add

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<sup>59</sup> 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 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.

the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

**Q63. HOW DO YOU DETERMINE THE DIVIDEND YIELD?**

A63. I rely on Value Line's estimates of dividends to be paid by each utility in the proxy group 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 ranged from 2.4% to 6.1% and averaged 3.8%.

**Q64. WHAT IS THE NEXT STEP TO APPLY THE CONSTANT GROWTH DCF MODEL?**

A64. 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 implementing the DCF model is not a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "g" that matters in applying the DCF model is the forward-looking expectations of real-world investors.

**Q65. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?**

A65. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current 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 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 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.

**Q66. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS ALSO CONSIDER HISTORICAL TRENDS?**

A66. 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.

**Q67. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE UTILITY GROUP?**

A67. The earnings growth projections for each of the firms in the Utility Group reported by Value Line, IBES,<sup>60</sup> and Zacks are displayed on page 2 of Exhibit AMM-5.

**Q68. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS SOMETIMES ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?**

A68. 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

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<sup>60</sup> Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by LSEG.



1 on book equity. Furthermore, if the earned rate of return and the payout ratio are constant  
2 over time, growth in earnings and dividends will be equal to growth in book value. Even  
3 though these conditions are never met in practice, this “sustainable growth” approach may  
4 provide a rough guide for evaluating a firm’s growth prospects and is frequently proposed  
5 in regulatory proceedings.

6 The sustainable growth rate is calculated by the formula,  $g = br + sv$ , where “b” is  
7 the expected retention ratio, “r” is the expected earned return on equity, “s” is the percent  
8 of common equity expected to be issued annually as new common stock, and “v” is the  
9 equity accretion rate. Under DCF theory, the “sv” factor is a component of the growth rate  
10 designed to capture the impact of issuing new common stock at a price above, or below,  
11 book value. The sustainable, “br+sv” growth rates for each firm in the proxy group are  
12 summarized on page 2 of Exhibit AMM-5, with the underlying details being presented on  
13 Exhibit AMM-6.

14 The sustainable growth rate analysis shown in Exhibit AMM-6 incorporates an  
15 “adjustment factor” because Value Line’s reported returns are based on year-end book  
16 values. Since earnings are a flow over the year and book value is determined at a given  
17 point in time, the measurement of earnings and book value are distinct concepts. It is this  
18 fundamental difference between a flow (earnings) and point estimate (book value) that  
19 makes it necessary to adjust to mid-year in calculating the ROE. Given that book value  
20 will increase or decrease over the year, using year-end book value (as Value Line does)  
21 understates or overstates the average investment that corresponds to the flow of earnings.  
22 To address this concern, earnings must be matched with a corresponding representative  
23 measure of book value, or the resulting ROE will be distorted. The adjustment factor  
24 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.<sup>61</sup>

**Q69. ARE THERE SIGNIFICANT SHORTCOMINGS ASSOCIATED WITH THE “BR+SV” GROWTH RATE?**

A69. 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 estimating investor expectations, 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, such as share prices, as are analysts’ EPS growth forecasts.<sup>62</sup> 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.

**Q70. WHAT COST OF COMMON EQUITY ESTIMATES ARE IMPLIED FOR THE UTILITY GROUP USING THE DCF MODEL?**

A70. 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.

**Q71. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ILLOGICAL ESTIMATES?**

A71. 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.

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<sup>61</sup> 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).

<sup>62</sup> Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 307.

1 **Q72. HOW DO YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE**  
2 **RANGE?**

3 A72. I base my evaluation of DCF estimates at the low end of the range on the fundamental risk-  
4 return tradeoff, which holds that investors will only take on more risk if they expect to earn  
5 a higher rate of return to compensate them for the greater uncertainty. Because common  
6 stocks lack the protections associated with an investment in long-term bonds, a utility's  
7 common stock imposes far greater risks on investors. As a result, the rate of return that  
8 investors require from a utility's common stock is considerably higher than the yield  
9 offered by senior, long-term debt. Consistent with this principle, DCF results that are not  
10 sufficiently higher than the yield available on less risky utility bonds must be eliminated.

11 **Q73. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?**

12 A73. Yes. FERC has noted that adjustments are justified where applications of the DCF  
13 approach and other methods produce illogical results. FERC evaluates low-end DCF  
14 results against observable yields on long-term public utility debt and has recognized that it  
15 is appropriate to eliminate estimates that do not sufficiently exceed this threshold.<sup>63</sup>  
16 FERC's current practice is to exclude low-end cost of estimates that fall below the  
17 six-month average yield on Baa-rated utility bonds, plus 20% of the CAPM market risk  
18 premium.<sup>64</sup> In addition, FERC also excludes estimates that are "irrationally or  
19 anomalously high."<sup>65</sup>

20 **Q74. DO YOU EXCLUDE ANY ESTIMATES AT THE LOW OR HIGH END OF THE**  
21 **RANGE OF DCF RESULTS?**

22 A74. Yes. As highlighted on page 3 of Exhibit AMM-5, I remove eight low-end DCF cost of  
23 equity estimates ranging from 5.9% to 7.5%, as well as three other DCF cost of equity

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<sup>63</sup> See, *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,129 at PP 387, 388 (2019).

<sup>64</sup> Based on the six-month average yield at June 2025 of 6.06% and the 7.2% market risk premium shown on Exhibit AMM-7, this implies a current low-end threshold of approximately 7.5%.

<sup>65</sup> *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,154 at P 152 (2020).

estimates ranging from 16.1% to 20.4%. After removing these illogical values, the lower end of the DCF results for the Utility Group is set by a cost of equity estimate of 7.6%, and the upper end is established by a cost of equity estimate of 13.1%. Although a 13.1% cost of equity estimate may exceed the other values, low-end DCF estimates below 8.0% which were retained 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.

**Q75. WHAT ROE ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE UTILITY GROUP?**

A75. As shown on page 3 of Exhibit AMM-5 and summarized in Figure AMM-7, application of the constant growth DCF model results in the following ROE estimates:

**FIGURE AMM-7  
DCF RESULTS – UTILITY GROUP**

<u>Growth Rate</u>	<u>Average</u>	<u>Midpoint</u>
Value Line	9.7%	10.1%
IBES	10.6%	11.0%
Zacks	10.8%	11.4%
br + sv	9.1%	9.9%

**C. Capital Asset Pricing Model**

**Q76. PLEASE DESCRIBE THE CAPM.**

A76. 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 stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.0, 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,  
 $\beta_j$  = 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 ( $\beta$ ). Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, 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.

**Q77. WHY IS THE CAPM APPROACH RELEVANT WHEN EVALUATING THE COST OF EQUITY FOR KENTUCKY POWER?**

A77. The CAPM approach (which also forms the foundation of the ECAPM) generally is considered 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.

**Q78. HOW DO YOU APPLY THE CAPM TO ESTIMATE THE ROE?**

A78. 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. To capture the expectations of today's investors in current capital markets, the expected market rate of return was 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 10.3%. Combining this average growth rate with a year-ahead dividend yield of 1.7% results in a current cost of common equity estimate for the market as a whole ( $R_m$ ) of 12.0%. Subtracting a 4.8% risk-free rate based on the average yield on 30-year Treasury bonds for the six-months ending June 2025 produced a market equity risk premium of 7.2%.

**Q79. WHAT BETA VALUES DO YOU USE?**

A79. As indicated earlier in my discussion of risk measures for the proxy group, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

**Q80. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?**

A80. 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.<sup>66</sup>

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

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<sup>66</sup> Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at 99.

capitalization in determining the CAPM cost of equity.<sup>67</sup> Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Utility Group.

**Q81. WHAT IS THE BASIS FOR THE SIZE ADJUSTMENT?**

A81. The size adjustment required in applying the CAPM is based on the finding that, after controlling for risk differences as measured by 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. 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.”<sup>68</sup> As FERC has recognized, “[t]his type of size adjustment is a generally accepted approach to CAPM analyses.”<sup>69</sup>

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<sup>67</sup> 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*.

<sup>68</sup> Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 187.

<sup>69</sup> Opinion No. 531-B at P 117.

1 **Q82. IS THIS SIZE ADJUSTMENT RELATED TO THE RELATIVE SIZE OF**  
2 **KENTUCKY POWER AS COMPARED WITH THE PROXY GROUP?**

3 A82. No. I am not proposing to apply a general size risk premium in evaluating a just and  
4 reasonable ROE for the Company and my recommendation does not include any  
5 adjustment related to the relative size of Kentucky Power. Rather, this size adjustment is  
6 specific to the CAPM and merely corrects for an observed inability of the beta measure to  
7 fully reflect the risks perceived by investors for the firms in the proxy group.

8 **Q83. WHAT IS THE IMPLIED ROE FOR THE UTILITY GROUP USING THE CAPM**  
9 **APPROACH?**

10 A83. As shown on Exhibit AMM-7, the CAPM approach implies an average ROE for the Utility  
11 Group of 10.5%, or 11.0% after adjusting for the impact of firm size.

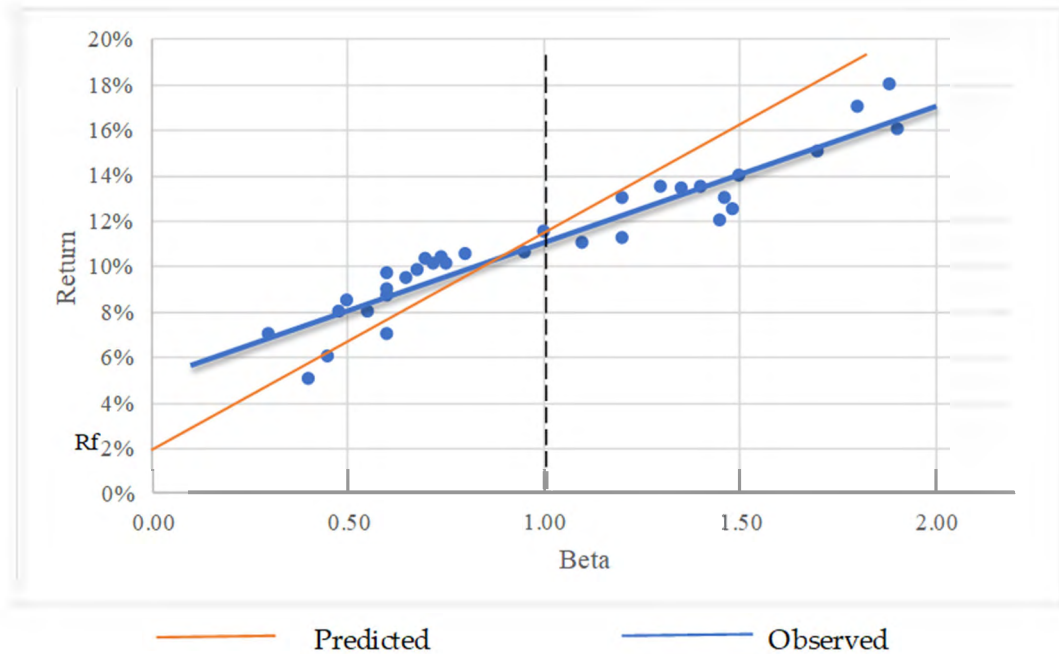
12 **D. Empirical Capital Asset Pricing Model**

13 **Q84. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL**  
14 **APPLICATIONS OF THE CAPM?**

15 A84. Empirical tests of the CAPM have shown that low-beta securities earn higher returns than  
16 the CAPM would predict, and high-beta securities earn less than predicted. In other words,  
17 the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with  
18 low-beta stocks tending to have higher returns and high-beta stocks tending to have lower  
19 risk returns than predicted by the CAPM. This is illustrated graphically in Figure  
20 AMM-8:



**FIGURE AMM-8**  
**CAPM – PREDICTED VS. OBSERVED RETURNS**



Because the betas of utility stocks, including those in the proxy 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.<sup>70</sup>

Based on a review of the empirical evidence, *New Regulatory Finance* concluded the expected return on a security is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

<sup>70</sup> Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 189.

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.

**Q85. WHAT COST OF EQUITY IS INDICATED BY THE ECAPM?**

A85. My application of the ECAPM is based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connection 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 10.9%, or 11.4% after adjusting for the effect of firm size.

**E. Electric Utility Risk Premium**

**Q86. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.**

A86. 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.

**Q87. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?**

A87. 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 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.

**Q88. HOW DO YOU IMPLEMENT THE RISK PREMIUM METHOD?**

A88. 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.

**Q89. HOW DO YOU CALCULATE EQUITY RISK PREMIUMS BASED ON ALLOWED RETURNS?**

A89. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by S&P Global Market Intelligence and published in its *RRA Regulatory Focus* report. 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 2024.<sup>71</sup> As shown there, over this period these equity risk

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<sup>71</sup> My analysis encompasses the entire period for which published data is available.

1 premiums for electric utilities average 3.90%, and the yields on public utility bonds average  
2 7.74%.

3 **Q90. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE**  
4 **CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?**

5 A90. Yes. Equity risk premiums are not constant and tend to move inversely with interest rates.  
6 In other words, when interest rate levels are relatively high, equity risk premiums narrow,  
7 and when interest rates are relatively low, equity risk premiums widen. The implication of  
8 this inverse relationship is that the cost of equity does not move as much as, or in lockstep  
9 with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of  
10 equity may only rise or fall some fraction of 1%. Therefore, when implementing the risk  
11 premium method, adjustments are required to incorporate this inverse relationship if the  
12 current interest rate is different from the average interest rate represented in the data set.

13 Current bond yields are lower than those prevailing over the risk premium study  
14 periods. Given that equity risk premiums move inversely with interest rates, these lower  
15 bond yields also imply an increase in the equity risk premium. In other words, higher  
16 required equity risk premiums offset the impact of declining interest rates on the ROE.

17 **Q91. IS THIS INVERSE RELATIONSHIP CONFIRMED BY PUBLISHED FINANCIAL**  
18 **RESEARCH?**

19 A91. Yes. The inverse relationship between equity risk premiums and interest rates has been  
20 widely reported in the financial literature. As summarized by *New Regulatory Finance*:

21 Published studies by Brigham, Shome, and Vinson (1985), Harris (1986),  
22 Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok  
23 (1983), Morin (2005), and McShane (2005), and others demonstrate that,  
24 beginning in 1980, risk premiums varied inversely with the level of interest  
25 rates – rising when rates fell and declining when rates rose.<sup>72</sup>

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<sup>72</sup> Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports (2006) at 128.

1 Other regulators have also recognized that, although the cost of equity trends in the same  
2 direction as interest rates, these variables do not move in lockstep.<sup>73</sup> This relationship is  
3 illustrated in the figure on page 3 of Exhibit AMM-9.

4 **Q92. WHAT ROE IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS**  
5 **OF ALLOWED RETURNS?**

6 A92. Based on the regression output between the interest rates and equity risk premiums  
7 displayed on page 3 of Exhibit AMM-9, the equity risk premium for electric utilities  
8 increases by approximately 42 basis points for each percentage point drop in the yield on  
9 average public utility bonds. As illustrated on page 1 of Exhibit AMM-9 with an average  
10 yield on public utility bonds for the six month period ending June 2025 of 5.89%, this  
11 implies a current equity risk premium of 4.68% for electric utilities. Adding this equity  
12 risk premium to the average yield on Baa utility bonds of 6.06% implies a current ROE of  
13 10.74%.

14 **F. Expected Earnings Approach**

15 **Q93. WHAT OTHER ANALYSIS DO YOU CONDUCT TO ESTIMATE THE ROE?**

16 A93. I also evaluate the ROE using the expected earnings method. Reference to rates of return  
17 available from alternative investments of comparable risk can provide an important  
18 benchmark in assessing the return necessary to assure confidence in the financial integrity  
19 of a firm and its ability to attract capital. This expected earnings approach is consistent  
20 with the economic underpinnings for a just and reasonable rate of return established by the  
21 U.S. Supreme Court in *Bluefield* and *Hope*.<sup>74</sup> Moreover, it avoids the complexities and  
22 limitations of capital market methods and instead focuses on the returns earned on book  
23 equity, which are readily available to investors.

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<sup>73</sup> See, e.g., California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-7, [https://cdn.entergy-mississippi.com/userfiles/content/price/tariffs/eml\\_frp.pdf](https://cdn.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf) (last visited May 25, 2025); *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

<sup>74</sup> See *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944).

**Q94. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?**

A94. The expected earnings approach is based on the concept 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.

**Q95. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?**

A95. 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. Although 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 returns on book value equity are analogous to the allowed ROE on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

**Q96. WHAT OTHER CONSIDERATION SUPPORTS REFERENCE TO EXPECTED RETURNS ON BOOK VALUE?**

A96. 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 regulators' 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

1 accounting records. This is analogous to the expected earnings approach, which measures  
2 the return that investors expect the utility to earn on book value. As a result, the expected  
3 earnings approach provides a meaningful guide to ensure that the allowed ROE is similar  
4 to what other utilities of comparable risk will earn on invested capital. This expected  
5 earnings test does not require theoretical models to indirectly infer investors' perceptions  
6 from stock prices or other market data. As long as the proxy companies are similar in risk,  
7 their expected earned returns on invested capital provide a direct benchmark for investors'  
8 opportunity costs that is independent of fluctuating stock prices, market-to-book ratios,  
9 debates over DCF growth rates, or the limitations inherent in any theoretical model of  
10 investor behavior.

11 **Q97. WHAT ROE IS INDICATED FOR KENTUCKY POWER BASED ON THE**  
12 **EXPECTED EARNINGS APPROACH?**

13 A97. For the firms in the Utility Group, the year-end returns on common equity projected by  
14 Value Line over its forecast horizon are shown on Exhibit AMM-10. As I explained earlier  
15 in my discussion of the  $br+sv$  growth rates used to apply the DCF model, Value Line's  
16 returns on common equity are calculated using year-end equity balances, which understates  
17 the average return earned over the year.<sup>75</sup> Accordingly, these year-end values were  
18 converted to average returns using the same adjustment factor discussed earlier and  
19 developed on Exhibit AMM-6. As shown on Exhibit AMM-10, Value Line's projections  
20 suggest an average ROE of 11.1% for the Utility Group.

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<sup>75</sup> 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.

**G.     Flotation Costs**

**Q98.   WHAT OTHER CONSIDERATION IS RELEVANT IN EVALUATING A FAIR ROE FOR A UTILITY?**

A98.   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. Although Kentucky Power has no publicly traded stock and does not incur flotation costs directly, equity capital is provided by investors through AEP’s sale of common shares. Thus, these expenses are also relevant when evaluating the fair and reasonable ROE for the Company’s jurisdictional utility operations.

**Q99.   IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO RECOGNIZE EQUITY ISSUANCE COSTS?**

A99.   No. Although debt flotation costs are amortized over the life of the bonds and increase the effective cost of debt capital, there is no similar accounting treatment to recognize equity flotation costs. As a result, equity flotation costs are not included in a utility’s rate base or 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.



1 **Q100. DOES ACADEMIC EVIDENCE SUPPORT A FLOTATION COST**  
2 **ADJUSTMENT?**

3 A100. Yes. The financial literature and evidence in this case provides a sound theoretical and  
4 practical basis to consider flotation costs in evaluating a fair ROE for Kentucky Power.  
5 Even when the utility is not contemplating any new sales of common stock, the need for a  
6 flotation cost adjustment to compensate for past equity issues has been recognized in the  
7 financial literature. A Public Utilities Fortnightly article, for example, demonstrated that  
8 even if no further stock issues are contemplated, a flotation cost adjustment in all future  
9 years is required to keep shareholders whole, and that the flotation cost adjustment must  
10 consider total equity, including retained earnings.<sup>76</sup> Similarly, *New Regulatory Finance*  
11 contains the following discussion:

12 Another controversy is whether the flotation cost allowance should still be  
13 applied when the utility is not contemplating an imminent common stock  
14 issue. Some argue that flotation costs are real and should be recognized in  
15 calculating the fair rate of return on equity, but only at the time when the  
16 expenses are incurred. In other words, the flotation cost allowance should  
17 not continue indefinitely, but should be made in the year in which the sale  
18 of securities occurs, with no need for continuing compensation in future  
19 years. This argument implies that the company has already been  
20 compensated for these costs and/or the initial contributed capital was  
21 obtained freely, devoid of any flotation costs, which is an unlikely  
22 assumption, and certainly not applicable to most utilities. The flotation cost  
23 adjustment cannot be strictly forward-looking unless all past flotation costs  
24 associated with past issues have been recovered.<sup>77</sup>

25 **Q101. CAN YOU ILLUSTRATE WHY INVESTORS WILL NOT HAVE THE**  
26 **OPPORTUNITY TO EARN THEIR REQUIRED ROE UNLESS FLOTATION**  
27 **COSTS ARE CONSIDERED?**

28 A101. Yes. Assume a utility sells \$10 worth of common stock at the beginning of year 1. If the  
29 utility incurs flotation costs of \$0.48 (5% of the net proceeds), then only \$9.52 is available

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<sup>76</sup> E. F. Brigham, D. A. Aberwald, and L. C. Gapenski, *Common Equity Flotation Costs and Rate Making*, Pub. Util. Fortnightly (May 2, 1985); see also Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 335.

<sup>77</sup> Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 335.

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 Figure AMM-9, if the allowed ROE 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 really only be 5.25%, instead of 5.5%:

**FIGURE AMM-9  
NO FLOTATION COST ADJUSTMENT**

<u>Year</u>	<u>Common Stock</u>	<u>Retained Earnings</u>	<u>Total Equity</u>	<u>Market Price</u>	<u>M/B Ratio</u>	<u>Allowed ROE</u>	<u>EPS</u>	<u>DPS</u>	<u>Payout Ratio</u>
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	<u>\$10.55</u>	<u>\$11.08</u>	1.050	10.50%	<u>\$ 1.11</u>	<u>\$ 0.55</u>	50.0%
<b>Growth</b>			<b>5.25%</b>	<b>5.25%</b>			<b>5.25%</b>	<b>5.25%</b>	

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 Figure AMM-10 below, by allowing an ROE of 10.75% (a 10.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 10.5% required ROE, since actual growth is now equal to 5.5%.

**FIGURE AMM-10**  
**INCLUDING FLOTATION COST ADJUSTMENT**

<u>Year</u>	<u>Common Stock</u>	<u>Retained Earnings</u>	<u>Total Equity</u>	<u>Market Price</u>	<u>M/B Ratio</u>	<u>Allowed ROE</u>	<u>EPS</u>	<u>DPS</u>	<u>Payout Ratio</u>
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%
<b>Growth</b>			<b>5.50%</b>	<b>5.50%</b>			<b>5.50%</b>	<b>5.50%</b>	

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 ROE. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

**Q102. ARE EQUITY FLOTATION COSTS PARTICULARLY RELEVANT IN THIS PROCEEDING?**

A102. 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. Kentucky Power's parent company anticipates new equity issuances totaling more than \$2.5 billion over the 2025 to 2029 period,<sup>78</sup> with Value Line projecting that AEP will issue over 17 million new shares of common stock over its forecast horizon.<sup>79</sup>

**Q103. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?**

A103. 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 company in Value Line's electric and gas utility industries. For all companies in the electric and gas

<sup>78</sup> American Electric Power Company, *March Investor Meetings* (Mar. 3-5, 2025) at 9, [https://docs.aep.com/docs/investors/eventspresentationsandwebcasts/Mar2025InvestorMtgs\\_Handout.pdf](https://docs.aep.com/docs/investors/eventspresentationsandwebcasts/Mar2025InvestorMtgs_Handout.pdf) (last visited July 16, 2025).

<sup>79</sup> The Value Line Investment Survey, *American Elec. Pwr.* (Mar. 7, 2025).

1 industries, flotation costs averaged approximately 2.5%. Applying the average 2.5%  
2 expense percentage to the Utility Group dividend yield of 3.8% produces a flotation cost  
3 adjustment on the order of 10 basis points. Although I did not make an explicit adjustment  
4 to the results of my quantitative methods to include an adjustment for flotation costs  
5 associated with issuing common stock, this is another legitimate consideration that  
6 supports the reasonableness of my evaluation of a just and reasonable ROE for Kentucky  
7 Power in this case.

## **VI. NON-UTILITY BENCHMARK**

### **Q104. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

8 A104. This section presents the results of my DCF analysis for a group of low-risk firms in the  
9 competitive sector, which I refer to as the “Non-Utility Group.” I do not rely on this  
10 analysis to arrive at my recommended ROE range of reasonableness; however, it is my  
11 opinion that this is a relevant consideration in evaluating a just and reasonable ROE for the  
12 Company’s electric utility operations.  
13

### **Q105. DO UTILITIES COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?**

14 A105. Yes. The cost of capital is an opportunity cost based on the returns that investors could  
15 realize by putting their money in other alternatives. The total capital invested in utility  
16 stocks is only a small fraction of total common stock investment, and there is an abundance  
17 of other alternatives available to investors. Utilities must compete for capital, not just  
18 against firms in their own industry, but with other investment opportunities of comparable  
19 risk. This understanding is consistent with modern portfolio theory, which is built on the  
20 assumption that rational investors will hold a diverse portfolio of stocks and not just  
21 companies in a single industry.  
22

1 **Q106. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER**  
2 **INVESTORS' REQUIRED ROE FOR NON-UTILITY COMPANIES?**

3 A106. Yes. The cost of equity capital in the competitive sector of the economy underpins utility  
4 ROEs because regulation purports to serve as a substitute for the actions of competitive  
5 markets. The U.S. Supreme Court has recognized that it is the degree of risk, not the nature  
6 of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield*  
7 case refers to “business undertakings which are attended by corresponding risks and  
8 uncertainties.”<sup>80</sup> It does not restrict consideration to other utilities. Similarly, the *Hope*  
9 case states:

10 By that standard the return to the equity owner should be commensurate  
11 with returns on investments in other enterprises having corresponding  
12 risks.<sup>81</sup>

13 As in the *Bluefield* decision, there is nothing to restrict “other enterprises” solely to the  
14 utility industry.

15 **Q107. WHAT CRITERIA DO YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?**

16 A107. My comparable risk proxy group was composed of those United States companies followed  
17 by Value Line that:

- 18 1) pay common dividends;  
19 2) have a Safety Rank of “1”;  
20 3) have a Financial Strength Rating of “B++” or greater;  
21 4) have a beta of 0.90 or less; and  
22 5) have investment grade credit ratings from Moody’s and S&P.

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<sup>80</sup> *Bluefield*, 262 U.S. at 692.

<sup>81</sup> *Hope*, 320 U.S. at 603.

**Q108. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP COMPARE WITH THE UTILITY GROUP?**

A108. Figure AMM-11 compares the Non-Utility Group with the Utility Group and Kentucky Power across the measures of investment risk discussed earlier:

**FIGURE AMM-11  
COMPARISON OF RISK INDICATORS**

	<u>Credit Ratings</u>		<u>Value Line</u>		
	<u>Moody's</u>	<u>S&amp;P</u>	<u>Safety Rank</u>	<u>Financial Strength</u>	<u>Beta</u>
Non-Utility Group	A2	A	1	A+	0.73
Utility Group	Baa2	BBB+	2	A	0.80
Kentucky Power	Baa3	BBB	1	A	0.70

Note: Kentucky Power's Value Line risk indicators are for its parent company, AEP.

As shown above, considered together the risk indicators for the Non-Utility Group generally suggest less risk than for the Utility Group and Kentucky Power.

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, McDonald's, 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%. 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.

**Q109. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?**

A109. I apply the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Utility Group. The results of my DCF analysis for the

Non-Utility Group are presented in Exhibit AMM-12. As summarized in Figure AMM-12, after eliminating illogical values, application of the constant growth DCF model results in the following cost of equity estimates:

**FIGURE AMM-12**  
**DCF RESULTS – NON-UTILITY GROUP**

<u>Growth Rate</u>	<u>Average</u>	<u>Midpoint</u>
Value Line	10.1%	11.4%
IBES	10.2%	11.5%
Zacks	10.5%	11.7%

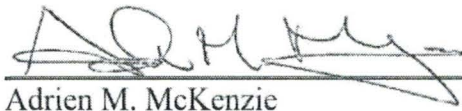
As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is 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 just and reasonable ROE for Kentucky Power.

**Q110. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A110. 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

COUNTY OF TARRANT )

STATE OF TEXAS )

Case No. 2025-00257

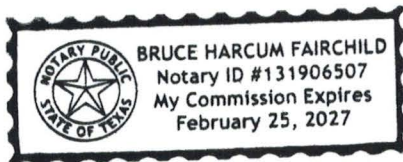
Subscribed and sworn to before me, a Notary Public in and before said County and State, by Adrien M. McKenzie, on AUGUST 14, 2025.



Notary Public

My Commission Expires 2/25/2027

Notary ID Number TX # 131906507





**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<sup>®</sup>) 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 more than 200 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, District of Columbia, Florida, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming. My testimony has 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 common 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.  
Financial Concepts and Applications  
*Economic and Financial Counsel*

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**Summary of Qualifications**

Adrien McKenzie has over 35 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before regulatory agencies, courts, 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. Mr. McKenzie holds the Chartered Financial Analyst (CFA®) designation and earned an MBA in finance from the University of Texas at Austin.

**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**

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*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 200 regulatory proceedings.
- In addition to filings before regulatory agencies in Alaska, Arkansas, Colorado, District of Columbia, Florida, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, 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.
- Evaluation of fair rate of return on equity for electric, gas, water, sewer, and telephone utilities, as well as natural gas pipelines.
- Analysis of capital structure issues for regulated utilities.
- Developing cost of service, cost allocation, and rate design studies.
- Design and development of explanatory models for nuclear plant capital costs in connection with prudence reviews.
- Analysis of avoided cost pricing for cogenerated power.
- Application of econometric models to analyze the impact of anti-competitive behavior, theft of trade secrets, and estimate lost profits.
- Valuation of closely-held businesses.

**ROE ANALYSIS****Exhibit AMM-2****Page 1 of 1****SUMMARY OF RESULTS**

<b>Method</b>	<b>Result</b>
<b>DCF</b>	
Value Line	9.7%
IBES	10.6%
Zacks	10.8%
Internal br + sv	9.1%
<b>CAPM</b>	10.5% -- 11.0%
<b>ECAPM</b>	10.9% -- 11.4%
<b>Utility Risk Premium</b>	10.7%
<b>Expected Earnings</b>	11.1%

**ROE Recommendation****Cost of Equity**

<b>Range</b>	<b>10.0% -- 11.0%</b>
<b>Recommendation</b>	<b>10.5%</b>

## REGULATORY MECHANISMS

Exhibit AMM-3

Page 1 of 6

UTILITY GROUP

	Company	Type of Cost Recovery Mechanism (a)									Other Regulatory Mechanisms (a)			
		Fuel/ Purch Power	Bad Debt	Pension	Environ- mental	Energy Efficiency/ Conservation	Other (b)	Gener- ation	Distri- bution	Trans- mission	Renew- ables	Decoupling/ Multi-Yr Plans/ Formula Rates	Earn Sharing/ Perf-Based Rates	Future Test Year
1	Alliant Energy	✓	✓	✓	--	✓	✓	--	--	✓	✓	✓	✓	✓
2	American Electric Power	✓	✓	--	✓	✓	✓	--	✓	✓	✓	--	✓	✓
3	Avista Corp.	✓	--	--	--	✓	✓	--	--	✓	✓	✓	--	--
4	Black Hills Corp.	✓	--	--	✓	✓	✓	--	--	✓	✓	--	--	--
5	CenterPoint Energy	✓	✓	✓	✓	✓	✓	--	✓	✓	✓	✓	✓	--
6	CMS Energy Corp.	✓	--	✓	--	✓	✓	--	--	--	--	--	✓	✓
7	Dominion Energy	✓	--	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
8	DTE Energy Co.	✓	--	--	--	✓	✓	--	--	--	✓	--	✓	✓
9	Duke Energy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
10	Edison International	✓	--	✓	✓	✓	✓	--	--	--	--	✓	--	✓
11	Entergy Corp.	✓	--	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
12	Eversource Energy	✓	✓	--	--	✓	✓	✓	✓	✓	--	--	--	--
13	Eversource Energy	✓	--	✓	✓	✓	✓	--	✓	✓	✓	✓	✓	--
14	FirstEnergy Corp.	✓	✓	--	✓	✓	✓	--	✓	✓	✓	✓	✓	✓
15	IDACORP, Inc.	✓	--	--	--	✓	✓	--	--	--	--	✓	✓	✓
16	NorthWestern Energy Grp.	✓	--	--	--	--	✓	✓	--	--	--	--	--	--
17	Otter Tail Corp.	✓	--	--	--	✓	✓	✓	--	✓	✓	✓	✓	✓
18	Pinnacle West Capital	✓	--	--	✓	✓	✓	✓	--	✓	✓	✓	--	--
19	Pub Sv Enterprise Grp.	D	✓	✓	✓	✓	✓	--	✓	✓	✓	✓	--	✓
20	Sempra Energy	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	✓	--	✓
Total		19	8	8	12	19	20	8	10	15	15	14	12	13

Source:

From 2024 SEC Form 10-K Reports and Investor Presentations (as provided on each company's website under Investor Relations). Data from S&P Global Market Intelligence, RRA State Regulatory Evaluations Quarterly Update (Dec. 2024) also used to supplement the Future Test Year findings.

See Exhibit AMM-3, pages 2-6.

D - Delivery-only utility.

UTILITY GROUP OPERATING COS.

Company	State	Type of Cost Recovery Mechanism (a)										Other Regulatory Mechanisms (a)		
		Fuel/ Purch	Bad Power Debt	Environ- Pension	Energy Conservation	Efficiency/ Conservation	Other (b)	Gener- ation	Distri- bution	Trans- mission	Renewables	Decoupling/ Multi-Yr Plans/ Formula Rates	Earn Sharing/ Perf-Based Rates	Future Test Year
<b>1 ALLIANT ENERGY CORP.</b>														
Interstate Power & Light Co.	IA	✓	--	✓	--	✓	✓	--	--	✓	--	✓	✓	✓
Wisconsin Power & Light Co.	WI	✓	✓	✓	--	✓	--	--	--	✓	--	--	✓	✓
<b>2 AMERICAN ELECTRIC POWER</b>														
Southwestern Electric Power Co.	AR	✓	--	--	✓	✓	✓	--	✓	✓	✓	✓	--	✓
Indiana Michigan Power Co.	IN	✓	--	--	✓	✓	--	--	✓	✓	✓	--	--	✓
Kentucky Power Co.	KY	✓	--	--	✓	✓	✓	--	--	--	--	--	--	--
Southwestern Electric Power Co.	LA	✓	--	--	--	✓	✓	--	✓	✓	✓	✓	--	--
Indiana Michigan Power Co.	MI	✓	--	--	--	✓	--	--	✓	✓	✓	--	--	✓
Ohio Power Co.	OH	D	✓	--	--	--	✓	--	✓	✓	✓	✓	--	✓
Public Service Co. of Oklahoma	OK	✓	--	--	--	✓	--	--	--	--	✓	--	--	--
Kingsport Power Co.	TN	✓	--	--	✓	--	✓	--	✓	✓	--	--	--	✓
AEP Texas Inc.	TX	D	--	--	--	✓	--	--	✓	✓	✓	✓	--	--
Southwestern Electric Power Co.	TX	✓	--	--	--	✓	--	--	✓	✓	--	--	--	--
Appalachian Power Co.	VA	✓	--	--	✓	✓	--	--	✓	✓	✓	--	--	--
Appalachian Pwr. Co./Wheeling Pwr.	WV	✓	--	--	✓	✓	✓	--	✓	✓	✓	--	--	--
<b>3 AVISTA CORP.</b>														
Alaska Electric Light & Power Co.	AK	✓	--	--	--	--	--	--	--	--	--	--	--	--
Avista Corp.	ID	✓	--	--	--	--	✓	--	--	--	--	✓	--	--
Avista Corp.	WA	✓	--	--	--	✓	✓	--	--	--	--	✓	--	--
<b>4 BLACK HILLS CORP.</b>														
Colorado Electric	CO	✓	--	--	--	✓	✓	--	--	✓	✓	--	--	--
South Dakota Electric	SD	✓	--	--	✓	--	--	--	--	✓	--	--	--	--
Wyoming Electric	WY	✓	--	--	--	✓	--	--	--	✓	--	--	--	--
<b>5 CENTERPOINT ENERGY</b>														
Southern Indiana Gas & Electric Co.	IN	✓	--	--	✓	✓	--	--	✓	✓	✓	✓	✓	--
CenterPoint Energy Houston Electric	TX	D	✓	✓	--	✓	✓	--	✓	✓	--	--	--	--
<b>6 CMS ENERGY</b>														
Consumers Energy Co.	MI	✓	--	✓	--	✓	✓	--	--	--	--	--	✓	✓
<b>7 DOMINION ENERGY</b>														
Virginia Electric & Power Co.	NC	✓	--	--	✓	✓	--	--	--	--	--	✓	✓	--
Dominion Energy South Carolina	SC	✓	--	✓	✓	✓	✓	✓	--	--	--	✓	--	--
Virginia Electric & Power Co.	VA	✓	--	--	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
<b>8 DTE ENERGY CO.</b>														
DTE Electric Co.	MI	✓	--	--	--	✓	✓	--	--	--	✓	--	✓	✓



UTILITY GROUP OPERATING COS.

Company	State	Type of Cost Recovery Mechanism (a)										Other Regulatory Mechanisms (a)		
		Fuel/ Purch	Bad Power Debt	Environ- Pension	Energy Conservation	Efficiency/ Conservation	Other (b)	Gener- ation	Distri- bution	Trans- mission	Renewables	Decoupling/ Multi-Yr Plans/ Formula Rates	Earn Sharing/ Perf-Based Rates	Future Test Year
<b>9 DUKE ENERGY</b>														
Duke Energy Florida LLC	FL	✓	--	--	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Duke Energy Indiana LLC	IN	✓	--	--	✓	✓	--	✓	✓	✓	✓	--	--	✓
Duke Energy Kentucky Inc.	KY	✓	--	--	✓	✓	--	--	--	--	--	--	--	✓
Duke Energy Carolinas LLC	NC	✓	--	--	--	✓	--	--	--	--	--	✓	✓	--
Duke Energy Progress LLC	NC	✓	--	--	--	✓	--	--	--	--	--	✓	✓	--
Duke Energy Ohio Inc.	OH	D	✓	--	--	✓	✓	--	✓	✓	--	✓	--	✓
Duke Energy Progress LLC	SC	✓	--	--	--	✓	--	--	--	--	--	✓	--	--
Duke Energy Carolinas LLC	SC	✓	--	--	--	✓	--	--	--	--	--	✓	--	--
<b>10 EDISON INTERNATIONAL</b>														
Southern California Edison Co.	CA	✓	--	✓	✓	✓	✓	--	--	--	--	✓	--	✓
<b>11 ENTERGY CORP.</b>														
Entergy Arkansas LLC	AR	✓	--	✓	--	✓	--	✓	--	✓	--	✓	--	✓
Entergy New Orleans LLC	LA	✓	--	✓	✓	✓	--	✓	✓	✓	--	✓	--	✓
Entergy Louisiana LLC	LA	✓	--	✓	✓	--	✓	✓	✓	✓	✓	✓	--	--
Entergy Mississippi LLC	MS	✓	--	✓	--	--	✓	✓	✓	✓	--	✓	✓	✓
Entergy Texas Inc.	TX	✓	--	✓	--	--	✓	✓	✓	✓	--	--	--	--
<b>12 EVERGY, INC.</b>														
Evergy Kansas Central Inc.	KS	✓	--	--	--	✓	✓	✓	✓	✓	--	--	--	--
Evergy Kansas South Inc.	KS	✓	--	--	--	✓	--	✓	✓	--	--	--	--	--
Evergy Metro Inc.	KS	✓	--	--	--	✓	✓	✓	✓	✓	--	--	--	--
Evergy Metro Inc.	MO	✓	--	--	--	✓	✓	--	--	✓	--	--	--	--
Evergy Missouri West Inc.	MO	✓	--	--	--	✓	✓	--	--	--	--	--	--	--
<b>13 EVERSOURCE ENERGY</b>														
Connecticut Light and Power Co.	CT	D	--	--	✓	✓	✓	--	✓	✓	✓	✓	--	--
NSTAR Electric Co.	MA	D	--	✓	--	✓	✓	--	✓	✓	✓	✓	✓	--
Public Service Co. of New Hampshire	NH	✓	--	--	✓	✓	✓	--	✓	✓	--	--	--	--
<b>14 FIRSTENERGY CORP.</b>														
Potomac Edison Co.	MD	D	--	--	--	✓	--	--	--	✓	--	--	--	--
Jersey Central Power & Light Co.	NJ	D	✓	--	✓	✓	--	--	✓	✓	--	✓	--	--
Cleveland Elec./Ohio Ed./Toledo Ed.	OH	D	✓	--	--	✓	✓	--	✓	✓	--	✓	✓	--
FE PA	PA	D	--	--	--	✓	✓	--	✓	--	--	--	--	✓
Monongahela Power Co.	WV	✓	--	--	--	--	✓	--	--	--	✓	--	--	--
Potomac Edison Co.	WV	✓	--	--	--	--	✓	--	--	--	✓	--	--	--
<b>15 IDACORP</b>														
Idaho Power Co.	ID	✓	--	--	--	✓	✓	--	--	--	--	✓	✓	--
Idaho Power Co.	OR	✓	--	--	--	✓	--	--	--	--	--	--	--	✓
<b>16 NORTHWESTERN ENERGY GRP.</b>														
NorthWestern Energy	MT	✓	--	--	--	--	✓	--	--	--	--	--	--	--
NorthWestern Energy	SD	✓	--	--	--	--	✓	✓	--	--	--	--	--	--

UTILITY GROUP OPERATING COS.

Company	State	Type of Cost Recovery Mechanism (a)										Other Regulatory Mechanisms (a)		
		Fuel/ Purch Power	Bad Debt	Pension	Environ- mental	Efficiency/ Conservation	Other (b)	Gener- ation	Distri- bution	Trans- mission	Renewables	Decoupling/ Multi-Yr Plans/ Formula Rates	Earn Sharing/ Perf-Based Rates	Future Test Year
17 OTTER TAIL CORP.														
Otter Tail Power Co.	MN	✓	--	--	--	✓	✓	✓	--	✓	✓	✓	--	✓
Otter Tail Power Co.	ND	✓	--	--	--	--	✓	✓	--	✓	✓	--	✓	✓
Otter Tail Power Corp.	SD	✓	--	--	--	✓	--	✓	--	✓	--	--	✓	--
18 PINNACLE WEST CAPITAL														
Arizona Public Service Co.	AZ	✓	--	--	✓	✓	✓	✓	--	✓	✓	✓	--	--
19 PUB SV ENTERPRISE GRP.														
Public Service Electric & Gas Co.	NJ	D	✓	✓	✓	✓	✓	--	✓	✓	✓	✓	--	✓
20 SEMPRA ENERGY														
San Diego Gas & Electric Co.	CA	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	✓	--	✓
Oncor Electric Delivery Co.	TX	D	--	--	--	--	--	--	✓	✓	--	--	--	--
Total	66	54	8	13	23	52	40	18	32	42	25	31	16	24

Notes

(a) From 2024 SEC Form 10-K Reports and Investor Presentations (as provided on each company's website under Investor Relations).

Data from S&P Global Market Intelligence, *RRA State Regulatory Evaluations Quarterly Update* (Dec. 2024) also used to supplement the Future Test Year findings.

(b) See , page 5.

D - Delivery-only utility.

**NOTE (b) - OTHER RECOVERY MECHANISMS**

	Company	State	Description
1	<b>ALLIANT ENERGY CORP.</b> Interstate Power & Light Co.	IA	Tax benefit rider
2	<b>AMERICAN ELECTRIC POWER</b> Southwestern Electric Power Co. Kentucky Power Co. Southwestern Electric Power Co. Ohio Power Co. Kingsport Power Co. Appalachian Pwr. Co./Wheeling Pwr. Co	AR KY LA OH TN WV	Vegetation management Decommissioning rider Vegetation management Vegetation management Vegetation management Vegetation management
3	<b>AVISTA CORP.</b> Avista Corp. Avista Corp.	ID WA	Wildfire resiliency, insurance Wildfire resiliency, insurance
4	<b>BLACK HILLS CORP.</b> Colorado Electric	CO	EV program, energy assistance benefit charge
5	<b>CENTERPOINT ENERGY</b> CenterPoint Energy Houston Electric LLC	TX	Temporary emergency electric energy facilities, system restoration cost
6	<b>CMS ENERGY</b> Consumers Energy Co.	MI	Decommissioning cost
7	<b>DOMINION ENERGY</b> Dominion Energy South Carolina Virginia Electric & Power Co.	SC VA	Relicensing/decommissioning Coastal Virginia Offshore Wind project, relicensing/decommissioning
8	<b>DTE ENERGY CO.</b> DTE Electric Co.	MI	Decommissioning cost
9	<b>DUKE ENERGY</b> Duke Energy Florida LLC Duke Energy Ohio Inc.	FL OH	Storm damage Storm damage
10	<b>EDISON INTERNATIONAL</b> Southern California Edison Co.	CA	Inflationary price increases, nuclear decommissioning, wildfire related costs, public purpose programs, wildfire liability insurance
11	<b>ENTERGY CORP.</b> Entergy Louisiana LLC Entergy Mississippi LLC Entergy Texas Inc.	LA MS TX	Resilience plan, tax adjustment mechanism Storm damage, ad valorem tax, vegetation Rate case expenses, advanced metering system
12	<b>EVERGY, INC.</b> Eversource Kansas Central Inc. Eversource Metro Inc. Eversource Metro Inc. Eversource Missouri West Inc.	KS KS MO MO	Ad valorem tax Ad valorem tax Ad valorem tax Ad valorem tax
13	<b>EVERSOURCE ENERGY</b> Connecticut Light and Power Co. NSTAR Electric Co. Public Service Co. of New Hampshire	CT MA NH	System benefits Low income customer discounts, vegetation management, storm restoration, advanced metering infrastructure, EV infrastructure System benefits, vegetation management, ad valorem tax, storm costs, pole plant adjustment mechanism
14	<b>FIRSTENERGY CORP.</b> Cleveland Elec./Ohio Ed./Toledo Ed. FE PA Monongahela Power Co. Potomac Edison Co.	OH PA WV WV	Smart meters Storm costs, Tax Act, smart meters, vegetation, management Vegetation management, storm costs Vegetation management, storm costs

**NOTE (b) - OTHER RECOVERY MECHANISMS**

	Company	State	Description
<b>15</b>	<b>IDACORP</b>		
	Idaho Power Co.	ID	Accumulated Deferred ITC annual utilization
<b>16</b>	<b>NORTHWESTERN ENERGY GRP.</b>		
	NorthWestern Energy	MT	Ad valorem tax
	NorthWestern Energy	SD	Ad valorem tax
<b>17</b>	<b>OTTER TAIL CORP.</b>		
	Otter Tail Power Co.	MN	Advanced metering initiative
	Otter Tail Power Co.	ND	Advanced metering initiative
<b>18</b>	<b>PINNACLE WEST CAPITAL</b>		
	Arizona Public Service Co.	AZ	Tax expense adjustor, Four Corners Court Resolution Surcharge (federally mandated emissions controls)
<b>19</b>	<b>PUB SV ENTERPRISE GRP.</b>		
	Public Service Electric & Gas Co.	NJ	Storm costs, electric vehicle program
<b>20</b>	<b>SEMPRA ENERGY</b>		
	San Diego Gas & Electric Co.	CA	Insurance premiums, wildfire mitigation, advanced metering initiative

**ELECTRIC GROUP OPERATING COS.**

	<b>Operating Company</b>	<b>Debt</b>	<b>Preferred</b>	<b>Common Equity</b>
<b>1</b>	<b>ALLIANT ENERGY CORP.</b>			
	Interstate Power & Light	47.8%	0.0%	52.2%
	Wisconsin Power & Light	45.1%	0.0%	54.9%
<b>2</b>	<b>AMERICAN ELEC PWR</b>			
	AEP Texas, Inc.	56.9%	0.0%	43.1%
	Appalachian Power Co.	49.6%	0.0%	50.4%
	Indiana Michigan Power Co.	50.7%	0.0%	49.3%
	Kentucky Power Co.	55.1%	0.0%	44.9%
	Kingsport Power Co.	47.0%	0.0%	53.0%
	Ohio Power Co.	48.9%	0.0%	51.1%
	Public Service Co. of Oklahoma	51.5%	0.0%	48.5%
	Southwestern Electric Pwr Co.	50.5%	0.0%	49.5%
	Wheeling Power Co.	55.3%	0.0%	44.7%
<b>3</b>	<b>AVISTA CORP.</b>			
	Avista Corp.	50.0%	0.0%	50.0%
	Alaska Electric Light & Power	37.0%	0.0%	63.0%
<b>4</b>	<b>BLACK HILLS CORP.</b>			
	Black Hills Power (South Dakota Elec.)	47.2%	0.0%	52.8%
	Cheyenne Light Fuel & Power (Wyo Elec.)	53.8%	0.0%	46.2%
	Black Hills/Colorado Electric Utility Co	50.0%	0.0%	50.0%
<b>5</b>	<b>CENTERPOINT ENERGY</b>			
	Centerpoint Energy Houston Electric	53.8%	0.0%	46.2%
<b>6</b>	<b>CMS ENERGY</b>			
	Consumers Energy Co.	51.6%	0.2%	48.3%
<b>7</b>	<b>DOMINION ENERGY</b>			
	Virginia Electric & Power	45.0%	0.0%	55.0%
	Dominion Energy South Carolina	46.9%	0.0%	53.1%
<b>8</b>	<b>DTE ENERGY CO.</b>			
	DTE Electric Co.	50.9%	0.0%	49.1%
<b>9</b>	<b>DUKE ENERGY</b>			
	Duke Energy Carolinas	49.5%	0.0%	50.5%
	Duke Energy Florida	48.5%	0.0%	51.5%
	Duke Energy Indiana	46.5%	0.0%	53.5%
	Duke Energy Ohio	43.3%	0.0%	56.7%
	Duke Energy Progress	51.1%	0.0%	48.9%
	Duke Energy Kentucky	45.7%	0.0%	54.3%
<b>10</b>	<b>EDISON INTERNATIONAL</b>			
	Southern California Edison Co.	58.4%	4.2%	37.4%

**ELECTRIC GROUP OPERATING COS.**

	<b>Operating Company</b>	<b>Debt</b>	<b>Preferred</b>	<b>Common Equity</b>
<b>11</b>	<b>ENTERGY CORP.</b>			
	Entergy Arkansas Inc.	53.4%	0.0%	46.6%
	Entergy Louisiana LLC	46.0%	0.0%	54.0%
	Entergy Mississippi Inc.	50.2%	0.0%	49.8%
	Entergy New Orleans Inc.	51.3%	0.0%	48.7%
	Entergy Texas Inc.	51.5%	0.6%	47.9%
<b>12</b>	<b>EVERGY, INC.</b>			
	Evergy Metro	48.8%	0.0%	51.2%
	Evergy Kansas Central	46.4%	0.0%	53.6%
<b>13</b>	<b>EVERSOURCE ENERGY</b>			
	Connecticut Light & Power	43.3%	1.0%	55.7%
	NSTAR Electric Co.	42.3%	0.4%	57.4%
	Public Service Co. of New Hampshire	43.2%	0.0%	56.8%
<b>14</b>	<b>FIRSTENERGY CORP.</b>			
	Cleve. Elec. Illum./Ohio Ed./Toledo Ed.	38.7%	0.0%	61.3%
	Jersey Central Power & Light Co.	32.0%	0.0%	68.0%
	Monongahela Power Co.	46.4%	0.0%	53.6%
	The Potomac Edison Co.	48.3%	0.0%	51.7%
	FE PA	47.3%	0.0%	52.7%
<b>15</b>	<b>IDACORP</b>			
	Idaho Power Co.	49.9%	0.0%	50.1%
<b>16</b>	<b>NORTHWESTERN ENERGY GROUP</b>			
	NorthWestern Corp.	50.3%	0.0%	49.7%
	NorthWestern Energy Public Svc Corp.	48.3%	0.0%	51.7%
<b>17</b>	<b>OTTER TAIL CORP.</b>			
	Otter Tail Power Co.	45.0%	0.0%	55.0%
<b>18</b>	<b>PINNACLE WEST CAPITAL</b>			
	Arizona Public Service Co.	47.2%	0.0%	52.8%
<b>19</b>	<b>PUB SV ENTERPRISE GRP</b>			
	Pub Service Electric & Gas Co.	44.8%	0.0%	55.2%
<b>20</b>	<b>SEMPRA ENERGY</b>			
	San Diego Gas & Electric	48.8%	0.0%	51.2%
	Oncor Electric Delivery	47.7%	0.0%	52.3%
	<b>Minimum (b)</b>	<b>32.0%</b>	<b>0.0%</b>	<b>37.4%</b>
	<b>Maximum (b)</b>	<b>58.4%</b>	<b>4.2%</b>	<b>68.0%</b>
	<b>Average (b)</b>	<b>48.2%</b>	<b>0.1%</b>	<b>51.7%</b>

Source:

Data from most recent SEC Form 10-K Reports and FERC Form 1 Reports.

**UTILITY GROUP**

	<b>Company</b>	<b>At Year-end 2024 (a)</b>			<b>Value Line Projected (b)</b>		
		<b>Debt</b>	<b>Preferred</b>	<b>Common Equity</b>	<b>Debt</b>	<b>Preferred</b>	<b>Common Equity</b>
1	Alliant Energy	58.4%	0.0%	41.6%	52.0%	52.0%	48.0%
2	American Elec Pwr	61.2%	0.0%	38.8%	57.5%	57.5%	42.5%
3	Avista Corp.	50.7%	0.0%	49.3%	46.5%	46.5%	53.5%
4	Black Hills Corp.	54.2%	0.0%	45.8%	55.5%	55.5%	44.5%
5	CenterPoint Energy	65.7%	0.0%	34.3%	59.0%	59.0%	41.0%
6	CMS Energy Corp.	65.4%	0.9%	33.8%	61.5%	61.5%	37.5%
7	Dominion Energy	56.5%	1.4%	42.1%	60.0%	60.0%	39.0%
8	DTE Energy Co.	65.3%	0.0%	34.7%	61.0%	61.0%	39.0%
9	Duke Energy Corp.	61.2%	0.7%	38.1%	61.0%	61.0%	38.0%
10	Edison International	66.7%	3.1%	30.2%	65.0%	65.0%	29.0%
11	Entergy Corp.	64.5%	0.5%	35.0%	63.5%	63.5%	36.5%
12	Evergy Inc.	55.5%	0.0%	44.5%	53.5%	53.5%	46.5%
13	Eversource Energy	64.1%	0.0%	35.9%	62.0%	62.0%	37.5%
14	FirstEnergy Corp.	63.1%	0.0%	36.9%	65.0%	65.0%	35.0%
15	IDACORP, Inc.	47.9%	0.0%	52.1%	43.0%	43.0%	57.0%
16	NorthWestern Energy Grp.	51.2%	0.0%	48.8%	50.5%	50.5%	49.5%
17	Otter Tail Corp.	36.1%	0.0%	63.9%	42.5%	42.5%	57.5%
18	Pinnacle West Capital	56.4%	0.0%	43.6%	55.0%	55.0%	45.0%
19	Pub Sv Enterprise Grp.	56.7%	0.0%	43.3%	56.0%	56.0%	44.0%
20	Sempra	47.2%	1.3%	51.5%	54.0%	54.0%	45.0%
<b>Minimum</b>		<b>36.1%</b>	<b>0.0%</b>	<b>30.2%</b>	<b>42.5%</b>	<b>42.5%</b>	<b>29.0%</b>
<b>Maximum</b>		<b>66.7%</b>	<b>3.1%</b>	<b>63.9%</b>	<b>65.0%</b>	<b>65.0%</b>	<b>57.5%</b>
<b>Average</b>		<b>57.4%</b>	<b>0.4%</b>	<b>42.2%</b>	<b>56.2%</b>	<b>56.2%</b>	<b>43.3%</b>

(a) SEC Form 10-K reports.

(b) The Value Line Investment Survey (Mar. 7, Apr. 18, and May 9, 2025).

**DIVIDEND YIELD**

		(a)	(b)	
	<b>Company</b>	<b>Price</b>	<b>Dividends</b>	<b>Yield</b>
1	Alliant Energy	\$ 60.93	\$ 2.03	3.3%
2	American Elec Pwr	\$ 105.10	\$ 3.80	3.6%
3	Avista Corp.	\$ 40.55	\$ 1.96	4.8%
4	Black Hills Corp.	\$ 59.55	\$ 2.70	4.5%
5	CenterPoint Energy	\$ 37.44	\$ 0.88	2.4%
6	CMS Energy Corp.	\$ 72.20	\$ 2.17	3.0%
7	Dominion Energy	\$ 53.76	\$ 2.67	5.0%
8	DTE Energy Co.	\$ 134.32	\$ 4.36	3.2%
9	Duke Energy Corp.	\$ 119.24	\$ 4.24	3.6%
10	Edison International	\$ 56.36	\$ 3.41	6.1%
11	Entergy Corp.	\$ 82.64	\$ 2.40	2.9%
12	Evergy Inc.	\$ 67.23	\$ 2.71	4.0%
13	Eversource Energy	\$ 59.23	\$ 3.05	5.1%
14	FirstEnergy Corp.	\$ 41.82	\$ 1.80	4.3%
15	IDACORP, Inc.	\$ 116.03	\$ 3.44	3.0%
16	NorthWestern Energy Grp.	\$ 57.10	\$ 2.65	4.6%
17	Otter Tail Corp.	\$ 78.32	\$ 2.10	2.7%
18	Pinnacle West Capital	\$ 92.59	\$ 3.61	3.9%
19	Pub Sv Enterprise Grp.	\$ 80.29	\$ 2.56	3.2%
20	Sempra	\$ 72.96	\$ 2.58	3.5%
	<b>Average</b>			<b>3.8%</b>

(a) Average of closing prices for 30 trading days ended May 19, 2025.

(b) The Value Line Investment Survey, Summary & Index (May 23, 2025).



**GROWTH RATES**

		(a)	(b)	(c)	(d)
		<b>Earnings Growth</b>			<b>br+sv</b>
	<b>Company</b>	<b>V Line</b>	<b>IBES</b>	<b>Zacks</b>	<b>Growth</b>
1	Alliant Energy	6.0%	6.5%	6.7%	5.8%
2	American Elec Pwr	6.5%	6.4%	6.4%	6.1%
3	Avista Corp.	5.5%	6.9%	6.1%	2.7%
4	Black Hills Corp.	3.5%	5.3%	5.3%	4.2%
5	CenterPoint Energy	6.5%	8.0%	7.8%	4.8%
6	CMS Energy Corp.	6.0%	7.7%	7.8%	6.0%
7	Dominion Energy	6.0%	15.4%	13.6%	4.9%
8	DTE Energy Co.	4.5%	7.9%	7.6%	6.9%
9	Duke Energy Corp.	6.0%	6.6%	6.3%	4.1%
10	Edison International	6.5%	10.0%	7.0%	6.2%
11	Entergy Corp.	3.0%	9.6%	9.5%	3.9%
12	Eversource Energy	7.5%	6.0%	5.7%	3.7%
13	Eversource Energy	5.5%	5.3%	5.7%	4.9%
14	FirstEnergy Corp.	4.5%	5.9%	6.4%	5.3%
15	IDACORP, Inc.	6.0%	7.4%	8.1%	4.6%
16	NorthWestern Energy Grp.	4.5%	6.5%	6.9%	3.0%
17	Otter Tail Corp.	4.5%	n/a	n/a	4.4%
18	Pinnacle West Capital	5.0%	2.2%	2.1%	4.1%
19	Pub Sv Enterprise Grp.	7.0%	8.6%	6.8%	5.2%
20	Sempra	5.5%	6.0%	7.9%	5.6%

(a) The Value Line Investment Survey (Mar. 7, Apr. 18, and May 9, 2025).

(b) IBES growth rates from LSEG, as provided by [www.fidelity.com](http://www.fidelity.com) (retrieved May 20, 2025).

(c) [www.zacks.com](http://www.zacks.com) (retrieved May 20, 2025).

(d) See Exhibit AMM-6.

COST OF EQUITY ESTIMATES

	(a)	(a)	(a)	(a)
	V Line	IBES	Zacks	br+sv Growth
1 Alliant Energy	9.3%	9.8%	10.1%	9.2%
2 American Elec Pwr	10.1%	10.0%	10.0%	9.7%
3 Avista Corp.	10.3%	11.7%	10.9%	7.5%
4 Black Hills Corp.	8.0%	9.8%	9.8%	8.8%
5 CenterPoint Energy	8.9%	10.4%	10.1%	7.1%
6 CMS Energy Corp.	9.0%	10.7%	10.8%	9.0%
7 Dominion Energy	11.0%	20.4%	18.6%	9.9%
8 DTE Energy Co.	7.7%	11.1%	10.9%	10.2%
9 Duke Energy Corp.	9.6%	10.2%	9.9%	7.6%
10 Edison International	12.6%	16.1%	13.1%	12.3%
11 Entergy Corp.	5.9%	12.5%	12.4%	6.8%
12 Evergy Inc.	11.5%	10.0%	9.7%	7.8%
13 Eversource Energy	10.6%	10.4%	10.8%	10.1%
14 FirstEnergy Corp.	8.8%	10.2%	10.7%	9.6%
15 IDACORP, Inc.	9.0%	10.4%	11.1%	7.6%
16 NorthWestern Energy Grp.	9.1%	11.1%	11.5%	7.7%
17 Otter Tail Corp.	7.2%	n/a	n/a	7.1%
18 Pinnacle West Capital	8.9%	6.1%	6.0%	8.0%
19 Pub Sv Enterprise Grp.	10.2%	11.8%	10.0%	8.4%
20 Sempra	9.0%	9.5%	11.5%	9.1%
<b>Average (b)</b>	<b>9.7%</b>	<b>10.6%</b>	<b>10.8%</b>	<b>9.1%</b>

(a) Sum of dividend yield (Exhibit AMM-5, p. 1) and respective growth rate (Exhibit AMM-5, p. 2).

(b) Excludes highlighted values.

## BR+SV GROWTH RATE

Exhibit AMM-6

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UTILITY GROUP

		(a)	(a)	(a)	(b)	(c)	(d)	(e)		(f)	(g)		
		2029			Adjustment				"sv" Factor				
	<u>Company</u>	<u>EPS</u>	<u>DPS</u>	<u>BVPS</u>	<u>b</u>	<u>r</u>	<u>Factor</u>	<u>Adjusted r</u>	<u>br</u>	<u>s</u>	<u>v</u>	<u>sv</u>	<u>br + sv</u>
1	Alliant Energy	\$4.25	\$2.43	\$31.90	42.8%	13.3%	1.0156	13.5%	5.8%	0.0005	0.5600	0.03%	5.8%
2	American Elec Pwr	\$7.50	\$4.31	\$60.90	42.5%	12.3%	1.0119	12.5%	5.3%	0.0140	0.5489	0.77%	6.1%
3	Avista Corp.	\$2.95	\$2.20	\$35.75	25.4%	8.3%	1.0162	8.4%	2.1%	0.0178	0.3190	0.57%	2.7%
4	Black Hills Corp.	\$5.00	\$3.10	\$56.00	38.0%	8.9%	1.0267	9.2%	3.5%	0.0273	0.2774	0.76%	4.2%
5	CenterPoint Energy	\$2.00	\$1.01	\$21.50	49.5%	9.3%	1.0263	9.5%	4.7%	0.0007	0.4267	0.03%	4.8%
6	CMS Energy Corp.	\$4.20	\$2.50	\$30.75	40.5%	13.7%	1.0146	13.9%	5.6%	0.0057	0.6273	0.36%	6.0%
7	Dominion Energy	\$4.25	\$2.67	\$37.25	37.2%	11.4%	1.0229	11.7%	4.3%	0.0122	0.4679	0.57%	4.9%
8	DTE Energy Co.	\$9.60	\$5.15	\$63.10	46.4%	15.2%	1.0114	15.4%	7.1%	(0.0031)	0.6342	-0.20%	6.9%
9	Duke Energy Corp.	\$8.00	\$5.00	\$76.50	37.5%	10.5%	1.0187	10.7%	4.0%	0.0018	0.4333	0.08%	4.1%
10	Edison International	\$7.00	\$4.25	\$50.00	39.3%	14.0%	1.0365	14.5%	5.7%	0.0105	0.5000	0.53%	6.2%
11	Entergy Corp.	\$4.20	\$3.00	\$43.45	28.6%	9.7%	1.0302	10.0%	2.8%	0.0246	0.4394	1.08%	3.9%
12	Evergy Inc.	\$5.00	\$3.25	\$47.50	35.0%	10.5%	1.0124	10.7%	3.7%	0.0004	0.4571	0.02%	3.7%
13	Eversource Energy	\$5.90	\$3.70	\$52.00	37.3%	11.3%	1.0267	11.6%	4.3%	0.0132	0.4526	0.60%	4.9%
14	FirstEnergy Corp.	\$3.30	\$2.10	\$26.75	36.4%	12.3%	1.0242	12.6%	4.6%	0.0130	0.5136	0.67%	5.3%
15	IDACORP, Inc.	\$7.10	\$4.20	\$74.00	40.8%	9.6%	1.0222	9.8%	4.0%	0.0136	0.4519	0.61%	4.6%
16	NorthWestern Energy Grp.	\$4.30	\$2.80	\$53.55	34.9%	8.0%	1.0186	8.2%	2.9%	0.0104	0.1762	0.18%	3.0%
17	Otter Tail Corp.	\$4.20	\$2.36	\$44.25	43.8%	9.5%	1.0081	9.6%	4.2%	0.0052	0.3897	0.20%	4.4%
18	Pinnacle West Capital	\$6.25	\$3.85	\$70.00	38.4%	8.9%	1.0262	9.2%	3.5%	0.0156	0.3778	0.59%	4.1%
19	Pub Sv Enterprise Grp.	\$5.25	\$3.24	\$42.25	38.3%	12.4%	1.0282	12.8%	4.9%	0.0063	0.5553	0.35%	5.2%
20	Sempra	\$6.30	\$3.28	\$59.50	47.9%	10.6%	1.0343	11.0%	5.2%	0.0077	0.4333	0.33%	5.6%

**BR+SV GROWTH RATE**
**Exhibit AMM-6**
**Page 2 of 2**
**UTILITY GROUP**

		(a)	(a)	(h)	(a)	(a)	(h)	(i)	(a)	(a)		(j)	(a)	(a)	(i)
		2029			2029			Chg	2029				Common Shares		
	<u>Company</u>	<u>Eq Ratio</u>	<u>Tot Cap</u>	<u>Com Eq</u>	<u>Eq Ratio</u>	<u>Tot Cap</u>	<u>Com Eq</u>	<u>Equity</u>	<u>High</u>	<u>Low</u>	<u>Avg.</u>	<u>M/B</u>	<u>2024</u>	<u>2029</u>	<u>Growth</u>
1	Alliant Energy	44.7%	\$15,681	\$7,009	48.0%	\$17,070	\$8,194	3.2%	\$80.0	\$65.0	\$72.5	2.273	256.69	257.00	0.02%
2	American Elec Pwr	42.4%	\$67,528	\$28,632	42.5%	\$75,900	\$32,258	2.4%	\$150.0	\$120.0	\$135.0	2.217	532.90	550.00	0.63%
3	Avista Corp.	49.0%	\$5,292	\$2,593	53.5%	\$5,700	\$3,050	3.3%	\$65.0	\$40.0	\$52.5	1.469	80.04	85.00	1.21%
4	Black Hills Corp.	43.5%	\$7,752	\$3,372	44.5%	\$9,900	\$4,406	5.5%	\$90.0	\$65.0	\$77.5	1.384	69.84	77.00	1.97%
5	CenterPoint Energy	34.5%	\$31,063	\$10,717	41.0%	\$34,000	\$13,940	5.4%	\$45.0	\$30.0	\$37.5	1.744	651.73	653.00	0.04%
6	CMS Energy Corp.	34.0%	\$23,536	\$8,002	37.5%	\$24,700	\$9,263	3.0%	\$95.0	\$70.0	\$82.5	2.683	298.80	302.00	0.21%
7	Dominion Energy	40.5%	\$64,778	\$26,235	39.0%	\$84,600	\$32,994	4.7%	\$80.0	\$60.0	\$70.0	1.879	852.00	880.00	0.65%
8	DTE Energy Co.	38.2%	\$29,328	\$11,203	39.0%	\$32,200	\$12,558	2.3%	\$200.0	\$145.0	\$172.5	2.734	207.17	206.00	-0.11%
9	Duke Energy Corp.	38.9%	\$126,467	\$49,196	38.0%	\$156,100	\$59,318	3.8%	\$155.0	\$115.0	\$135.0	1.765	776.00	780.00	0.10%
10	Edison International	27.1%	\$51,274	\$13,895	29.0%	\$69,000	\$20,010	7.6%	\$120.0	\$80.0	\$100.0	2.000	384.78	395.00	0.53%
11	Entergy Corp.	36.0%	\$41,917	\$15,090	36.5%	\$55,915	\$20,409	6.2%	\$85.0	\$70.0	\$77.5	1.784	429.58	460.00	1.38%
12	Evergy Inc.	48.0%	\$20,019	\$9,609	46.5%	\$23,400	\$10,881	2.5%	\$100.0	\$75.0	\$87.5	1.842	229.73	230.00	0.02%
13	Eversource Energy	36.5%	\$41,221	\$15,046	37.5%	\$52,400	\$19,650	5.5%	\$110.0	\$80.0	\$95.0	1.827	366.61	380.00	0.72%
14	FirstEnergy Corp.	35.6%	\$34,951	\$12,443	35.0%	\$45,300	\$15,855	5.0%	\$65.0	\$45.0	\$55.0	2.056	576.61	595.00	0.63%
15	IDACORP, Inc.	52.2%	\$6,385	\$3,333	57.0%	\$7,300	\$4,161	4.5%	\$150.0	\$120.0	\$135.0	1.824	53.96	56.00	0.74%
16	NorthWestern Energy Grp.	51.4%	\$5,555	\$2,855	49.5%	\$6,950	\$3,440	3.8%	\$75.0	\$55.0	\$65.0	1.214	61.32	64.00	0.86%
17	Otter Tail Corp.	58.5%	\$2,288	\$1,338	57.5%	\$2,525	\$1,452	1.6%	\$85.0	\$60.0	\$72.5	1.638	41.83	42.50	0.32%
18	Pinnacle West Capital	45.6%	\$14,813	\$6,755	45.0%	\$19,500	\$8,775	5.4%	\$130.0	\$95.0	\$112.5	1.607	119.10	125.00	0.97%
19	Pub Sv Enterprise Grp.	45.9%	\$35,078	\$16,101	44.0%	\$48,500	\$21,340	5.8%	\$105.0	\$85.0	\$95.0	2.249	498.00	505.00	0.28%
20	Sempra	48.3%	\$62,800	\$30,332	45.0%	\$95,000	\$42,750	7.1%	\$120.0	\$90.0	\$105.0	1.765	650.63	665.00	0.44%

(a) The Value Line Investment Survey (Mar. 7, Apr. 18, and May 9, 2025).

(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  $2 \times (1 + 5\text{-Yr. Change in Equity}) / (2 + 5\text{ Yr. Change in Equity})$ .

(e) Product of average year-end "r" for 2029 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 2029 BVPS.

UTILITY GROUP

		(a)	(b)	(c)		(d)	(e)		(f)		
		Market Return (R <sub>m</sub> )			Risk-Free Rate	Risk Premium	Beta	Unadjusted CAPM	Market Cap	Size Adjustment	Adjusted CAPM
	Company	Div Yield	Proj. Growth	R <sub>(m)</sub>							
1	Alliant Energy	1.7%	10.3%	12.0%	4.8%	7.2%	0.80	10.6%	\$16,300	0.49%	11.1%
2	American Elec Pwr	1.7%	10.3%	12.0%	4.8%	7.2%	0.70	9.8%	\$52,700	-0.01%	9.8%
3	Avista Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.75	10.2%	\$3,100	1.00%	11.2%
4	Black Hills Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.90	11.3%	\$4,100	0.74%	12.0%
5	CenterPoint Energy	1.7%	10.3%	12.0%	4.8%	7.2%	0.85	10.9%	\$21,200	0.33%	11.3%
6	CMS Energy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.70	9.8%	\$20,800	0.33%	10.2%
7	Dominion Energy	1.7%	10.3%	12.0%	4.8%	7.2%	0.75	10.2%	\$50,400	-0.01%	10.2%
8	DTE Energy Co.	1.7%	10.3%	12.0%	4.8%	7.2%	0.85	10.9%	\$25,800	0.33%	11.3%
9	Duke Energy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.65	9.5%	\$90,400	-0.01%	9.5%
10	Edison International	1.7%	10.3%	12.0%	4.8%	7.2%	0.90	11.3%	\$20,600	0.33%	11.6%
11	Entergy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.80	10.6%	\$32,700	0.33%	10.9%
12	Eversource Inc.	1.7%	10.3%	12.0%	4.8%	7.2%	0.75	10.2%	\$13,600	0.49%	10.7%
13	Eversource Energy	1.7%	10.3%	12.0%	4.8%	7.2%	0.85	10.9%	\$23,800	0.33%	11.3%
14	FirstEnergy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.75	10.2%	\$25,200	0.33%	10.5%
15	IDACORP, Inc.	1.7%	10.3%	12.0%	4.8%	7.2%	0.70	9.8%	\$6,100	0.74%	10.6%
16	NorthWestern Energy Grp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.80	10.6%	\$3,400	1.00%	11.6%
17	Otter Tail Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.90	11.3%	\$3,800	1.00%	12.3%
18	Pinnacle West Capital	1.7%	10.3%	12.0%	4.8%	7.2%	0.80	10.6%	\$10,600	0.49%	11.1%
19	Pub Sv Enterprise Grp.	1.7%	10.3%	12.0%	4.8%	7.2%	0.85	10.9%	\$45,000	0.33%	11.3%
20	Sempra	1.7%	10.3%	12.0%	4.8%	7.2%	0.90	11.3%	\$41,600	0.33%	11.6%
	Average							10.5%			11.0%

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from [www.valueline.com](http://www.valueline.com) (retrieved May 8, 2025).

(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 LSEG, as provided by [fidelity.com](http://fidelity.com) (retrieved May 8, 2025), [www.valueline.com](http://www.valueline.com) (retrieved May 8, 2025), and [www.zacks.com](http://www.zacks.com) (retrieved May 8, 2025). 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 Jun. 2025 based on data from Moody's Investors Service.

(d) The Value Line Investment Survey, Summary & Index (May 23, 2025).

(e) The Value Line Investment Survey (Mar. 7, Apr. 18, and May 9, 2025).

(f) Kroll, 2024 CRSP Deciles Size Premium, Cost of Capital Navigator (2025).

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	Adjusted	
	Company	Yield	Growth	Equity	Rate	Premium	Weight	$RP^1$	Beta	Weight	$RP^2$	Total RP	ECAPM	Cap	Adjustment	ECAPM
1	Alliant Energy	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.9%	\$16,300	0.49%	11.4%
2	American Elec Pwr	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	10.4%	\$52,700	-0.01%	10.4%
3	Avista Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.7%	\$3,100	1.00%	11.7%
4	Black Hills Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.90	75%	4.9%	6.7%	11.5%	\$4,100	0.74%	12.2%
5	CenterPoint Energy	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.85	75%	4.6%	6.4%	11.2%	\$21,200	0.33%	11.5%
6	CMS Energy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	10.4%	\$20,800	0.33%	10.7%
7	Dominion Energy	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.7%	\$50,400	-0.01%	10.6%
8	DTE Energy Co.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.85	75%	4.6%	6.4%	11.2%	\$25,800	0.33%	11.5%
9	Duke Energy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.65	75%	3.5%	5.3%	10.1%	\$90,400	-0.01%	10.1%
10	Edison International	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.90	75%	4.9%	6.7%	11.5%	\$20,600	0.33%	11.8%
11	Entergy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.9%	\$32,700	0.33%	11.3%
12	Evergy Inc.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.7%	\$13,600	0.49%	11.1%
13	Eversource Energy	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.85	75%	4.6%	6.4%	11.2%	\$23,800	0.33%	11.5%
14	FirstEnergy Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.75	75%	4.1%	5.9%	10.7%	\$25,200	0.33%	11.0%
15	IDACORP, Inc.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.70	75%	3.8%	5.6%	10.4%	\$6,100	0.74%	11.1%
16	NorthWestern Energy Grp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.9%	\$3,400	1.00%	11.9%
17	Otter Tail Corp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.90	75%	4.9%	6.7%	11.5%	\$3,800	1.00%	12.5%
18	Pinnacle West Capital	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.80	75%	4.3%	6.1%	10.9%	\$10,600	0.49%	11.4%
19	Pub Sv Enterprise Grp.	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.85	75%	4.6%	6.4%	11.2%	\$45,000	0.33%	11.5%
20	Sempra	1.7%	10.3%	12.0%	4.8%	7.2%	25%	1.8%	0.90	75%	4.9%	6.7%	11.5%	\$41,600	0.33%	11.8%
Average													10.9%			11.4%

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (retrieved May 8, 2025).

(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 LSEG, as provided by fidelity.com (retrieved May 8, 2025), www.valueline.com (retrieved May 8, 2025), and www.zacks.com (retrieved May 8, 2025). 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 Jun. 2025 based on data from Moody's Investors Service.

(d) Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 190.

(e) The Value Line Investment Survey, Summary & Index (May 23, 2025).

(f) The Value Line Investment Survey (Mar. 7, Apr. 18, and May 9, 2025).

(g) Kroll, 2024 CRSP Deciles Size Premium, Cost of Capital Navigator (2025).

## UTILITY RISK PREMIUM

Exhibit AMM-9

Page 1 of 3

### COST OF EQUITY ESTIMATE

#### **Current Equity Risk Premium**

(a) Avg. Yield over Study Period	7.74%
(b) Average Utility Bond Yield	<u>5.89%</u>
Change in Bond Yield	-1.85%
(c) Risk Premium/Interest Rate Relationship	<u>-0.4212</u>
Adjustment to Average Risk Premium	0.78%
(a) Average Risk Premium over Study Period	<u>3.90%</u>
<b>Adjusted Risk Premium</b>	<b>4.68%</b>

#### **Implied Cost of Equity**

(b) Baa Utility Bond Yield	6.06%
Adjusted Equity Risk Premium	<u>4.68%</u>
<b>Risk Premium Cost of Equity</b>	<b>10.74%</b>

(a) Exhibit AMM-9, page 2.

(b) Average bond yield on all utility bonds and 'Baa' subset for six-months ending Jun. 2025 based on data from Moody's Investors Service at [www.credittrends.com](http://www.credittrends.com).

(c) Exhibit AMM-9, page 3.

# UTILITY RISK PREMIUM

Exhibit AMM-9

Page 2 of 3

## AUTHORIZED RETURNS

	(a)	(b)	
Year	Allowed ROE	Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.54%	9.21%	3.33%
1992	12.09%	8.57%	3.52%
1993	11.46%	7.56%	3.90%
1994	11.21%	8.30%	2.91%
1995	11.58%	7.91%	3.67%
1996	11.40%	7.74%	3.66%
1997	11.33%	7.63%	3.70%
1998	11.77%	7.00%	4.77%
1999	10.72%	7.55%	3.17%

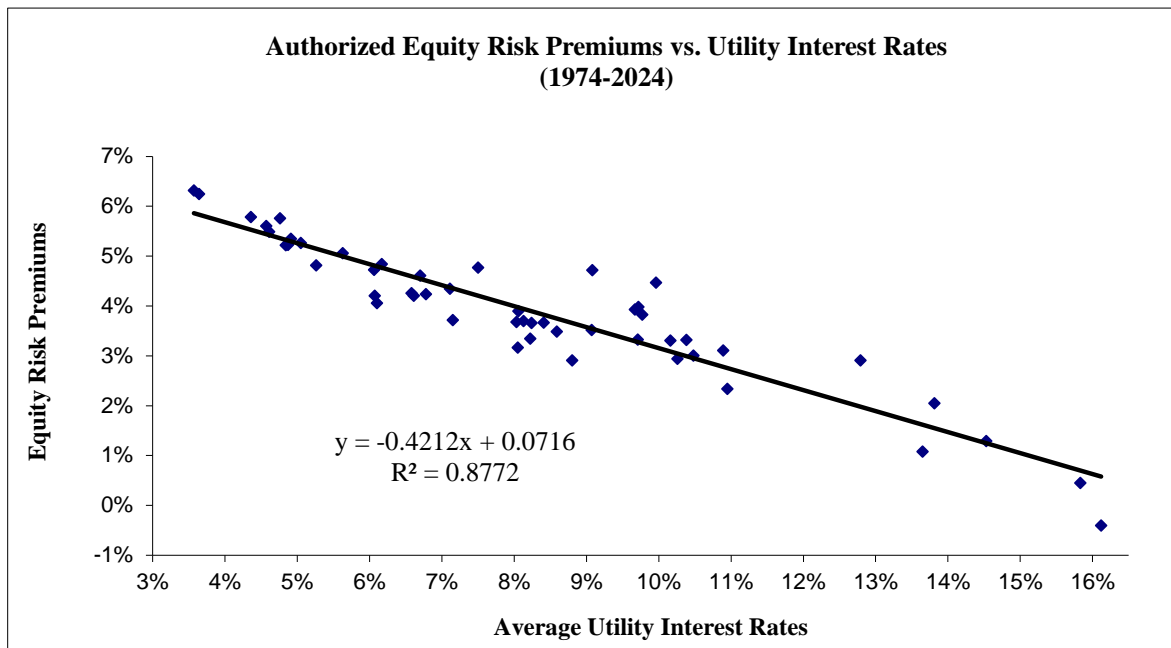
	(a)	(b)	
Year	Allowed ROE	Average Utility Bond Yield	Risk Premium
2000	11.58%	8.09%	3.49%
2001	11.07%	7.72%	3.35%
2002	11.21%	7.53%	3.68%
2003	10.96%	6.61%	4.35%
2004	10.81%	6.20%	4.61%
2005	10.51%	5.67%	4.84%
2006	10.34%	6.08%	4.26%
2007	10.32%	6.11%	4.21%
2008	10.37%	6.65%	3.72%
2009	10.52%	6.28%	4.24%
2010	10.29%	5.56%	4.73%
2011	10.19%	5.13%	5.06%
2012	10.02%	4.26%	5.76%
2013	9.82%	4.55%	5.27%
2014	9.76%	4.41%	5.35%
2015	9.60%	4.37%	5.23%
2016	9.60%	4.11%	5.49%
2017	9.68%	4.07%	5.61%
2018	9.56%	4.34%	5.22%
2019	9.65%	3.86%	5.79%
2020	9.39%	3.07%	6.32%
2021	9.39%	3.14%	6.25%
2022	9.58%	4.76%	4.82%
2023	9.66%	5.60%	4.06%
2024	<u>9.78%</u>	<u>5.57%</u>	<u>4.21%</u>
<b>Average</b>	<b>11.64%</b>	<b>7.74%</b>	<b>3.90%</b>

(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****Exhibit AMM-10****Page 1 of 1****UTILITY GROUP**

	(a)	(b)	(c)
<b>Company</b>	<b>Expected Return on Common Equity</b>	<b>Adjustment Factor</b>	<b>Adjusted Return on Common Equity</b>
1 Alliant Energy	12.0%	1.0156	12.2%
2 American Elec Pwr	11.0%	1.0119	11.1%
3 Avista Corp.	8.0%	1.0162	8.1%
4 Black Hills Corp.	8.5%	1.0267	8.7%
5 CenterPoint Energy	10.5%	1.0263	10.8%
6 CMS Energy Corp.	13.5%	1.0146	13.7%
7 Dominion Energy	11.5%	1.0229	11.8%
8 DTE Energy Co.	12.5%	1.0114	12.6%
9 Duke Energy Corp.	10.5%	1.0187	10.7%
10 Edison International	14.0%	1.0365	14.5%
11 Entergy Corp.	9.5%	1.0302	9.8%
12 Evergy Inc.	10.0%	1.0124	10.1%
13 Eversource Energy	11.5%	1.0267	11.8%
14 FirstEnergy Corp.	12.5%	1.0242	12.8%
15 IDACORP, Inc.	9.5%	1.0222	9.7%
16 NorthWestern Energy Grp.	8.0%	1.0186	8.1%
17 Otter Tail Corp.	11.5%	1.0081	11.6%
18 Pinnacle West Capital	9.0%	1.0262	9.2%
19 Pub Sv Enterprise Grp.	12.5%	1.0282	12.9%
20 Sempra	10.5%	1.0343	10.9%
<b>Average</b>	<b>10.8%</b>		<b>11.1%</b>

(a) The Value Line Investment Survey (Mar. 7, Apr. 18, and May 9, 2025).

(b) Adjustment to convert year-end return to an average rate of return from Exhibit AMM-6.

(c) (a) x (b).

**FLOTATION COST STUDY**

**Exhibit AMM-11**

**Page 1 of 1**

**ELECTRIC & GAS UTILITIES**

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Shares	Offering	Underwriting	Underwriting	Offering	Total	Gross Proceeds	Flotation
		Date	Issued	Price	Discount	Discount	Expense	Flotation	Before Flot.	Cost
					(per share)			Costs	Costs	(%)
1	LNT	Alliant Energy	11/14/2019	3,717,502	\$52.63	\$0.39500	\$1,468,413	\$500,000	\$1,968,413	1.006%
2	AEE	Ameren Corp.	8/5/2019	7,549,205	\$74.30	\$0.12000	\$905,905	\$750,000	\$1,655,905	0.295%
3	AEP	American Elec Pwr	4/2/2009	69,000,000	\$24.50	\$0.73500	\$50,715,000	\$400,000	\$51,115,000	3.024%
4	AVA	Avista Corp.	12/13/2006	3,162,500	\$25.05	\$0.48000	\$1,518,000	\$300,000	\$1,818,000	2.295%
5	BKH	Black Hills Corp.	2/25/2020	1,222,942	\$81.77	\$0.73590	\$899,963	\$230,000	\$1,129,963	1.130%
6	CNP	CenterPoint Energy	8/8/2024	9,754,194	\$25.63	\$0.27000	\$2,633,632	\$400,000	\$3,033,632	1.213%
7	CMS	CMS Energy Corp.	3/31/2005	23,000,000	\$12.25	\$0.42880	\$9,862,400	\$325,000	\$10,187,400	3.616%
8	ED	Consolidated Edison (a)	12/4/2024	7,000,000	\$96.66	\$0.87000	\$6,090,000	\$450,000	\$6,540,000	0.967%
		Con Ed "Follow-On Offering" (a)	3/5/2025	6,300,000	\$100.21	\$1.93900	\$12,215,700	\$400,000	\$12,615,700	1.998%
9	D	Dominion Energy (a)	3/29/2018	20,000,000	\$67.33	\$1.89420	\$37,884,000	\$450,000	\$38,334,000	2.847%
10	DTE	DTE Energy Co.	10/29/2019	2,400,000	\$126.00	\$3.15000	\$7,560,000	\$300,000	\$7,860,000	2.599%
11	DUK	Duke Energy Corp. (a)	11/18/2019	25,000,000	\$85.99	\$2.66000	\$66,500,000	\$592,000	\$67,092,000	3.121%
12	EIX	Edison International	5/13/2020	14,181,882	\$56.41	\$0.98718	\$14,000,000	\$1,000,000	\$15,000,000	1.875%
13	ETR	Entergy Corp.	6/8/2018	13,289,037	\$75.25	\$0.80000	\$10,631,230	\$650,000	\$11,281,230	1.128%
14	EVRG	Eversource Energy (a)					N/A			
15	ES	Eversource Energy (a)	6/12/2020	6,000,000	\$84.91	\$1.35000	\$8,100,000	\$600,000	\$8,700,000	1.708%
16	EXC	Exelon Corp. (a)	8/8/2022	11,300,000	\$43.32	\$0.99000	\$11,187,000	\$900,000	\$12,087,000	2.469%
17	FE	FirstEnergy Corp.	9/15/2003	32,200,000	\$30.00	\$0.97500	\$31,395,000	\$423,000	\$31,818,000	3.294%
18	FTS	Fortis Inc.					N/A			
19	HE	Hawaiian Elec.	9/24/2024	54,054,054	\$9.25	\$0.27750	\$15,000,000	\$650,000	\$15,650,000	3.130%
20	IDA	IDACORP, Inc.	12/10/2004	4,025,000	\$30.00	\$1.20000	\$4,830,000	\$300,000	\$5,130,000	4.248%
21	MGEE	MGE Energy	5/14/2020	1,300,000	\$56.00	\$2.38000	\$3,094,000	\$500,000	\$3,594,000	4.937%
22	NEE	NextEra Energy, Inc. (a)	11/3/2016	13,800,000	\$124.00	\$1.89000	\$26,082,000	\$750,000	\$26,832,000	1.568%
23	NWE	NorthWestern Energy Group	11/18/2021	6,074,767	\$53.50	\$1.60500	\$9,750,001	\$900,000	\$10,650,001	3.277%
24	OGE	OGE Energy Corp.	8/22/2003	5,324,074	\$21.60	\$0.79000	\$4,206,018	\$325,000	\$4,531,018	3.940%
25	OTTR	Otter Tail Corp.					N/A			
26	PCG	PG&E Corp.	12/3/2024	48,661,801	\$20.55	\$0.39045	\$19,000,000	\$750,000	\$19,750,000	1.975%
27	PNW	Pinnacle West Capital	3/1/2024	9,774,436	\$66.50	\$1.99500	\$19,500,000	\$550,000	\$20,050,000	3.085%
28	POR	Portland General Elec.	10/27/2022	10,100,000	\$43.00	\$1.23625	\$12,486,125	\$515,000	\$13,001,125	2.994%
29	PPL	PPL Corp.	5/10/2018	55,000,000	\$27.00	\$0.29430	\$16,186,500	\$1,000,000	\$17,186,500	1.157%
30	PEG	Pub Sv Enterprise Grp.	10/2/2003	9,487,500	\$41.75	\$1.25250	\$11,883,094	\$350,000	\$12,233,094	3.088%
31	SRE	Sempra Energy	11/8/2023	17,142,858	\$70.00	\$1.15500	\$19,800,001	\$600,000	\$20,400,001	1.700%
32	SO	Southern Company (a)	8/18/2016	32,500,000	\$49.30	\$1.66000	\$53,950,000	\$557,000	\$54,507,000	3.402%
33	PNM	TXNM Energy (a)	1/7/2020	5,375,000	\$47.21	\$1.99000	\$10,696,250	\$750,000	\$11,446,250	4.511%
34	WEC	WEC Energy Group					N/A			
35	XEL	Xcel Energy Inc. (a)	11/5/2024	18,320,610	\$65.50	\$1.06440	\$19,500,457	\$1,200,000	\$20,700,457	1.725%
<b>Average</b>										<b>2.479%</b>
1	ATO	Atmos Energy Corp.	11/30/2018	7,008,087	\$92.75	\$0.97690	\$6,846,200	\$1,000,000	\$7,846,200	1.207%
2	CPK	Chesapeake Utilities	11/14/2023	3,859,649	\$85.50	\$2.77875	\$10,725,000	\$1,000,000	\$11,725,000	3.553%
3	NJR	New Jersey Resources	12/4/2019	5,700,000	\$41.25	\$1.23750	\$7,053,750	\$500,000	\$7,553,750	3.213%
4	NI	NiSource Inc.	5/3/2017	N/A	N/A	N/A	\$10,000,000	\$57,950	\$10,057,950	2.012%
5	NWN	Northwest Nat. Holding Co.	3/30/2022	2,500,000	\$50.00	\$1.62500	\$4,062,500	\$450,000	\$4,512,500	3.610%
6	OGS	ONE Gas, Inc.					N/A			
7	SWX	Southwest Gas	3/9/2023	3,576,180	\$60.12	\$2.02910	\$7,256,427	\$538,000	\$7,794,427	3.625%
8	SR	Spire Inc.	6/15/2023	1,744,549	\$64.20	\$0.60000	\$1,046,729	\$450,000	\$1,496,729	1.336%
<b>Average</b>										<b>2.651%</b>
<b>Average - Electric &amp; Gas</b>										<b>2.510%</b>

Column Notes:

(1-4) SEC Form 424B for each company (through Mar 17, 2025).

(5) Column (2) \* Column (4)

(6) SEC Form 424B for each company (through Mar 17, 2025).

(7) Column (5) + Column (6)

(8) Column (2) \* Column (3)

(9) Column (7) / Column (8)

Note (a): Underwriting discount computed as the difference between the current market price and the price offered to the issuing company by the underwriters.

**DIVIDEND YIELD**

			(a)	(b)	
	Company	Industry Group	Price	Dividends	Yield
1	Abbott Labs.	Med Supp Non-Invasive	\$130.21	\$2.36	1.8%
2	AbbVie Inc.	Drug	\$183.35	\$6.56	3.6%
3	Amdocs Ltd.	IT Services	\$87.08	\$1.92	2.2%
4	Amgen	Biotechnology	\$279.58	\$9.52	3.4%
5	AptarGroup	Packaging & Container	\$148.50	\$1.85	1.2%
6	Automatic Data Proc.	Human Resources	\$299.79	\$6.16	2.1%
7	Bristol-Myers Squibb	Drug	\$49.08	\$2.48	5.1%
8	Brown-Forman 'B'	Beverage	\$34.34	\$1.00	2.9%
9	Church & Dwight	Household Products	\$98.46	\$1.18	1.2%
10	Cisco Systems	Telecom. Equipment	\$58.24	\$1.64	2.8%
11	CME Group	Brokers & Exchanges	\$269.13	\$5.00	1.9%
12	Coca-Cola	Beverage	\$71.42	\$2.04	2.9%
13	Colgate-Palmolive	Household Products	\$91.67	\$2.08	2.3%
14	Costco Wholesale	Retail Store	\$986.38	\$5.20	0.5%
15	Electronic Arts	Entertainment Tech	\$146.50	\$0.76	0.5%
16	Gallagher (Arthur J.)	Financial Svcs. (Div.)	\$329.99	\$2.60	0.8%
17	Gen'l Dynamics	Aerospace/Defense	\$272.17	\$6.00	2.2%
18	Gen'l Mills	Food Processing	\$56.14	\$2.43	4.3%
19	Gilead Sciences	Drug	\$103.25	\$3.16	3.1%
20	Hershey Co.	Food Processing	\$165.20	\$5.63	3.4%
21	Home Depot	Retail Building Supply	\$359.98	\$9.20	2.6%
22	Hormel Foods	Food Processing	\$29.83	\$1.16	3.9%
23	Int'l Business Mach.	Computer Software	\$243.94	\$7.20	3.0%
24	Johnson & Johnson	Drug	\$153.60	\$5.20	3.4%
25	Kimberly-Clark	Household Products	\$135.36	\$5.04	3.7%
26	Lilly (Eli)	Drug	\$785.47	\$6.00	0.8%
27	Lockheed Martin	Aerospace/Defense	\$467.26	\$13.20	2.8%
28	Marsh & McLennan	Financial Svcs. (Div.)	\$225.52	\$3.36	1.5%
29	McDonald's Corp.	Restaurant	\$312.85	\$7.28	2.3%
30	McKesson Corp.	Med Supp Non-Invasive	\$695.38	\$3.11	0.4%
31	Merck & Co.	Drug	\$79.39	\$3.24	4.1%
32	Microsoft Corp.	Computer Software	\$406.79	\$3.50	0.9%
33	Mondelez Int'l	Food Processing	\$66.42	\$1.88	2.8%
34	NewMarket Corp.	Chemical (Specialty)	\$598.19	\$11.00	1.8%
35	Northrop Grumman	Aerospace/Defense	\$492.22	\$8.84	1.8%
36	PepsiCo, Inc.	Beverage	\$136.65	\$5.42	4.0%
37	Procter & Gamble	Household Products	\$162.50	\$4.23	2.6%
38	Progressive Corp.	Insurance (Prop/Cas.)	\$275.09	\$0.40	0.1%
39	Republic Services	Environmental	\$244.07	\$2.32	1.0%
40	Roper Tech.	Computer Software	\$560.99	\$3.47	0.6%
41	Thermo Fisher Sci.	Med Supp Non-Invasive	\$424.70	\$1.72	0.4%
42	T-Mobile US	Telecom. Services	\$249.52	\$3.64	1.5%
43	Verizon Communic.	Telecom. Services	\$43.31	\$2.72	6.3%
44	Walmart Inc.	Retail Store	\$94.75	\$0.94	1.0%
45	Waste Management	Environmental	\$229.09	\$3.30	1.4%
<b>Average</b>					<b>2.3%</b>

(a) Average of closing prices for 30 trading days ended May 20, 2025.

(b) The Value Line Investment Survey, *Summary & Index* (May 23, 2025).

**GROWTH RATES**

		(a)	(b)	(c)
	Company	V Line	IBES	Zacks
1	Abbott Labs.	6.00%	10.10%	10.28%
2	AbbVie Inc.	5.00%	16.50%	12.26%
3	Amdocs Ltd.	6.50%	8.50%	9.81%
4	Amgen	5.50%	5.10%	5.31%
5	AptarGroup	10.50%	8.30%	6.23%
6	Automatic Data Proc.	7.00%	9.30%	9.66%
7	Bristol-Myers Squibb	2.50%	46.50%	5.00%
8	Brown-Forman 'B'	9.50%	-2.30%	3.20%
9	Church & Dwight	6.00%	6.00%	7.15%
10	Cisco Systems	5.50%	5.00%	5.41%
11	CME Group	5.50%	6.80%	6.53%
12	Coca-Cola	7.00%	6.10%	6.33%
13	Colgate-Palmolive	10.00%	4.90%	5.16%
14	Costco Wholesale	10.00%	10.60%	9.36%
15	Electronic Arts	12.50%	10.30%	12.02%
16	Gallagher (Arthur J.)	14.50%	14.60%	n/a
17	Gen'l Dynamics	9.50%	11.50%	9.96%
18	Gen'l Mills	3.00%	-1.80%	10.86%
19	Gilead Sciences	6.50%	28.30%	19.49%
20	Hershey Co.	5.00%	-8.40%	4.61%
21	Home Depot	6.00%	5.10%	7.05%
22	Hormel Foods	5.00%	6.80%	5.49%
23	Int'l Business Mach.	6.00%	3.70%	4.35%
24	Johnson & Johnson	4.50%	5.30%	6.23%
25	Kimberly-Clark	6.50%	3.90%	3.97%
26	Lilly (Eli)	25.50%	41.90%	31.21%
27	Lockheed Martin	9.50%	9.30%	10.52%
28	Marsh & McLennan	10.50%	8.50%	8.52%
29	McDonald's Corp.	8.50%	7.50%	7.82%
30	McKesson Corp.	10.00%	12.30%	13.45%
31	Merck & Co.	13.50%	13.70%	12.15%
32	Microsoft Corp.	12.00%	13.70%	14.76%
33	Mondelez Int'l	6.50%	2.30%	4.27%
34	NewMarket Corp.	5.50%	n/a	n/a
35	Northrop Grumman	7.50%	4.20%	3.28%
36	PepsiCo, Inc.	6.00%	3.60%	4.42%
37	Procter & Gamble	4.50%	4.30%	4.96%
38	Progressive Corp.	23.50%	n/a	10.22%
39	Republic Services	12.00%	9.20%	9.46%
40	Roper Tech.	7.50%	7.90%	10.50%
41	Thermo Fisher Sci.	8.00%	7.20%	8.48%
42	T-Mobile US	18.00%	17.70%	17.21%
43	Verizon Communic.	0.50%	2.60%	2.87%
44	Walmart Inc.	10.00%	8.10%	7.90%
45	Waste Management	7.50%	10.50%	9.98%

(a) www.valueline.com (retrieved May 20, 2025).

(b) LSEG Stock Reports Plus, as provided by fidelity.com (retrieved May 20, 2025).

(c) www.zacks.com (retrieved May 20, 2025).

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)
	Company	V Line	IBES	Zacks
1	Abbott Labs.	7.8%	11.9%	12.1%
2	AbbVie Inc.	8.6%	20.1%	15.8%
3	Amdocs Ltd.	8.7%	10.7%	12.0%
4	Amgen	8.9%	8.5%	8.7%
5	AptarGroup	11.7%	9.5%	7.5%
6	Automatic Data Proc.	9.1%	11.4%	11.7%
7	Bristol-Myers Squibb	7.6%	51.6%	10.1%
8	Brown-Forman 'B'	12.4%	0.6%	6.1%
9	Church & Dwight	7.2%	7.2%	8.3%
10	Cisco Systems	8.3%	7.8%	8.2%
11	CME Group	7.4%	8.7%	8.4%
12	Coca-Cola	9.9%	9.0%	9.2%
13	Colgate-Palmolive	12.3%	7.2%	7.4%
14	Costco Wholesale	10.5%	11.1%	9.9%
15	Electronic Arts	13.0%	10.8%	12.5%
16	Gallagher (Arthur J.)	15.3%	15.4%	n/a
17	Gen'l Dynamics	11.7%	13.7%	12.2%
18	Gen'l Mills	7.3%	2.5%	15.2%
19	Gilead Sciences	9.6%	31.4%	22.6%
20	Hershey Co.	8.4%	-5.0%	8.0%
21	Home Depot	8.6%	7.7%	9.6%
22	Hormel Foods	8.9%	10.7%	9.4%
23	Int'l Business Mach.	9.0%	6.7%	7.3%
24	Johnson & Johnson	7.9%	8.7%	9.6%
25	Kimberly-Clark	10.2%	7.6%	7.7%
26	Lilly (Eli)	26.3%	42.7%	32.0%
27	Lockheed Martin	12.3%	12.1%	13.3%
28	Marsh & McLennan	12.0%	10.0%	10.0%
29	McDonald's Corp.	10.8%	9.8%	10.1%
30	McKesson Corp.	10.4%	12.7%	13.9%
31	Merck & Co.	17.6%	17.8%	16.2%
32	Microsoft Corp.	12.9%	14.6%	15.6%
33	Mondelez Int'l	9.3%	5.1%	7.1%
34	NewMarket Corp.	7.3%	n/a	n/a
35	Northrop Grumman	9.3%	6.0%	5.1%
36	PepsiCo, Inc.	10.0%	7.6%	8.4%
37	Procter & Gamble	7.1%	6.9%	7.6%
38	Progressive Corp.	23.6%	n/a	10.4%
39	Republic Services	13.0%	10.2%	10.4%
40	Roper Tech.	8.1%	8.5%	11.1%
41	Thermo Fisher Sci.	8.4%	7.6%	8.9%
42	T-Mobile US	19.5%	19.2%	18.7%
43	Verizon Communic.	6.8%	8.9%	9.2%
44	Walmart Inc.	11.0%	9.1%	8.9%
45	Waste Management	8.9%	11.9%	11.4%
	<b>Average (b)</b>	<b>10.1%</b>	<b>10.2%</b>	<b>10.5%</b>

(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;	)	Case No. 2025-00257
(3) Approval Of Certain Regulatory And Accounting	)	
Treatments; and (4) All Other Required Approvals	)	
And Relief	)	

**DIRECT TESTIMONY OF**

**BRIAN C. CIBOREK**

**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
BRIAN C. CIBOREK ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**DIRECT TESTIMONY OF  
BRIAN C. CIBOREK ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

A. My name is Brian C. Ciborek. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation (“AEPSC”) as a Senior Manager 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 earned a Bachelor of Science Degree in Accounting from Franklin University in May 1998. I have been a Certified Public Accountant since February 2007. Starting with my hiring by AEPSC in December 2008, I held staff and leadership positions within AEP’s Financial Reporting department. I was a Principal Accountant in Financial Reporting from December 2008 through December 2018. In January 2019, I was promoted to Senior Manager of Financial Reporting. For AEP and its reporting subsidiaries, I assisted in leading Financial Reporting in the preparation and filing of quarterly and annual reports in accordance with both Generally Accepted Accounting Principles (“GAAP”) and the reporting requirements of both the Securities and Exchange Commission and the Federal

1 Energy Regulatory Commission (“FERC”). In August 2024, I started my current role as  
2 Senior Manager within the AEPSC Regulatory Accounting Services function.

3 **Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER IN THE REGULATORY**  
4 **ACCOUNTING SERVICES GROUP?**

5 A. My primary responsibilities in Regulatory Accounting Services involve providing AEP  
6 operating companies, including Kentucky Power, with accounting support for regulatory  
7 filings. This accounting support includes the preparation of total company cost-of-service  
8 and related adjustments, accounting schedules, testimony, and discovery responses. I also  
9 monitor regulatory proceedings, settlements, orders, and legislation for accounting  
10 implications and participate in determining the appropriate regulatory accounting and  
11 financial reporting treatment of regulatory transactions.

12 **Q. HAVE YOU PREVIOUSLY TESTIFIED OR SUBMITTED TESTIMONY IN A**  
13 **REGULATORY PROCEEDING?**

14 A. Yes. I have filed testimony with the Virginia State Corporation Commission in Case  
15 No. PUR-2025-00049. I have also filed testimony with the Public Utilities Commission of  
16 Ohio in Case No. 25-0550-EL-UNC.

### **III. PURPOSE OF TESTIMONY**

17 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
18 **PROCEEDING?**

19 A. The purpose of my Direct Testimony is to support certain known and measurable  
20 adjustments to the Company’s revenues and operating expenses, rate base, and  
21 capitalization for the test year ended (12 months ended) May 31, 2025. I have provided the  
22 adjustments to revenues, operating expenses, and rate base to Company Witness Cost for

1 inclusion in the computation of the Company's jurisdictional revenue requirement. I have  
2 provided the adjustment to capitalization to Company Witness Cost to present in Section  
3 V, Schedule 3.

#### IV. SUMMARY OF ADJUSTMENTS

4 **Q. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS THAT YOU HAVE**  
5 **PREPARED FOR THIS CASE.**

6 A. I have prepared three types of adjustments in this case, including test year revenue and  
7 operating expense adjustments, rate base adjustments, and a capitalization adjustment. The  
8 adjustments are described in detail in the Revenue and Operating Expense Adjustments,  
9 Rate Base Adjustment, and Capitalization Adjustment sections of my Direct Testimony.  
10 The purpose of these adjustments is to accurately reflect the going-level of revenue,  
11 expenses and rate base amounts as they relate to the test year ending May 31, 2025.

12 **Q. HOW DID YOU DETERMINE THE APPROPRIATE ALLOCATION FACTORS**  
13 **FOR THE ADJUSTMENTS THAT YOU ARE SPONSORING?**

14 A. For all of the adjustments that I sponsor in my Direct Testimony below, I calculated the  
15 total Company adjustments and applied operations and maintenance ("O&M") factors (as  
16 applicable). As explained by Company Witness Cost, all going-level adjustments are  
17 allocated 100% to the Company's retail jurisdiction.

18 **Q. DO YOU SUPPORT ANY OF THE INFORMATION PROVIDED IN SECTION IV**  
19 **OR SECTION V OF THIS APPLICATION?**

20 A. Yes. I support various adjustments that are located in Section V, Exhibit 2. I also support  
21 the Company's balance sheet information provided in Section IV.

**V. REVENUE AND OPERATING EXPENSE ADJUSTMENTS**

1 **Q. WHAT TYPES OF REVENUE AND OPERATING EXPENSE ADJUSTMENTS DID**  
2 **YOU PREPARE?**

3 A. The adjustments to test year revenue and operating expense that I prepared fall into five  
4 broad categories: (1) Rider and Surcharge Adjustments, (2) Payroll and Benefit  
5 Adjustments, (3) Depreciation and Asset Retirement Obligation (“ARO”) Expense  
6 Adjustments, (4) Amortization of Regulatory Deferrals, and (5) Other O&M Adjustments.

7 **Q. CAN YOU PROVIDE A LIST OF THE REVENUE AND OPERATING EXPENSE**  
8 **ADJUSTMENTS THAT YOU ARE SPONSORING?**

9 A. Yes. The following table identifies the revenue and operating expense adjustments that I  
10 am sponsoring. The details supporting the calculations of these adjustments are included  
11 on referenced pages of Exhibit 2 to Section V of the Application.

Category	Adjustment Description	Reference in Section V, Exhibit 2
Rider and Surcharge Adjustments	Remove Tariff D.R. Revenues and Expenses	W07
	Remove Tariff P.P.A. Revenues and Non-Transmission	W10
	Remove Tariff D.S.M.C. Revenues and Expenses	W11
	Remove Tariff R.E.A. Revenues and Expenses	W12
	Remove Tariff K.E.D.S. Revenues and Expenses	W13
Payroll and Benefit Adjustments	Adjust Pension and OPEB Expense	W26
	Adjust Employee Related Group Benefit Expense	W27
	Remove Severance Expense	W29
	KPCo Incentive Compensation Expense	W30
	KPCo Annualization of Payroll Expense	W31
	KPCo Overtime Related to Employee Merit Increases	W32
	KPCo Medicare Tax Expense	W33
	KPCo Social Security Tax Expense	W34
	KPCo Social Security Tax Base	W35
Depreciation and Asset Retirement Obligation Expense Adjustments	Annualization of Depreciation Expense (Excluding ARO Depreciation) at Existing Rates	W37
	Annualization of ARO Depreciation Expense	W38
	Annualization of ARO Accretion Expense	W39
	Annualization of Depreciation Expense (Excluding ARO Depreciation) at Updated Rates	W48
	Remove Mitchell Plant from Rate Base and Cost-of-Service Based on Proposal to Recover Through a Rider	W49
Amortization of Regulatory Deferrals	Amortization of NERC Compliance and Cybersecurity Cost Deferral	W28
	Request to Defer and Amortize Kentucky Power Pension Settlement Costs	W47
Other O&M Adjustments	Remove Joint Use Pole Rental Revenue and Expense Related to a Prior Period	W17
	Adjust Interest on Customer Deposits	W20
	Annualization of Lease Expense	W25
	AFUDC Offset	W41
	Remove Pension Settlement Costs from Rate Base	W46

**Rider and Surcharge Adjustments**

1 **Q. DID YOU MAKE ANY COST-OF-SERVICE ADJUSTMENTS FOR RIDERS WITH**  
2 **OVER-/UNDER-RECOVERY ACCOUNTING?**

3 A. Yes. For riders with over-/under-recovery accounting, I made certain adjustments to  
4 remove revenue and expense amounts related to the over-/under-recovery in order to avoid  
5 including certain rider-related amounts in the determination of the Company's base rates.  
6 This ensures that there is no double-counting of expense or revenues that are recovered  
7 through riders rather than base rates.

8 **Q. PLEASE DESCRIBE THE BASIS FOR OVER-/UNDER-RECOVERY**  
9 **ACCOUNTING.**

10 A. Financial Accounting Standards Board's ("FASB") Accounting Standards Codification  
11 ("ASC") 980-340-25-1 (regulatory assets) requires deferral accounting based on the  
12 existence of a regulatory asset when there is probability of recovery from customers in the  
13 future for an under-recovery of costs. ASC 980-405-25-1 (regulatory liabilities) requires  
14 deferral accounting based on the existence of a regulatory liability when a true-up to actual  
15 costs results in an over-recovery and there is a probability of refund to customers in the  
16 future.

17 **Q. FOR WHICH RIDERS DID YOU MAKE TEST YEAR COST-OF-SERVICE**  
18 **ADJUSTMENTS RELATED TO OVER-/UNDER-RECOVERY?**

19 A. I made adjustments to the test year cost-of-service for the Decommissioning Rider ("Tariff  
20 D.R."), Tariff Purchase Power Adjustment ("Tariff P.P.A."), and Tariff Demand-Side  
21 Management Adjustment Clause ("Tariff D.S.M.C.").

1   **Q.   PLEASE DESCRIBE THE ADJUSTMENTS THAT YOU ARE SPONSORING**  
2   **RELATED TO TARIFF D.R. (W07).**

3   A.   Because the Company recovers the costs associated with the decommissioning of  
4   coal-related assets at Big Sandy through Tariff D.R. and not through base rates, any  
5   revenues and expenses related to Tariff D.R. must be removed from the Company's  
6   cost-of-service. Effective January 16, 2024, as ordered in Case No. 2023-00159, the  
7   Company suspended collection of the Decommissioning Rider Regulatory Asset  
8   predicated by the Public Service Commission of Kentucky's ("Commission") approval to  
9   securitize those costs, which was completed in June 2025. Accordingly, I made the  
10   following adjustments relating to Tariff D.R. revenue and expense for the test year ended  
11   May 31, 2025:

- 12       1.   A decrease to test year revenue of \$5,276 in Accounts 440–444 to remove Tariff D.R.  
13           charges from revenue.
- 14       2.   A removal of both test year Big Sandy coal-related O&M expense of \$7,671 in Account  
15           501 and removal of the corresponding deferral of Big Sandy coal-related O&M expense  
16           of \$7,671 in Account 512. This removal of offsetting O&M expense and the deferral of  
17           O&M expense had no impact on test year cost-of-service.
- 18       3.   A decrease in test year amortization expense of \$209,318 in Account 407.3 to remove  
19           amortization expense of the net Tariff D.R. regulatory asset.

1 **Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE**  
2 **SPONSORING RELATED TO TARIFF P.P.A. (W10).**

3 A. Because the Company recovers certain purchased power costs through Tariff P.P.A. and  
4 not through base rates, any revenues and expenses related to Tariff P.P.A. must be removed  
5 from the Company's cost-of-service. I made the following adjustments relating to Tariff  
6 P.P.A. revenue and non-OATT expenses for the test year ended May 31, 2025:

7 1. A decrease to test year revenue of \$14,265,129 in Accounts 440–444 to remove Tariff  
8 P.P.A. revenues.

9 2. A decrease to test year revenue of \$2,506,318 in Accounts 440–444 to remove  
10 estimated Rockport Offset Revenue recognized in accordance with Generally Accepted  
11 Accounting Principles but not yet recovered (which would be recovered through Tariff  
12 PPA).

13 3. An increase to test year O&M expense of \$3,880,379 in Account 555 to remove the net  
14 annual cost of credits provided to customers under Tariff Contract Service-Interruptible  
15 Power ("C.S.-I.R.P") and Rider Demand Response Service ("D.R.S.").

16 4. A decrease to test year O&M expense of \$3,268,780 in Account 555 to remove deferral  
17 of the net test year capacity charges related to Tariff P.P.A.

18 5. A decrease to test year O&M expense of \$4,174,374 in Account 566 to remove deferral  
19 of the net test year over-recovery of expenses related to Tariff P.P.A.

20 Section V, Exhibit 2, W10, Lines 12 through 16 sets forth a reconciliation of test year  
21 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. (W11).**

A. Tariff D.S.M.C. recovers lost revenue, incentives and program costs as 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 May 31, 2025, are described below:

1. Decrease in test year other electric revenues of \$573,590 in Account 456, composed of the following:

- Removal of Demand Side Management ("DSM") Revenues of \$529,138.
- Removal of DSM Over/Under Recovery (Incentives & Lost Revenue) of \$6,494.
- Removal of DSM Incentive & Lost Revenue Accrued of \$37,958.

2. Decrease in test year O&M expense of \$515,763 in Account 908, composed of the following items related to program costs:

- Removal of DSM Over/Under Recovery (O&M Program Cost) of \$515,763.
- Removal of DSM O&M Program Cost Expense of \$276,014.
- Removal of DSM O&M Program Cost Over/Under Deferral of \$276,014.

The net DSM adjustments result in decreases of \$573,590 in test year revenue and \$515,763 in test year expense.

1 **Q. DID YOU MAKE ANY COST-OF-SERVICE ADJUSTMENTS FOR CERTAIN**  
2 **RIDERS WITHOUT OVER-/UNDER-RECOVERY ACCOUNTING?**

3 A. Yes. I made adjustments to test year cost-of-service for Tariff Residential Energy  
4 Assistance (“Tariff R.E.A.”) and Tariff Kentucky Economic Development Surcharge  
5 (“Tariff K.E.D.S.”).

6 **Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE**  
7 **SPONSORING RELATED TO TARIFF R.E.A. (W12).**

8 A. For this adjustment, test year retail Tariff R.E.A. revenue of \$628,079 recorded to Accounts  
9 440–444 is removed and corresponding expense of \$628,079 recorded as O&M expense to  
10 Account 908 is also removed.

11 **Q. PLEASE DESCRIBE THE GOING-LEVEL ADJUSTMENTS THAT YOU ARE**  
12 **SPONSORING RELATED TO THE COMPANY’S TARIFF K.E.D.S. (W13).**

13 A. For this adjustment, test year retail Tariff K.E.D.S. revenue of \$373,894 in Accounts  
14 440–444 is removed and corresponding expense of \$373,894 recorded as O&M expense to  
15 Account 908 is also removed.

16 **Q. IF THE GENERATION RIDER (“GR”) PROPOSED BY COMPANY WITNESS**  
17 **WOLFFRAM IS APPROVED, WOULD A REGULATORY ASSET OR**  
18 **REGULATORY LIABILITY BE CREATED TO ACCOUNT FOR THE**  
19 **TEMPORARY DIFFERENCES BETWEEN GR REVENUES AND ACTUAL GR**  
20 **COSTS ELIGIBLE FOR RECOVERY THROUGH THE GR?**

21 A. Yes. The Company would defer the cumulative monthly difference between GR revenues  
22 and actual incurred GR costs eligible for recovery through the GR, as a regulatory asset or  
23 regulatory liability on the books and records of the Company. This deferral—a regulatory

1 liability representing an over-recovery or a regulatory asset representing an  
2 under-recovery—is a timing difference between eligible costs incurred for GR projects and  
3 GR revenues. The Company requests specific provisions in the final order in this  
4 proceeding authorizing the creation of a regulatory asset or a regulatory liability for GR  
5 under-recoveries or GR over-recoveries, respectively. Company Witness Wolfram  
6 supports the proposed Generation Rider further in his Direct Testimony.

**Payroll and Benefit Adjustments**

7 **Q. ARE SPECIAL CONSIDERATIONS NECESSARY WHEN CALCULATING**  
8 **GOING-LEVEL COST-OF-SERVICE ADJUSTMENTS FOR PAYROLL AND**  
9 **BENEFIT RELATED ISSUES?**

10 A. Yes. The Company owns an undivided 50% interest in the Mitchell Plant. Through August  
11 2022, the Company was also the operator of the Mitchell Plant. In September 2022,  
12 Wheeling Power Company (“Wheeling Power”), an affiliated AEP subsidiary company  
13 and owner of the remaining 50% undivided interest in the Mitchell Plant, became operator  
14 of the Mitchell Plant, pursuant to the September 1, 2022, Written Consent Action of the  
15 Mitchell Operating Committee. The plant operator initially records 100% of all Mitchell  
16 Plant labor costs charged by employees. Then, the plant operator bills the other joint owner  
17 of the plant its share of Mitchell Plant labor costs, in accordance with the Mitchell  
18 Operating Agreement, including the September 1, 2022, Written Consent Action of the  
19 Mitchell Operating Committee. The Mitchell Plant Operating Agreement is included as  
20 Exhibit V to Section II of the Company’s Application.

21 Thus, all of the payroll and benefit cost-of-service adjustments discussed below  
22 properly include Kentucky Power’s ownership share of generation plant-related labor costs

and are inclusive of amounts properly billed or allocated from Wheeling Power for Kentucky Power's ownership share of Mitchell Plant.

**Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR PENSION AND OTHER POST EMPLOYMENT BENEFITS ("OPEB") (W26).**

A. This adjustment accounts for known changes from test year pension and OPEB costs related to both active and inactive Company employees, including the Company's 50% ownership share of related Mitchell Plant employee costs billed pursuant to the Mitchell Operating Agreement (discussed above). This adjustment increases operating expense for the test year ended May 31, 2025, by \$4,985,007 to reflect the ASC 715 pension and OPEB expense reported in the 2025 actuarial study, as provided by the Company's third-party actuary (Willis Towers Watson). This adjustment was determined by comparing the amounts from the 2025 actuarial study, after an allocation to expense based on Kentucky Power's O&M payroll percentage, to Kentucky Power's test year pension and OPEB expense.

Additionally, consistent with Commission orders in Case Nos. 2020-00174<sup>1</sup> and 2023-00159,<sup>2</sup> the Company removed the current annual level of cost savings related to the

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<sup>1</sup> See Order at 11–12, *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. Jan. 13, 2021).

<sup>2</sup> See Order at 20–21, *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 (Ky. P.S.C. Jan. 19, 2024) ("As noted in at least one previous rate case, while the Commission acknowledges the assertion that there has been cash outlay to finance these prepaid assets, the Commission finds that a more reasonable method of measuring and recording Kentucky Power's pension and OPEB amounts for ratemaking purposes would be to remove the expenses attributed to these amounts for the test period because it reflects the actual amounts expended for pensions and OPEB expenses in the test period, rather than an expected future liability. As a result of this finding, the Commission finds reasonable a revenue requirement

1 Company's Prepaid Pension and OPEB Assets from cost-of-service and excluded the  
2 Company's Prepaid Pension and OPEB Assets from rate base. The current annual level of  
3 cost savings related to the Company's Prepaid Pension and OPEB Assets was calculated  
4 using the allowed methodology in Case No. 2023-00159.

5 **Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR EMPLOYEE**  
6 **GROUP BENEFITS (W27).**

7 A. As further explained by Company Witness Carlin, this adjustment accounts for known  
8 changes from test year values in medical, dental, life and long-term disability coverage for  
9 Company employees, including the Company's 50% ownership share of related Mitchell  
10 Plant employee costs billed pursuant to the Mitchell Operating Agreement (discussed  
11 above). The adjustment is based on the number of employees enrolled in each plan as of  
12 May 31, 2025, and actual cost per employee for 2025 compared to actual Company  
13 medical, dental, life and long-term disability coverage costs for the test year ended May 31,  
14 2025. After applying corresponding O&M allocation factors, the net cost-of-service  
15 decrease for group benefit expense is \$61,787.

16 **Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT RELATED TO**  
17 **SEVERANCE EXPENSE (W29).**

18 A. This cost-of-service adjustment was made to decrease payroll expense for Company  
19 severance expense recorded in the test year. The decrease in cost-of-service for severance  
20 expense is \$3,086,549.

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increase, as agreed to in the Settlement, which reflects a decrease . . . for the removal of the prepaid pension and prepaid OPEB asset and a corresponding increase . . . for Kentucky Power's applicable test-year pension and OPEB expenses.").

**Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR THE COMPANY'S INCENTIVE COMPENSATION (W30).**

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").

As further explained by Company Witness Carlin, the incentive compensation cost-of-service adjustment increases test year ICP and PSU expense to reflect expenses at a level of 1.0 of the incentive target to be paid to Company employees<sup>3</sup> 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 Company employees<sup>3</sup> subject to meeting performance goals. The cost-of-service increase for incentive compensation expense (related to ICP & PSU) is \$836,596.

**Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR ANNUALIZATION OF PAYROLL EXPENSE (W31).**

A. This adjustment increases O&M expenses to reflect the annualized base payroll expense for the Company employees at the test year-end resulting in an O&M expense increase of \$2,120,142, which is comprised of two separate adjustments to payroll expense. First, base

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<sup>3</sup> Company employees, and the Company's 50% ownership share of related Mitchell Plant employee costs billed pursuant to the Mitchell Operating Agreement (discussed above).

1 payroll expense in the test year was updated using the actual employees on the payroll in  
2 the last pay period of May 2025 and their base payroll amounts at that time ("May 2025  
3 Base Payroll"), resulting in a calculated increase in payroll expense of \$1,613,268. Second,  
4 annual merit increases and promotions effective in April, May, and June 2026, as approved  
5 by the Company and provided by AEPSC's Human Resources department, were applied  
6 to May 2025 Base Payroll, resulting in a calculated annualized increase in payroll expense  
7 of \$506,874. The calculation to annualize payroll expense does not include overtime,  
8 severance payments, or incentive payments, which are included in adjustments W32, W29,  
9 and W30, respectively.

10 **Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR**  
11 **ADDITIONAL OVERTIME COSTS RELATED TO MERIT INCREASES (W32).**

12 A. To account for the impact of known and measurable increased base pay on the Company's  
13 overtime expense, overtime costs for the test year ended May 31, 2025 were multiplied by  
14 the approved average merit increase percentages (2.5%) for 2025. The cost-of-service  
15 increase for overtime expense related to merit increases is \$174,165.

16 **Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR MEDICARE**  
17 **TAX EXPENSE (W33).**

18 A. The Company incurs Medicare tax expense for labor costs that include base pay, overtime,  
19 and incentives. This cost-of-service adjustment for Medicare tax expense is determined by  
20 first taking the net forecasted increase related to changes in incentives (W30), annualization  
21 of base payroll (W31), merit increases (W31), and the impact of merit increases on  
22 overtime (W32). This net increase of \$3,130,903 is then multiplied by the Medicare tax  
23 rate of 1.45%, resulting in a \$45,398 increase in Company test year Medicare tax expenses.

1 **Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR SOCIAL**  
2 **SECURITY TAX EXPENSE (W34).**

3 A. The Company incurs Social Security tax expense for labor costs that include base pay,  
4 overtime, and incentives. This cost-of-service adjustment for Social Security Tax is  
5 determined by first taking the net forecasted increase of \$3,130,903 related to changes in  
6 incentives (W30), annualization of base payroll (W31), merit increases (W31), and the  
7 impact of merit increases on overtime (W32). This net increase of \$3,130,903 is then  
8 multiplied by both the percent of 2024 Company salaries subject to 2024 Social Security  
9 tax and the Social Security tax rate of 6.20%, resulting in a \$184,630 increase in Company  
10 test year Social Security taxes.

11 **Q. PLEASE DESCRIBE THE COST-OF-SERVICE ADJUSTMENT FOR SOCIAL**  
12 **SECURITY TAX BASE (W35).**

13 A. The Company incurs Social Security tax expense of 6.20% on each employee's combined  
14 base pay, overtime, and incentive compensation up to the annual Social Security tax base.  
15 The tax base on which Social Security taxes are imposed increased from \$168,600 in 2024  
16 to \$176,100 in 2025. Based on this tax base increase, the number of Company employees  
17 who earned more than \$168,600 in 2024 and the Social Security tax rate of 6.20%, a net  
18 increase in Company Social Security tax expense of \$28,133 was calculated. After  
19 applying corresponding O&M allocation factors, the cost-of-service increase due to the  
20 increase in the Social Security tax base is \$17,122.



**Depreciation and Asset Retirement Obligation Adjustments**

1   **Q.   HOW DID THE COMPANY CALCULATE THE ANNUALIZATION OF**  
2       **DEPRECIATION   EXPENSE   USING   COMMISSION-APPROVED**  
3       **DEPRECIATION RATES AS OF MAY 31, 2025 (W37)?**

4   A.   To properly reflect depreciation expense based on property balances at the end of the test  
5       year and to reflect assets placed in service or retired during the test year, I calculated a  
6       depreciation annualization adjustment by multiplying the Company's May 31, 2025, gross  
7       plant balances for each functional class by corresponding depreciation rates used in May  
8       2025. The resulting adjusted Current Annual Depreciation Expense is then compared to the  
9       corresponding 12-Month Test Year per Books Depreciation Expense, resulting in a total  
10      Company increase in depreciation expense of \$3,942,450.

11           In conjunction with calculating this adjustment, the Company excluded May 31,  
12      2025 gross plant balances and corresponding depreciation expense for investment costs  
13      recovered separately, including (1) Mitchell Plant Flue Gas Desulfurization ("FGD")  
14      investment (sponsored and explained by Company Witness Cullop), (2) North American  
15      Electric Reliability Corporation ("NERC") Compliance and Cybersecurity Cost Deferral  
16      (See Section V, Exhibit 2, W28), and (3) AROs (See Section V, Exhibit 2, W38).

17   **Q.   PLEASE DESCRIBE THE ANNUALIZATION OF ARO DEPRECIATION**  
18       **EXPENSE (W38).**

19   A.   The ARO depreciation annualization adjustment increases depreciation expense by  
20       \$113,369. The depreciation annualization adjustment is calculated by comparing  
21       annualized May 2025 ARO depreciation expense of \$1,910,405 to per books ARO  
22       depreciation expense for the test year ended May 31, 2025, of \$1,797,036 (related primarily

1 to the Company's share of Mitchell Plant AROs), resulting in a total Company ARO  
2 depreciation increase of \$113,369.

3 **Q. PLEASE DESCRIBE THE ANNUALIZATION OF ARO ACCRETION EXPENSE**  
4 **(W39).**

5 A. This adjustment increases other expense by \$124,567. This increase was calculated by  
6 comparing annualized May 2025 ARO accretion expense of \$2,193,903 to per books ARO  
7 accretion expense for the test year ended May 31, 202, of \$2,069,336 (related primarily to  
8 the Company's share of Mitchell Plant AROs), resulting in a total Company increase of  
9 \$124,567.

10 The increase in ARO accretion expense from the test year per book amount is due  
11 to: (1) additional Mitchell ARO costs as a result of the Federal EPA's revised CCR rule in  
12 2024, and (2) removing Big Sandy coal-related ARO costs. As supported by Company  
13 Witness Wolfram, the Big Sandy coal-related ARO costs were removed from the  
14 cost-of-service because they will be recovered through the Decommissioning Rider as  
15 described in the Company's August 2025 annual rider update.

16 **Q. HOW DID THE COMPANY CALCULATE THE ANNUALIZATION OF**  
17 **DEPRECIATION EXPENSE USING DEPRECIATION RATES AS**  
18 **RECOMMENDED BY THE DEPRECIATION STUDY (W48)?**

19 A. A depreciation study was completed for electric utility plant in service at March 31, 2025,  
20 as discussed and supported by Company Witness Spanos. As a result, revised depreciation  
21 rates were used to calculate a new annualized level of depreciation expense. In order to  
22 properly reflect depreciation expense based on property balances at the end of the test year,  
23 I calculated a depreciation annualization adjustment by multiplying the Company's

1 May 31, 2025, gross plant balances for each functional class by corresponding depreciation  
2 rates calculated in the depreciation study. As discussed, and supported by Company  
3 Witness Wolfram, the results of the depreciation study were not applied to the Mitchell  
4 plant balances.

5 The resulting adjusted Current Annual Depreciation Expense is then compared to  
6 the corresponding 12-Month Depreciation Expense as calculated in adjustment W37,  
7 resulting in a total Company increase in depreciation expense of \$1,167,942, in addition to  
8 what was calculated in adjustment W37.

9 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE THE**  
10 **NON-ENVIRONMENTAL PORTION OF MITCHELL PLANT NET BOOK**  
11 **VALUE FROM RATE BASE AND REMOVE THE RELATED DEPRECIATION**  
12 **EXPENSE FROM COST-OF-SERVICE (W49).**

13 A. As discussed by Company Witness Wolfram, a new rider is being proposed to recover the  
14 net book value of the non-environmental portion of the Mitchell Plant. As a result,  
15 adjustment W49 proposes to remove \$127,654,871 of Mitchell net book value from rate  
16 base and to remove annualized depreciation expense of \$8,425,896 from the  
17 cost-of-service. Upon Commission approval, Mitchell Plant depreciation expense and a  
18 pre-tax Weighted Average Cost of Capital (“WACC”) return on associated rate base would  
19 be recovered through the new rider. As supported by Company Witness Wolfram, this  
20 adjustment should not be made to the cost-of-service to the extent the Commission does  
21 not approve the separate rider recovery of the Mitchell Plant.

**Regulatory Accounting Treatment and Amortization of Regulatory Deferrals**

1   **Q.   HOW DOES THE COMPANY ACCOUNT FOR SIGNIFICANT REGULATORY**  
2       **DEFERRALS?**

3   A.   FASB ASC 980 requires deferral accounting when certain conditions are met. FASB ASC  
4       980-340 requires that when incurred costs are probable of future recovery, the unrecovered  
5       costs should be capitalized (deferred) as a regulatory asset and amortized to expense when  
6       recovered in revenues. Conversely, FASB ASC 980-405 requires the recognition of a  
7       regulatory liability/provision for refund when it becomes probable that a utility will be  
8       required by a regulator to provide a refund to customers. FASB ASC 980 recognizes that  
9       a regulator can provide reasonable assurance of the existence of an asset, if the regulator  
10      provides for the future recovery through cost-based rates of a currently incurred cost that  
11      would otherwise have been charged to expense. When that occurs, the regulator-created  
12      asset, or regulatory asset, must be recorded by deferring the incurred cost to be recovered  
13      in the future. The deferral as a regulatory asset of unrecovered incurred costs to be  
14      recovered in the future allows the Company to properly match such costs with the revenues,  
15      allowing recovery of such costs in the same accounting period. The matching of cost and  
16      revenue is a long-standing utility accounting concept, which produces meaningful financial  
17      statements especially for cost-based regulated operations. The FERC amended its Uniform  
18      System of Accounts (“USofA”), incorporating FASB ASC 980 in the USofA, in its Order  
19      390 effective January 1, 1984. As such, the Company’s proposed deferral accounting is  
20      consistent with both GAAP codified in FASB ASC 980 and the FERC USofA.

1 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO AMORTIZE THE NERC**  
2 **COMPLIANCE AND CYBERSECURITY COST DEFERRAL (W28).**

3 A. The Company continues to defer NERC Compliance and Cybersecurity costs in accordance  
4 with the Commission's final order in Case No. 2023-00159. The Company is requesting in  
5 this case to amortize the post March 31, 2023, NERC Compliance and Cybersecurity cost  
6 deferral of \$2,171,917 over five years, which represents a \$434,383 annual expense in the  
7 cost-of-service. In addition, for the NERC Compliance and Cybersecurity cost deferral  
8 related to the period April 1, 2020, through March 31, 2023, the Company is requesting to  
9 continue the level of annual amortization expense authorized in Case No. 2023-00159 of  
10 \$431,505. The cost-of-service adjustment at Section V, Exhibit 2, W28 is increasing  
11 expense in the test year by \$465,475 to adjust the test year per book expense amount of  
12 \$400,413 to the requested annual expense amount of \$865,889 (composed of \$434,383  
13 related to amortization of the deferral post March 31, 2023, and \$431,505 related to the  
14 amortization of the deferral for the period April 1, 2020, through March 31, 2023). The  
15 five-year amortization period proposed in this case is consistent with the amortization  
16 period authorized in prior cases, and it aligns with the five-year depreciable life of  
17 underlying projects.

18 **Q. PLEASE EXPLAIN THE PENSION SETTLEMENT ACCOUNTING THAT WAS**  
19 **TRIGGERED BY THE 2024 VOLUNTARY SEVERANCE PROGRAM.**

20 A. In April 2024, American Electric Power Corporation, Inc. ("AEP") and its subsidiaries,  
21 including Kentucky Power, announced a voluntary severance program designed to achieve  
22 a reduction in the size of AEP's workforce and help offset increasing operation and  
23 maintenance expenses caused by inflation. Some Kentucky Power employees requested to

1 take the voluntary severance package, and substantially all of those employees were  
2 approved to terminate employment in July 2024. Many of those employees also chose to  
3 take lump-sum payments from the AEP qualified pension plan in 2024, causing  
4 year-to-date lump-sum pension plan payments to exceed the applicable plan threshold in  
5 November 2024. AEP and its subsidiaries, including Kentucky Power, thus triggered  
6 Pension Settlement Accounting and recorded pension settlement accounting entries in the  
7 fourth quarter of 2024.

8 Pension settlement accounting does not change the overall cost of the pension  
9 benefit plan; rather, it simply results in a change in the timing of expense recognition  
10 required by GAAP. For ratemaking purposes, a normalized level of net pension expense  
11 recognized under GAAP is included in base rate cost-of-service. Accelerated expense of  
12 \$1,689,276 associated with 2024 pension settlement accounting (“2024 Pension Settlement  
13 Amount”) is not in the normalized level of net pension expense reflected in Kentucky  
14 Power’s requested base rate cost-of-service for ratemaking purposes, due to the atypical  
15 and infrequent nature of a change in expense timing resulting from the pension settlement.  
16 In order to permit Kentucky Power an opportunity to recover the direct expense associated  
17 with its pension benefit plan, including the 2024 Pension Settlement Amount, the Company  
18 is requesting approval to defer the 2024 Pension Settlement Amount to a regulatory asset.  
19 The Company further requests authorization to amortize the 2024 Pension Settlement  
20 Amount regulatory asset and include related amortization expense in rates over 12 years  
21 (the average remaining service period of the pension plan participants), in the same manner  
22 expense would have been included in ratemaking had the pension settlement accounting  
23 not been triggered in 2024.

1 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO DEFER AND AMORTIZE THE**  
2 **DIRECT PENSION SETTLEMENT COSTS (W47).**

3 A. The Company is requesting to defer and amortize the direct pension settlement expense of  
4 \$1,689,276 incurred in 2024, over 12 years, which represents a \$140,773 increase in annual  
5 expense in the cost-of-service.

**Other O&M Adjustments**

6 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE JOINT USE POLE**  
7 **RENTAL REVENUE AND O&M EXPENSE ACTIVITY RELATED TO A PRIOR**  
8 **PERIOD (W17).**

9 A. An adjustment to joint use pole rental revenue and expense was recorded in the test year  
10 that relates to a prior period. This cost-of-service adjustment decreases test year revenue  
11 and increases test year expense to remove this prior period adjustment from the test year.  
12 The revenue (Account 454) decrease and O&M expense (Account 589) increase is  
13 \$271,394 and \$21,148, respectively.

14 **Q. PLEASE EXPLAIN THE ADJUSTMENT FOR INTEREST EXPENSE**  
15 **ASSOCIATED WITH CUSTOMER DEPOSITS (W20).**

16 A. Test year customer deposit interest expense was \$1,839,862. During 2024, the interest rate  
17 paid by Kentucky Power pursuant to KRS 278.460 on customer deposits was 5.38%. On  
18 December 3, 2024, the Commission announced that the 2025 interest rate applicable to  
19 customer deposits would be decreased to 4.19%. Consistent with the treatment of customer  
20 deposit interest expense in prior base rate cases, Kentucky Power proposes to decrease test  
21 year customer deposit interest expense by \$243,879 to \$1,595,983 in order to reflect the  
22 decrease in the applicable rate from 5.38% to 4.19%.

1 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO ANNUALIZE LEASE EXPENSE**  
2 **(W25).**

3 A. This adjustment increases O&M expense to reflect the annualized lease expense for the  
4 Company at the test year end. Specifically, annualized May 2025 lease expenses of  
5 \$304,154 were compared to test year lease expenses of \$187,211, resulting in a calculated  
6 increase of \$116,943.

7 **Q. PLEASE EXPLAIN THE AFUDC OFFSET ADJUSTMENT (W41).**

8 A. The May 31, 2025, balance of Construction Work in Progress (“CWIP”) was used in the  
9 determination of rate base. Consistent with prior Commission practice for the Company,  
10 an Allowance for Funds Used During Construction (“AFUDC”) “offset” adjustment is  
11 being made to record AFUDC above the line. The CWIP balance was \$166,213,540 on  
12 May 31, 2025, of which \$36,255,526 is not subject to AFUDC. The remaining balance of  
13 \$129,958,014 is subject to AFUDC. Using the requested overall return of 7.574%,  
14 annualized AFUDC is \$9,843,020. The AFUDC booked during the test year was  
15 \$5,902,570 requiring an adjustment to increase the AFUDC offset by \$3,940,450.

16 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE PENSION SETTLEMENT**  
17 **EXPENSE (W46).**

18 A. As described above, pension settlement accounting was triggered during 2024 as a result  
19 of the Voluntary Severance Program. As a result, Kentucky Power recorded expense in the  
20 test year that is atypical and infrequent in nature. This cost-of-service adjustment decreases  
21 test year expense to remove the impact of this entry from the test year. The O&M expense  
22 (Account 926) decrease is \$1,689,276.



## 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
Cash Working Capital	W56
Remove NERC Compliance and Cybersecurity Net Plant from Rate Base	W58

**Q. PLEASE DESCRIBE THE ALLOWANCE FOR CASH WORKING CAPITAL  
ADJUSTMENT INCLUDED IN THE COMPANY'S RATE BASE (W56).**

A. This adjustment calculates a Cash Working Capital ("CWC") allowance of \$60,772,165 for the test year ended May 31, 2025, which decreases the Company's rate base and resulting revenue requirement. The expense lead and revenue lag days used in the computation of this adjustment were provided to me by Company Witness Lyons, the sponsor of Kentucky Power's lead-lag study. The net lead-lag days from the lead-lag study are multiplied by the pro forma 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 Lyons. The result is the Kentucky retail jurisdiction CWC allowance reflected by the Company in this filing.

1 **Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE NERC COMPLIANCE**  
2 **AND CYBERSECURITY INVESTMENT FROM RATE BASE (W58).**

3 A. Beginning with Case No. 2014-00589, the Commission approved the deferral of certain  
4 NERC Compliance and Cybersecurity costs. Because the related intangible plant  
5 investment is earning a WACC return through the approved deferral mechanism, the  
6 Company is removing the related net intangible plant balance of \$341,158 as of May 31,  
7 2025, from rate base.<sup>4</sup>

**VII. CAPITALIZATION ADJUSTMENTS**

8 **Q. ARE YOU SPONSORING ANY ADJUSTMENTS TO THE COMPANY'S**  
9 **CAPITALIZATION CALCULATION?**

10 A. Yes. The table below identifies the adjustments to the Company's capitalization calculation  
11 that I am sponsoring. The details supporting the calculations of these adjustments are  
12 included on the referenced pages of Exhibit 2 to Section V of the Application. I provided  
13 these adjustments to Company Witness Cost to incorporate in Section V, Schedule 3,  
14 Kentucky Power Company Capitalization for the test year ended May 31, 2025. As  
15 discussed by Company Witness Cost, capitalization is being presented on Section V,  
16 Schedule 3 for informational purposes only, as rate base is being used to compute the  
17 Company's revenue requirement pursuant to the Commission's order in Case  
18 No. 2020-00174.

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<sup>4</sup> The related NERC Compliance and Cybersecurity Regulatory Assets were excluded from per books rate base; therefore, it was not necessary to propose a pro forma adjustment to remove these regulatory assets from rate base.

Adjustment Description	Reference in Section V, Exhibit 2
Remove NERC Compliance and Cybersecurity Investment from Capitalization	W58

**Q. PLEASE EXPLAIN THE ADJUSTMENT TO REMOVE NERC COMPLIANCE AND CYBERSECURITY INVESTMENT FROM CAPITALIZATION (W58 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, Exhibit 2, W58, I provided Company Witness Cost with an adjustment to capitalization of \$2,950,021 to reflect the Company's related net intangible plant investment balance of \$341,158 and regulatory asset balance of \$3,393,046 as of May 31, 2025, net of related accumulated deferred income taxes of \$784,183.

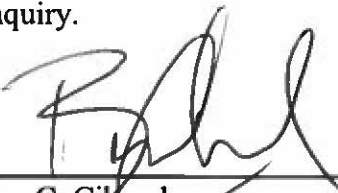
#### **VIII. CONCLUSION**

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

## VERIFICATION

The undersigned, Brian C. Ciborek, being duly sworn, deposes and says he is the Accounting Senior 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.

  
\_\_\_\_\_  
Brian C. Ciborek

Franklin )  
Ohio )

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian C. Ciborek, on August 25, 2025.

  
\_\_\_\_\_  
Notary Public



My Commission Expires Never.

Notary ID Number -

**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 Certain Regulatory And Accounting     )  
Treatments; and (4) All Other Required Approvals     )  
And Relief                                                         )

Case No. 2025-00257

**DIRECT TESTIMONY OF**  
**DAVID HODGSON**  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
DAVID HODGSON ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT DAH-1	IRS Private Letter Ruling 105951-22
EXHIBIT DAH-2	IRS Private Letter Ruling 105952-22
EXHIBIT DAH-3	IRS Private Letter Ruling 107770-22

**DIRECT TESTIMONY OF  
DAVID HODGSON ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is David Hodgson. I am the Managing Director Tax Accounting & Regulatory  
3       for American Electric Power Service Corporation (“AEPSC”), a wholly owned subsidiary  
4       of American Electric Power, Inc. (“AEP”). AEP is the parent company of Kentucky Power  
5       Company (“Kentucky Power” or the “Company”). My business address is 1 Riverside  
6       Plaza, Columbus, Ohio 43215.

**II. BACKGROUND**

7   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
8       **BUSINESS EXPERIENCES.**

9   A.   I graduated from The Ohio State University with a Bachelor of Science in Business  
10       Administration with a specialization in Accounting. In 2000, I accepted a position with  
11       AEPSC as a Tax Analyst V. I was promoted to positions from Tax Analyst IV to Tax  
12       Analyst I over the course of 2002–2009. In 2011, I was promoted to Sr. Tax Analyst and  
13       later that year to Tax Project Manager and in 2013 to Tax Manager. I was promoted to Tax  
14       Accounting & Regulatory Support Manager in 2019, and in 2021 I was promoted to  
15       Director Tax Accounting & Regulatory. In 2024, I was promoted to my current position as  
16       Managing Director Tax Accounting & Regulatory.

1 **Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY WITH AEPSC?**

2 A. As Managing Director Tax Accounting & Regulatory, I am responsible for managing and  
3 developing federal and state tax data provided by the AEPSC Tax Department to support  
4 regulatory proceedings. This work includes designing and managing regulatory tax policies  
5 and practices, providing expert witness testimony on tax matters and their regulatory  
6 impacts, as well as overseeing the tax expert witness testimony of other individuals. I am  
7 also responsible for the review of tax accounting entries and records to support the financial  
8 reporting of AEP and its subsidiaries.

9 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
10 **PROCEEDINGS?**

11 A. Yes. I have previously provided testimony before the Federal Energy Regulatory  
12 Commission, the Arkansas Public Service Commission, the Indiana Utility Regulatory  
13 Commission, the Louisiana Public Service Commission, the Michigan Public Service  
14 Commission, the Public Utility Commission of Ohio, the Oklahoma Corporation  
15 Commission, the Public Utility Commission of Texas, the Virginia State Corporation  
16 Commission, and the Public Service Commission of West Virginia.

### **III. PURPOSE OF TESTIMONY**

17 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
18 **PROCEEDING?**

19 A. The purpose of my Direct Testimony in this proceeding is: (1) to calculate the Gross  
20 Revenue Conversion Factor ("GRCF"); (2) to present and support certain adjustments to  
21 the jurisdiction federal, state, and local income taxes to which Kentucky Power is subject;  
22 (3) to support the tax effects of certain fixed, known, and measurable ratemaking



1 adjustments for the test year ended May 31, 2025; and (4) to support certain modifications  
2 to the Company's existing Federal Tax Cut Tariff ("Tariff F.T.C.") to align the  
3 amortization of protected excess deferred income taxes with the test-year amortization and  
4 to adjust the test year amortization related to the net operating loss carryforward deferred  
5 tax asset.

6 **Q. ARE YOU SPONSORING ANY EXHIBITS?**

7 A. Yes. I am sponsoring certain portions of the following Schedules and Workpapers:

- 8 • Section V, Exhibit 2 (certain portions)
- 9 • Section V, Exhibit 3
- 10 • Section V, Exhibit 3, Workpaper S-2

11 I am also sponsoring Exhibit DAH-1, Exhibit DAH-2, and Exhibit DAH-3. These exhibits  
12 are private letter rulings ("PLRs") issued by the Internal Revenue Service ("IRS") to  
13 affiliates of the Company, which I will discuss later in my Direct Testimony.

14 **Q. WHAT ARE THE IMPACTS OF THE COMPANY'S TAX ADJUSTMENTS IN**  
15 **BASE RATES IN THIS PROCEEDING?**

16 A. Figure DAH-1 below summarizes the proposed impacts addressed in my Direct Testimony.

**Figure DAH-1**

<b>Adjustment</b>	<b>Expense or Rate Base</b>	<b>Rate Base Gross Amount Increase / (Decrease)</b>	<b>After Tax Rate of Return</b>	<b>Amount Increase / (Decrease) in Net Income</b>	<b>Section V Reference</b>
Annualization of Property Taxes	Expense	N/A	N/A	\$4,262,813	Exhibit 2, W42
State Business and Occupation Tax	Expense	N/A	N/A	\$1,190,525	Exhibit 2, W44
Interest Synchronization	Expense	N/A	N/A	\$2,963,770	Exhibit 3
Net Operating Loss Carryforward – Deferred Tax Asset	Rate Base	\$44,950,166	7.57%	\$3,402,728	Exhibit 3
Net Operating Loss Carryforward – Regulatory Liability	Rate Base	\$9,675,296	7.57%	\$732,420	Exhibit 3

**Q. WHAT ARE THE AMOUNTS PROPOSED TO BE INCLUDED IN THE REVISED TARIFF F.T.C.?**

A. Figure DAH-2 below summarizes the proposals that will be included in the Tariff F.T.C., which I will discuss further below.

**Figure DAH-2**

<b>Adjustment</b>	<b>Expense or Rate Base</b>	<b>Rate Base Gross Amount Increase / (Decrease)</b>	<b>After Tax Rate of Return</b>	<b>Amount Increase / (Decrease) in Net Income</b>
Excess Protected Amortization	Expense	N/A	N/A	(\$1,410,730)

#### **IV. GROSS REVENUE CONVERSION FACTOR**

**Q. PLEASE DESCRIBE THE GRCF.**

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.

1   **Q.   HOW WAS THE GRCF RATE DETERMINED?**

2   A.   The uncollectible accounts rate and the KRS 278.130 assessment rate were provided to me  
3       by Kentucky Power; the state and federal income tax rates and apportionment factors are  
4       based on the most recent income tax return information that also is currently being used in  
5       the monthly closing accrual process. Please see Section V, Exhibit 3, Workpaper S-2,  
6       Page 2. The methodology used in this case was also utilized in the Company's prior base  
7       rate cases.

**V. JURISDICTIONAL STATE AND FEDERAL INCOME TAXES**

8   **Q.   PLEASE DESCRIBE THE COMPUTATION OF JURISDICTIONAL STATE AND**  
9       **CURRENT FEDERAL INCOME TAXES.**

10   A.   The computation of jurisdictional current federal income tax is accomplished by first  
11       allocating pre-tax book income and the various book-to-tax adjustments used in the  
12       determination of the Company's total federal taxable income to Kentucky Power's retail  
13       customers and applying the statutory federal income tax rate of 21% as shown in Section  
14       V, Exhibit 3. The computation of jurisdictional deferred federal income tax is  
15       accomplished by applying the appropriate federal income tax rate to the allocated  
16       normalized timing differences, as shown in Section V, Exhibit 3, and by amortizing the  
17       allocated balances of the excess deferred income taxes using the average rate assumption  
18       method ("ARAM"). State income tax expense is calculated on the same basis as the federal  
19       income tax expense as shown in Section V, Exhibit 3. Company Witness Cost prepared the  
20       jurisdictional allocation factors upon which I relied. Each component was allocated to the  
21       Kentucky retail jurisdiction as shown in Section V, Exhibit 3 by multiplying the applicable  
22       jurisdictional allocation factor.

## **VI. RATEMAKING ADJUSTMENTS**

**Q. WHAT 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 (W42);
2. State Business and Occupation Tax (W44);
3. Removing Kentucky excess accumulated deferred income tax ("Excess ADIT") amortization related to Tariff F.T.C. (W53);
4. Interest Synchronization Adjustment (W54); and
5. Net Operating Loss Carryforward Deferred Tax Asset and Adjustment to Excess Protected Amortization (W55).

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, Exhibit 2.

### **Annualization of Property Tax (Section V, Exhibit 2, W42)**

**Q. PLEASE DESCRIBE THE ANNUALIZATION OF PROPERTY TAX ADJUSTMENT (W42).**

A. Adjustment W42 of Section V, Exhibit 2 calculates the difference between the property taxes that were actually paid through May 31, 2025 (\$11.2) million and what the Company expects to pay through year end (\$15.4) million. The adjustment to increase property tax expense by \$4.2 million removes the impact of favorable out-of-period activity recorded

1 during the test year and more accurately aligns the property tax expense in the  
2 cost-of-service with the rate base at the end of the test year.

**State Business and Occupation Tax**  
**(Section V, Exhibit 2, W44)**

3 **Q. PLEASE DESCRIBE THE STATE BUSINESS AND OCCUPATION TAX**  
4 **ADJUSTMENT (W44).**

5 A. Adjustment W44 of Section V, Exhibit 2 adjusts the state business and occupation tax  
6 expense to remove an out-of-period adjustment that was recorded during the test period.  
7 The out-of-period adjustment reflects the \$1.2 million accrual for tax refunds that were  
8 received during the test year for tax years prior to the test year; thus, it is appropriately  
9 adjusted out of the test year.

**Removal of Kentucky Excess ADIT Amortization Related to Tariff F.T.C.**  
**(Section V, Exhibit 2, W53)**

10 **Q. PLEASE DESCRIBE THE ADJUSTMENT RELATED TO THE AMORTIZATION**  
11 **OF EXCESS ADIT IN THIS PROCEEDING (W53).**

12 A. The Company is proposing to continue to include the amortization of protected Excess  
13 ADIT in Tariff F.T.C as approved in Case No. 2020-00174. Adjustment 53 of Section V,  
14 Exhibit 2 removes Kentucky protected Excess ADIT amortization related to the Tariff  
15 F.T.C. The test period included all Excess ADIT amortization for Kentucky Power that is  
16 included in other jurisdictions and/or in other rates that are not associated with base rates  
17 proposed in this case. These amounts were removed from the tax expense included in this  
18 case by applying a “Non-Allocated” factor of 0%.

1   **Q.   WHAT ARE EXCESS ACCUMULATED DEFERRED INCOME TAXES?**

2   A.   Excess ADIT arises due to temporary differences such as the accelerated depreciation  
3       provisions of the Internal Revenue Code that can result in corporations, such as Kentucky  
4       Power, recovering through rates their federal corporate income tax expense at a different  
5       (initially faster) rate than they pay the associated taxes. Upon remeasurement of ADIT  
6       following the passage of the Tax Cuts and Jobs Act (“TCJA”), the Company, as a regulated  
7       utility following Financial Accounting Standards Board Accounting Standards  
8       Codification 980, deferred this difference on the Company’s books as a regulatory liability.  
9       If income tax rates had remained the same, the deferral would have been reversed in later  
10      years as the Company paid its current federal corporate income tax expense at a rate that  
11      was greater than the Company was recovering through rates. When the federal corporate  
12      tax rate is reduced, as happened with the TCJA, and all other things being equal, a portion  
13      of the deferral will never be paid by the Company and thus becomes “excess.”

14   **Q.   WHAT ARE PROTECTED EXCESS ACCUMULATED DEFERRED INCOME**  
15   **TAXES?**

16   A.   Protected Excess ADIT is related only to temporary differences that arise due to differences  
17      in the method and life used in calculating depreciation for tax purposes and for book  
18      purposes. The TCJA requires that protected Excess ADIT be amortized over “the  
19      remaining lives of the property as used in its regulated books of account which gave rise  
20      to the reserve for deferred taxes.” *See* TCJA Subtitle C, Part I, Sec. 13001(d)(3)(B). For  
21      Kentucky Power, this amortization period is based on the ARAM.

1   **Q.   PLEASE DESCRIBE THE ARAM.**

2   A.   The ARAM reduces the Excess ADIT over the remaining regulatory lives of the property  
3       that gave rise to the reserve for deferred taxes during the years in which the deferred tax  
4       reserve related to such property is reversing. That is, when the tax depreciation for a given  
5       asset becomes less than the book depreciation, the excess tax reserve is reduced by the  
6       difference between the taxes required under the old 35% rates (and other rates prior to  
7       1993) and the taxes required under the new 21% rate. The Excess ADIT is not reduced  
8       until, and then only to the degree, that tax benefits for a given asset expire. The ARAM  
9       provides that the utility will not have to refund excess taxes to customers any faster than it  
10      would have had to pay those taxes to the federal government had the tax rates not been  
11      reduced.

**Interest Synchronization Adjustment**  
**(Section V, Exhibit 2, W54)**

12   **Q.   PLEASE DESCRIBE THE INTEREST SYNCHRONIZATION ADJUSTMENT**  
13       **(W54).**

14   A.   Adjustment 54 of Section V, Exhibit 2 synchronizes the capital costs and capital structure  
15       included by the Company in this filing with the federal and state income taxes included in  
16       the test period cost-of-service and the interest expense tax deduction that will result. The  
17       adjustment resulted in an increase to state income tax of \$594,911 and an increase to federal  
18       income tax of \$2,368,858 for a total pro forma increase to income tax expense of  
19       \$2,963,770.

**Stand-Alone Net Operating Loss Carryforward**  
**(Section V, Exhibit 2, W55)**

1    **Q.    WHAT IS A NET OPERATING LOSS CARRYFORWARD?**

2    A.    A net operating loss (“NOL”) occurs when, in a given year, a taxpayer has more deductions  
3            than taxable income. When an NOL occurs, the Internal Revenue Code allows the taxpayer  
4            to carry the NOL forward (“NOL Carryforward,” or “NOLC”) to subsequent years and  
5            offset otherwise taxable income produced in that future year. This carryforward is recorded  
6            as a deferred tax asset (“NOLC DTA”) for accounting purposes to reflect the future  
7            reduction to taxes payable.

8    **Q.    WHAT IS THE COMPANY PROPOSING IN THIS CASE WITH RESPECT TO A**  
9            **NET OPERATING LOSS CARRYFORWARD?**

10   A.    The Company’s requested revenue requirement in this case includes adjustments to account  
11            for an NOLC on a stand-alone basis based on the balance as of the end of the test year.  
12            Including a NOLC on a stand-alone basis in the calculation of ADIT and Excess ADIT is  
13            necessary to comply with the requirements of section 168(i)(9) of the Internal Revenue  
14            Code, Treasury Regulation § 1.167(l)-1(h), and section 13001 of the TCJA  
15            (“Normalization Rules”).

16   **Q.    PLEASE DISCUSS THE PRO FORMA ADJUSTMENTS MADE TO ACCOUNT**  
17            **FOR AN NOLC ON A STAND-ALONE BASIS (W55).**

18   A.    A pro forma adjustment of \$44,950,166 is being made, which reduces the ADIT balance  
19            to include a NOLC DTA calculated on a stand-alone basis thereby increasing the rate base  
20            as reflected in Figure DAH-1 and Section V, Exhibit 3. This adjustment represents the  
21            amount of ADIT associated with accelerated tax depreciation for which the Company has  
22            not received an interest-free loan from the federal government. This adjustment reflects the



1 ADIT associated with the taxable losses the Company has generated in excess of the  
2 taxable income it has generated and been able to offset based on the NOLC and carryback  
3 provisions of the Internal Revenue Code.

4 A pro forma adjustment of \$ 9,675,296 is also being made which reduces the Excess  
5 ADIT balance to account for a NOLC DTA calculated on a stand-alone basis. This  
6 adjustment takes into account the NOLC DTA in the calculation of Excess ADIT available  
7 to be amortized thereby increasing the rate base as reflected in Figure DAH-1 and Section  
8 V, Exhibit 3.

9 **Q. DOES THE ADJUSTMENT MADE TO EXCESS ADIT FOR THE NOLC IMPACT**  
10 **THE AMORTIZATION OF PROTECTED EXCESS ADIT TO BE INCLUDED IN**  
11 **TARIFF F.T.C.?**

12 A. Yes. The pro forma adjustment to take into account the NOLC DTA in the calculation of  
13 Excess ADIT reduces the amount available to be amortized. The amortization of protected  
14 Excess ADIT includes a reduction of \$413,561 to account for the NOLC.

15 **Q. HAS THE COMPANY PREVIOUSLY REQUESTED RATE MAKING WHICH**  
16 **ACCOUNTS FOR A NOLC ON A STAND-ALONE BASIS?**

17 A. Yes. The Company requested rate making which accounts for a NOLC on a stand-alone  
18 basis in its previous base rate case, Case No. 2023-00159 before the Public Service  
19 Commission of Kentucky ("Commission").

20 **Q. WHAT DID THE COMMISSION ORDER WITH RESPECT TO THE NOLC DTA**  
21 **IN CASE NO. 2023-00159?**

22 A. In Case No. 2023-00159, the Commission deferred any recovery on the NOLC DTA until  
23 Kentucky Power received a PLR from the IRS affirming the Company's analysis that it

1 would be a violation of the Normalization Rules for it to be excluded from rate making.  
2 Specifically, the Commission order in Case No. 2023-00159 stated the following with  
3 respect to the NOLC DTA, and ruled similarly with respect to the NOLC Excess ADIT:

4 In the Settlement, the parties agreed that a return on the NOLC  
5 ADIT will be excluded from the base rate revenue requirement. That  
6 amount would be deferred as a regulatory asset until base rates  
7 including the stand-alone NOLC are effective in a future base rate  
8 case. Kentucky Power will not accrue a carrying charge on the  
9 NOLC regulatory asset or the NOLC regulatory liability. Recovery  
10 of the regulatory asset would be contingent on Kentucky Power  
11 receiving a PLR from the IRS that affirms Kentucky Power's  
12 position regarding the NOLC ADIT. If the PLR indicates it is a  
13 normalization violation, Kentucky Power will reverse the NOLC  
14 regulatory liability and recover the NOLC regulatory asset, and the  
15 NOLC deficient taxes over a three-year period through base rates  
16 established in the first base rate case filed after the private letter  
17 ruling from the IRS is received.

18 The Commission finds that it is reasonable to exclude the  
19 NOLC ADIT from rate base and defer amortization of the NOLC  
20 ADIT to a regulatory asset with recovery contingent on Kentucky  
21 Power receiving a PLR that affirms its position regarding the NOLC  
22 ADIT.

23 **Q. HAS THE COMPANY RECEIVED A PLR FROM THE IRS AS DISCUSSED IN**  
24 **THE COMMISSION ORDER IN CASE NO. 2023-00159?**

25 A. While Kentucky Power did file a request for a PLR from the IRS on August 13, 2024, at  
26 this time, it has not received a ruling. However, since the conclusion of Case  
27 No. 2023-00159, there has been substantial new evidence that supports the Company's  
28 position that it would be a violation of the Normalization Rules for the Company's NOLC  
29 adjustments to be excluded.

1   **Q.   WHAT IS THIS SUBSTANTIAL NEW EVIDENCE?**

2   A.   On April 2, 2024, the IRS transmitted PLRs to three affiliates of Kentucky Power  
3       (“Affiliate Companies”) in response to those affiliates requesting a ruling regarding the  
4       treatment of an NOLC in ratemaking.

5           The Affiliate Companies requested the IRS ruling on four key items. First, the  
6       Affiliate Companies requested that the IRS rule whether the reduction of the stand-alone  
7       NOLC DTA in rate base would violate the Normalization Rules. Second, the Affiliate  
8       Companies requested that the IRS rule whether reducing the used and useful public utility  
9       property includible in rate base, treating payments received through the tax allocation  
10      agreement as zero-cost capital, or eliminating the NOLC DTA to reflect the tax allocation  
11      agreement payments would violate the Normalization Rules. Third, the Affiliate  
12      Companies requested that the IRS rule the Excess ADIT available to be amortized must  
13      include the stand-alone NOLC Excess ADIT to comply with the normalization  
14      requirements of the TCJA. Finally, the Affiliate Companies requested the IRS rule as to  
15      whether any ratemaking treatments proposed by parties which reduced the stand-alone  
16      NOLC DTA would result in a normalization violation and preclude the Affiliate  
17      Companies from the ability to claim accelerated tax depreciation.

18   **Q.   PLEASE SUMMARIZE THE RULINGS ISSUED BY THE IRS.**

19   A.   In short, the IRS ruled that a reduction to the stand-alone NOLC DTA in rate base, the  
20      exclusion of the NOLC Excess ADIT from the calculation of Excess ADIT available to  
21      amortize, reducing the used and useful public utility property in rate base equal to the tax  
22      allocation agreement payments, or treating the tax allocation agreement payments as  
23      zero-cost capital would result in a violation of the Normalization Rules. Such a violation

1 would result in the loss of the Affiliate Companies' ability to claim accelerated  
2 depreciation.

3 On the first ruling requested, the IRS ruled that a reduction to the stand-alone  
4 NOLC DTA would violate the deferred tax reserve computational rules of  
5 § 1.167(l)-1(h)(2). On the second ruling requested, the IRS ruled that putting into effect a  
6 rate order reducing the used and useful public utility property includible in rate base in an  
7 amount equal to the tax allocation agreement payments, treating the tax allocation  
8 agreement payments as zero-cost capital, or eliminating the NOLC DTA to reflect the tax  
9 allocation agreement payments would violate the consistency rules of § 168(i)(9)(B). On  
10 the third ruling requested, the IRS ruled that it would violate the requirements of the TCJA  
11 § 13001 to exclude the NOLC DTA as a reduction to the total Excess ADIT available to  
12 be amortized. On the Affiliate Companies' last ruling request, the IRS ruled that  
13 implementation of any ratemaking that reduced the NOLC DTA would result in a  
14 normalization violation which results in the loss of accelerated depreciation. The IRS also  
15 ruled that, under the facts of this case as presented, disallowance of the Affiliate  
16 Companies' right to claim accelerated depreciation would not occur. Those PLRs are  
17 attached to my Direct Testimony as Exhibit DAH-1, Exhibit DAH-2, and Exhibit DAH-3.

18 **Q. WHAT IMPACT WOULD A NORMALIZATION VIOLATION HAVE ON**  
19 **CUSTOMERS?**

20 A. A normalization violation would result in higher utility rates for customers. A  
21 normalization violation would prevent the Company from claiming deductions for  
22 accelerated depreciation and would result in the Company paying the IRS more rapidly for  
23 its previously deferred taxes. This would result in a lower ADIT balance, which would

1 cause the rate base for the Company to increase. As customers pay a return on rate base,  
2 any increase in rate base would directly result in higher rates. This lower ADIT would also  
3 represent the reduction to a cost-free source of capital for the Company.

**VII. NOLC REGULATORY ASSET**

4 **Q. IN CASE NO. 2023-00159, DID THE COMMISSION AUTHORIZE THE**  
5 **ACCRUAL OF A REGULATORY ASSET WITH RESPECT TO THE NOLC?**

6 A. Yes. As stated earlier in my Direct Testimony, the Commission deferred any recovery on  
7 the NOLC DTA until Kentucky Power received a PLR from the IRS affirming the  
8 Company's analysis of the relevant tax law. The Commission order in that case stated that  
9 the base rate revenue requirement related to the NOLC DTA in that case would be deferred  
10 as a regulatory asset ("NOLC Regulatory Asset").

11 **Q. IS THE COMPANY SEEKING RECOVERY IN THIS CASE OF THE**  
12 **REGULATORY ASSET THAT THE COMMISSION AUTHORIZED RELATED**  
13 **TO THE NOLC?**

14 A. No. The Commission order in Case No. 2023-00159 stated that recovery of NOLC  
15 Regulatory Asset would be contingent on Kentucky Power receiving a PLR from the IRS  
16 affirming the Company's analysis. While Kentucky Power has filed a request to the IRS  
17 for a PLR, at this time, it has not received a ruling.

18 **Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE NOLC**  
19 **REGULATORY ASSET?**

20 A. As discussed in the Direct Testimony of Company Witness Wolffram, the Company is  
21 proposing that if the IRS issues a PLR to Kentucky Power, which affirms the Company's

1 position on the NOLC, the NOLC Regulatory Asset should be recovered through Tariff  
2 F.T.C.

3 **Q. WHY IS THE COMPANY PROPOSING TO RECOVER THE NOLC**  
4 **REGULATORY ASSET THROUGH TARIFF F.T.C. RATHER THAN WAITING**  
5 **TO RECOVER THROUGH ITS NEXT BASE RATE CASE?**

6 A. Including the recovery of the NOLC Regulatory Asset through Tariff F.T.C. provides for  
7 a timelier correction of the normalization violation. In each of the three Affiliate  
8 Companies' PLRs, the IRS stated that it would not assert that the past failure to follow the  
9 Normalization Rules constituted a normalization violation and that it would not apply the  
10 sanction of denial of accelerated depreciation to the utility. The IRS stated that it would  
11 not do so in part because of the assertion that was made in the PLR request that corrective  
12 actions would be taken at the earliest available opportunity. Including the amounts in Tariff  
13 F.T.C. would ensure that corrective action is being addressed at the earliest available  
14 opportunity rather than wait for the next base rate case at an indetermined time in the future;  
15 therefore, avoiding potential sanctions that could further increase costs to customers.

#### **VIII. CONCLUSION**

16 **Q. OVERALL, WHAT ARE THE BENEFITS TO CUSTOMERS ASSOCIATED**  
17 **WITH THE COMPANY'S PROPOSED TAX TREATMENTS DESCRIBED IN**  
18 **YOUR DIRECT TESTIMONY?**

19 A. The Company's proposed tax treatments ensure that the Company properly recovers tax  
20 expenses through rates that are equivalent to those incurred. The proposals also ensure that  
21 the Company complies with the Normalization Rules and therefore protects customers  
22 from the negative consequences that would occur if it did not.

1    **Q.     DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2    A.     Yes, it does.

# VERIFICATION

The undersigned, David A. Hodgson, being duly sworn, deposes and says he is the Managing Director, Tax Accounting and Regulatory 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.

David A Hodgson  
David A. Hodgson

State of Ohio )  
 ) Case No 2025-00257  
County of Franklin )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by David A. Hodgson, on August 18, 2025

Pauline A Lutz  
Notary Public

Pauline A Lutz  
NOTARY PUBLIC  
State of Ohio  
My Commission Expires 9/12/2026

My Commission Expires \_\_\_\_\_

Notary ID Number 2016-RE-600919



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INTERNAL REVENUE SERVICE



FAX TRANSMISSION  
Cover Sheet

Date: April 03, 2024

To: Vice President of Tax

Address/Organization:

Fax Number: (614) 716-2777 Office Number:

From: Martha M. Garcia

Address/Organization: CC:PSI:B6

Fax Number: Office Number: (202) 317-6853

Number of pages: 32 Including cover page

Subject: PLR-105951-22

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**Internal Revenue Service**

**Department of the Treasury**  
Washington, DC 20224

Index Number: 168.24-01

Third Party Communication:  
Date of Communication: N/A

Vice President – Tax  
American Electric Power Company Inc.  
1 Riverside Plaza  
Columbus, OH 43215  
FAX: (614) 716-2777

Person To Contact:  
Martha M. Garcia, ID No. 0630922  
Telephone Number:  
(202) 317-6853  
Refer Reply To:  
CC:PSI:B6  
PLR-105951-22  
Date:  
March 8, 2024

**Legend:**

Parent	=	American Electric Power Company, Inc. (AEP) E.I.N. 13-4922640
Taxpayer	=	Southwestern Electric Power Company (SWEPCO) E.I.N. 72-0323455
Additional Subsidiary	=	Public Service Company of Oklahoma E.I.N. 73-0410895
Date 1	=	March 11, 2022
Date 2	=	April 11, 2022
Date 3	=	June 2, 2022
Date 4	=	June 1, 2022
Date 5	=	August 26, 2022
Date 6	=	December 31, 2019
Date 7	=	December 31, 2020
Date 8	=	November 18, 2021
Date 9	=	January 13, 2022
Date 10	=	March 31, 2020
Commission A	=	Public Utility Commission of Texas
Commission B	=	Federal Energy Regulatory Commission (FERC)
Staff	=	Staff of Commission A
<u>a</u>	=	5.5 million
<u>b</u>	=	11
<u>c</u>	=	500,000
<u>d</u>	=	3
<u>e</u>	=	455,122,490
<u>f</u>	=	45 million
<u>g</u>	=	194,453,551
Year 1	=	2009
State	=	Texas
System	=	Uniform System of Accounts

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Form	=	Form 3Q
Form A	=	Form 1
Form B	=	Form 3
Rules	=	Electric Substantive Rules
Enforcement Matter	=	AI93-5-000
Agency	=	SEC
Opinion	=	Opinion No. 173

Dear Vice President of Tax:

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1. Parent is simultaneously submitting a substantially identical letter ruling for another of its wholly-owned subsidiaries, Additional Subsidiary.

On Date 2, the Staff filed a written submission with the Internal Revenue Service, objecting to certain statements set forth in the Statement of Facts of the Date 1 submission that it believed were erroneous or potentially misleading. Parent and Taxpayer did not agree with the concerns but on Date 3, modified and resubmitted the ruling request with a modified Statement of Facts that addresses the Staff's stated factual concerns. In addition, Staff believed that the summaries of its position in the original ruling request submission did not adequately capture the entirety of its legal positions and analysis. Accordingly, Taxpayer's representatives removed its summaries of the Staff's positions and analyses from the ruling request and are willing for the Staff's positions and analyses reflected in its Date 2 submission to speak for themselves. Additionally, Staff submitted an addendum dated Date 4 to its original Date 2 filing attached to the Date 3 submission by Taxpayer. Later, in response to a request for additional information, Taxpayer submitted additional responses on Date 5.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in d states. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a

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calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Income Tax Regulations.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). In its rate case filing in the instant case, Taxpayer reflected a total NOLC deferred tax asset ("DTA") attributable to tax losses for the years Year 1 through the Date 6 test year end by proposing an adjustment to its actual Generally Accepted Accounting Principles (GAAP) and Commission B books of account.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State within the service territory of Taxpayer and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A, were separately subject to the jurisdiction of Commission A, or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments of \$e to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses. On its financial (GAAP) books and its annual and quarterly balance sheets reported on Commission B Form A and Form B, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero on its GAAP books. Similarly, in its annual reports filed with the Agency, the consolidated NOLC as of Date 6 and Date 7, reflected a balance of zero. In the rate base calculated for its General Rate Case ("GRC" filing), Taxpayer restored the DTA in order to reflect a separate return basis.

For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the statutory rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. Tax expense for the test year of approximately \$f was thus calculated on a fully-normalized basis to include both current and deferred taxes on a stand-alone basis unreduced for any NOL. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates, or the non-State property of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to

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as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. (Rev. Proc. 2020-39, Section 2.05.) The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's actual financial (GAAP) books and as a result did not include any adjustment for the separate return NOLC DTA. Had the calculation of EDIT taken into account the separate return NOLC DTA, it would have resulted in a reduction to the balance of \$g. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current GRC, Taxpayer determined that amortization of its EDIT must take into account the \$g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In Taxpayer's current GRC, the Staff asserted that no DTA was allowable to Taxpayer because its GAAP books and Commission B Form A and Form B reflected a balance of zero. Staff's alternative positions are that if the DTA is restored to rate base, then either (i) the \$e of used and useful property that Taxpayer purportedly acquired using the TAA payments should be removed from rate base, or (ii) the \$e of TAA payments received by Taxpayer should be treated as additional zero-cost capital.

Taxpayer asserted that the adoption of Staff's proposal would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Specifically, Taxpayer contended that the adjustment to remove used and useful assets from rate base, while computing depreciation expense, tax expense and the reserve for deferred taxes by including such assets, would violate the consistency rules. Moreover, Taxpayer asserted that the Staff proposal would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate. Finally, Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue.

The administrative law judges presiding over the GRC recommended that Commission A adopt Staff's position, and Taxpayer filed its exceptions to that recommendation. The parties appeared at an open Commission A hearing held on Date 8. Commission A issued a final order on Date 9 adopting Staff's position, but it is aware that Taxpayer is filing this private letter ruling request.

In Staff's submission dated Date 2, Staff allege that Taxpayer's ratemaking regulated books of account did not reflect the NOLC DTA balance unreduced by the TAA payments. Staff note that Taxpayer confirmed in response to a discovery request

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(answered as if under oath) that the balance of its NOLC DTA at the Date 10 test year end on its books and records kept in accordance with the Commission 2 System and reported on its Commission 2 Form for that date, was zero. Staff assert that Commission A's Rules require a major electric utility like Taxpayer to maintain, for purposes of accounting and reporting to Commission A, its books and records in accordance with the uniform system of accounts adopted and amended by Commission B for all regulatory purposes. The term "all regulatory purposes" includes ratemaking. Thus, Taxpayer's regulatory books and records for the Commission B and State jurisdictions are the same as its ratemaking books which reflected the NOLC DTA actual balance of zero at the end of the test year.

In response to these concerns raised by Commission A on its submission dated Date 2, Taxpayer explained more in its additional submission dated Date 5 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

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Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ... " The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the "separate return methodology," however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A



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and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

#### RULINGS REQUESTED

Taxpayer requests the following rulings:

1. The implementation of Staff's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a rate order reducing the used and useful public utility property includible in rate base in an amount equal to the TAA payments, treating the TAA payments as additional zero-cost capital or eliminating the DTA to reflect the TAA payments while computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes would violate the consistency rules of § 168(i)(9)(B).
3. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
4. Implementation of Staff's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property.

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## LAW & 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.

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 that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a 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 (hereinafter 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

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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 tax expense in computing cost of service in such ratemaking.

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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.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

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. 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. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule 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. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes. Therefore, in regard to request (2), the Normalization Rules do not allow Taxpayer to adjust its rate base in an amount equal to the TAA payments, treat the TAA payments as additional zero-cost capital, or eliminate the DTA to reflect the TAA payments while

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INTERNAL REVENUE SERVICE



FAX TRANSMISSION  
Cover Sheet

Date: April 03, 2024

**To: Vice President of Tax**

Address/Organization: \_\_\_\_\_

Fax Number: (614) 716-2777 Office Number: \_\_\_\_\_

**From: Martha M. Garcia**

Address/Organization: CC:PSI:B6

Fax Number: \_\_\_\_\_ Office Number: (202) 317-6853

Number of pages: 32 Including cover page

**Subject:** PLR-105951-22

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The original fax consisted of 032 pages of which  
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This fax should contain the remaining 021 pages.

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ad,  
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computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes. Doing so would violate the Consistency Rule of § 168(i)(9)(B).

Adjustment of Taxpayer's rate base in an amount equal to the TAA payments or treating the TAA payments as additional zero-cost capital would, in effect, flow through the tax benefits of accelerated depreciation deductions to rate payers. This is so even if the intent of such reduction is not specifically to mitigate the effects of the normalization rules. 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). Accordingly, any adjustment of rate base or treating amounts as zero cost capital that has the effect of offsetting some or all of the level of revenues that would flow through would violate the normalization requirements of § 168(i)(9) of the Code.

Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (3), based on the response to requests (1) and (2), Taxpayer's amortization of its EDIT must take into account the \$g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the \$g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (4), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities

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from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

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. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking.

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The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

### RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. The implementation of Staff's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a rate order reducing the used and useful public utility property includible in rate base in an amount equal to the TAA payments, treating the TAA payments as additional zero-cost capital or eliminating the DTA to reflect the TAA payments while computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes would violate the consistency rules of § 168(i)(9)(B).
3. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
4. Implementation of Staff's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

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.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement 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.



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In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

Patrick S. Kirwan

Digitally signed by Patrick S.  
Kirwan  
Date: 2024.03.08 09:35:03  
-05'00'

Patrick S. Kirwan  
Chief, Branch 6  
Office of the Associate Chief Counsel  
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes

04/03/2024 10:50:17 AM -0500 OFFICE OF CHIEF COUNSEL

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Melanie Chivers, LB&I Policy Office

**Internal Revenue Service**

Department of the Treasury  
Washington, DC 20224

Index Number: 168.24-01

Third Party Communication:  
Date of Communication: N/A

Person To Contact:  
, ID No.

Telephone Number:

Refer Reply To:  
CC:PSI:B6  
PLR-105951-22

Date:  
March 8, 2024

**Legend:**

Parent =

Taxpayer =

Additional Subsidiary =

Date 1 =

Date 2 =

Date 3 =

Date 4 =

Date 5 =

Date 6 =

Date 7 =

Date 8 =

Date 9 =

Date 10 =

Commission A =

Commission B =

Staff =

a =

b =

c =

d =

e =

f =

g =

Year 1 =

State =

System =

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Form	=
Form A	=
Form B	=
Rules	=
Enforcement Matter	=
Agency	=
Opinion	=

Dear :

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1. Parent is simultaneously submitting a substantially identical letter ruling for another of its wholly-owned subsidiaries, Additional Subsidiary.

On Date 2, the Staff filed a written submission with the Internal Revenue Service, objecting to certain statements set forth in the Statement of Facts of the Date 1 submission that it believed were erroneous or potentially misleading. Parent and Taxpayer did not agree with the concerns but on Date 3, modified and resubmitted the ruling request with a modified Statement of Facts that addresses the Staff's stated factual concerns. In addition, Staff believed that the summaries of its position in the original ruling request submission did not adequately capture the entirety of its legal positions and analysis. Accordingly, Taxpayer's representatives removed its summaries of the Staff's positions and analyses from the ruling request and are willing for the Staff's positions and analyses reflected in its Date 2 submission to speak for themselves. Additionally, Staff submitted an addendum dated Date 4 to its original Date 2 filing attached to the Date 3 submission by Taxpayer. Later, in response to a request for additional information, Taxpayer submitted additional responses on Date 5.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in d states. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a

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calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Income Tax Regulations.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). In its rate case filing in the instant case, Taxpayer reflected a total NOLC deferred tax asset ("DTA") attributable to tax losses for the years Year 1 through the Date 6 test year end by proposing an adjustment to its actual Generally Accepted Accounting Principles (GAAP) and Commission B books of account.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State within the service territory of Taxpayer and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A, were separately subject to the jurisdiction of Commission A, or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments of \$e to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses. On its financial (GAAP) books and its annual and quarterly balance sheets reported on Commission B Form A and Form B, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero on its GAAP books. Similarly, in its annual reports filed with the Agency, the consolidated NOLC as of Date 6 and Date 7, reflected a balance of zero. In the rate base calculated for its General Rate Case ("GRC" filing), Taxpayer restored the DTA in order to reflect a separate return basis.

For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the statutory rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. Tax expense for the test year of approximately \$f was thus calculated on a fully-normalized basis to include both current and deferred taxes on a stand-alone basis unreduced for any NOL. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates, or the non-State property of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to

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as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. (Rev. Proc. 2020-39, Section 2.05.) The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's actual financial (GAAP) books and as a result did not include any adjustment for the separate return NOLC DTA. Had the calculation of EDIT taken into account the separate return NOLC DTA, it would have resulted in a reduction to the balance of \$g. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current GRC, Taxpayer determined that amortization of its EDIT must take into account the \$g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In Taxpayer's current GRC, the Staff asserted that no DTA was allowable to Taxpayer because its GAAP books and Commission B Form A and Form B reflected a balance of zero. Staff's alternative positions are that if the DTA is restored to rate base, then either (i) the \$e of used and useful property that Taxpayer purportedly acquired using the TAA payments should be removed from rate base, or (ii) the \$e of TAA payments received by Taxpayer should be treated as additional zero-cost capital.

Taxpayer asserted that the adoption of Staff's proposal would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Specifically, Taxpayer contended that the adjustment to remove used and useful assets from rate base, while computing depreciation expense, tax expense and the reserve for deferred taxes by including such assets, would violate the consistency rules. Moreover, Taxpayer asserted that the Staff proposal would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate. Finally, Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue.

The administrative law judges presiding over the GRC recommended that Commission A adopt Staff's position, and Taxpayer filed its exceptions to that recommendation. The parties appeared at an open Commission A hearing held on Date 8. Commission A issued a final order on Date 9 adopting Staff's position, but it is aware that Taxpayer is filing this private letter ruling request.

In Staff's submission dated Date 2, Staff allege that Taxpayer's ratemaking regulated books of account did not reflect the NOLC DTA balance unreduced by the TAA payments. Staff note that Taxpayer confirmed in response to a discovery request

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(answered as if under oath) that the balance of its NOLC DTA at the Date 10 test year end on its books and records kept in accordance with the Commission 2 System and reported on its Commission 2 Form for that date, was zero. Staff assert that Commission A's Rules require a major electric utility like Taxpayer to maintain, for purposes of accounting and reporting to Commission A, its books and records in accordance with the uniform system of accounts adopted and amended by Commission B for all regulatory purposes. The term "all regulatory purposes" includes ratemaking. Thus, Taxpayer's regulatory books and records for the Commission B and State jurisdictions are the same as its ratemaking books which reflected the NOLC DTA actual balance of zero at the end of the test year.

In response to these concerns raised by Commission A on its submission dated Date 2, Taxpayer explained more in its additional submission dated Date 5 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

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Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ... " The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the "separate return methodology," however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A



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and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

#### RULINGS REQUESTED

Taxpayer requests the following rulings:

1. The implementation of Staff's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a rate order reducing the used and useful public utility property includible in rate base in an amount equal to the TAA payments, treating the TAA payments as additional zero-cost capital or eliminating the DTA to reflect the TAA payments while computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes would violate the consistency rules of § 168(i)(9)(B)
3. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
4. Implementation of Staff's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property.

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## LAW & 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.

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 that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a 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 (hereinafter 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

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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 tax expense in computing cost of service in such ratemaking.

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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.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

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. 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. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule 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. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes. Therefore, in regard to request (2), the Normalization Rules do not allow Taxpayer to adjust its rate base in an amount equal to the TAA payments, treat the TAA payments as additional zero-cost capital, or eliminate the DTA to reflect the TAA payments while

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computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes. Doing so would violate the Consistency Rule of § 168(i)(9)(B).

Adjustment of Taxpayer's rate base in an amount equal to the TAA payments or treating the TAA payments as additional zero-cost capital would, in effect, flow through the tax benefits of accelerated depreciation deductions to rate payers. This is so even if the intent of such reduction is not specifically to mitigate the effects of the normalization rules. 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). Accordingly, any adjustment of rate base or treating amounts as zero cost capital that has the effect of offsetting some or all of the level of revenues that would flow through would violate the normalization requirements of § 168(i)(9) of the Code.

Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (3), based on the response to requests (1) and (2), Taxpayer's amortization of its EDIT must take into account the \$g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the \$g related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (4), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities

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from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

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. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking.

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The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

### RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. The implementation of Staff's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a rate order reducing the used and useful public utility property includible in rate base in an amount equal to the TAA payments, treating the TAA payments as additional zero-cost capital or eliminating the DTA to reflect the TAA payments while computing book and tax depreciation, tax expense, and the deferred tax reserve with respect to Taxpayer's public utility property for ratemaking purposes would violate the consistency rules of § 168(i)(9)(B).
3. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
4. Implementation of Staff's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

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.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement 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.

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In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

/s/

Patrick S. Kirwan  
Chief, Branch 6  
Office of the Associate Chief Counsel  
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes



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cc:

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INTERNAL REVENUE SERVICE



**FAX TRANSMISSION  
Cover Sheet**

Date: April 03, 2024

**To: Vice President of Tax**

Address/Organization: \_\_\_\_\_

Fax Number: (614) 716-2777 Office Number: \_\_\_\_\_

**From: Martha M. Garcia**

Address/Organization: CC:PSI:B6

Fax Number: \_\_\_\_\_ Office Number: (202) 317-6853

Number of pages: 31 *Including cover page*

**Subject:** PLR-105952-22

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**Internal Revenue Service**

**Department of the Treasury**  
Washington, DC 20224

Index Number: 168.24-01

Third Party Communication:  
Date of Communication: N/A

Person To Contact:  
, ID No.

Telephone Number:

Refer Reply To:  
CC:PSI:B6  
PLR-105952-22

Date:  
March 8, 2024

**Legend:**

Parent	=
Taxpayer	=
Additional Subsidiary	=
Date 1	=
Date 2	=
Date 3	=
Date 4	=
Date 5	=
Commission A	=
Commission B	=
Staff	=
<u>a</u>	=
<u>b</u>	=
<u>c</u>	=
<u>d</u>	=
<u>e</u>	=
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<u>h</u>	=
Year 1	=
Year 2	=
State	=
Intervenor A	=
Intervenor B	=
Form A	=

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Form B =  
Enforcement Matter =  
Agency =  
Opinion =

Dear :

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. In response to a request for additional information, Taxpayer submitted additional responses on Date 2. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1. Parent is simultaneously submitting a substantially identical letter ruling for another of its wholly-owned subsidiaries, Additional Subsidiary.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in State. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Regulations.

Staff refers to the employees of Commission A who participated in the rate proceeding culminating in the proposed rate order at issue in this private letter ruling request.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). In its rate case filing in the instant case, Taxpayer recorded a total NOLC deferred tax asset ("DTA") attributable to tax losses for the years Year 1 through the Date 3 test year end. In its current General Rate Case ("GRC") (which is the GRC to which this ruling request relates), Taxpayer originally included a DTA of \$d, which was based on its NOLC balance through the end of the test year ended Date 3. In response to a discovery request, Taxpayer updated its DTA for ratemaking purposes to reflect additional net operating losses through Date 4, which resulted in Taxpayer presenting a DTA balance of \$e as of Date 4. The updated amount included losses incurred by Taxpayer due to a winter storm that occurred in

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Year 2, with the increase in the DTA largely attributable to expenses associated with the storm. Subsequent to that, in its rebuttal testimony Taxpayer further adjusted the DTA balance presented in the GRC to remove the portion attributable to the winter storm losses. The final NOLC DTA that Taxpayer sought to include in its rate base in the current GRC was \$f. Approximately g% of that balance is attributable to accelerated depreciation using the "with or without" approach pursuant to which an NOL is treated as being created first by accelerated tax depreciation and only to the extent the NOL is larger than the accelerated tax depreciation deductions is it considered to have been created by other tax deductions.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses. On its financial (GAAP) books, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero.

For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the federal statutory tax rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. See Rev. Proc. 2020-39, Section 2.05. The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's financial (GAAP) books and as a result did not include any adjustment for the NOLC DTA. Had the calculation of EDIT taken into account the NOLC DTA, it would have resulted in a reduction to the balance of \$h. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT

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balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current GRC, Taxpayer determined that amortization of its EDIT must take into account the \$h related to the NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In the rate case at issue, the Staff did not initially take a position on whether Taxpayer's stand-alone DTA should be reduced by reason of the TAA payments. However, intervenors in the case, Intervenor A and Intervenor B, entered testimony advocating for elimination of Taxpayer's standalone NOLC DTA.

Intervenor A took the position that the payments received under the TAA were cost-free capital received by Taxpayer, and, therefore, must be reflected as an increase in Taxpayer's ADIT reserve in order to reduce rate base. Intervenor A's position it that it would be inappropriate to allow a utility holding company to be able to benefit from cost-free tax savings generated by its loss-generating utility subsidiaries. Intervenor A's expert witness testified that no normalization violation results from eliminating Taxpayer's standalone NOLC DTA because that balance is based on a hypothetical standalone return, rather than reflecting the actual utilization of Taxpayer's loss in the Parent consolidated tax return.

Intervenor B pointed to the elimination of the DTA on Taxpayer's financial (GAAP) books resulting from the TAA payments notwithstanding that Taxpayer's ratemaking regulated books of account continued to reflect the DTA unreduced by the TAA payments. Additionally, Intervenor B argued that the NOLC DTA should be excluded from rate base because Taxpayer has been compensated for the NOLC by affiliates.

Both Intervenor A and Intervenor B asserted that there was no authority that specifically mandated separate return ratemaking treatment for the four depreciation-related elements of normalization or prohibited the elimination of the DTA upon receipt of tax sharing payments from affiliates.

Following the introduction of testimony from Intervenor A and Intervenor B, Staff filed rebuttal testimony in which it recommended that Taxpayer's NOLC DTA should be included in rate base subject to refund if the IRS were to issue a PLR concluding that removal of the NOLC DTA did not constitute a normalization violation.

Taxpayer asserted that excluding Taxpayer's standalone NOLC DTA from rate base would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Taxpayer also asserted that excluding the NOLC DTA from rate base as advocated by the intervenors in the case would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable,

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that is, the profits of affiliates and/or the TAA payments, other than the method and life difference between book and tax depreciation and the statutory tax rate.

Taxpayer explained more in its additional submission dated Date 2 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.



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Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ... " The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the "separate return methodology," however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial

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statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

Taxpayer, Staff, and the intervenors in the case entered into a Joint Stipulation and Settlement Agreement (the "Settlement"). Pursuant to the terms of the Settlement, the stipulating parties agreed that the return on the NOLC DTA will be excluded from the base rate revenue requirement resulting from the rate case. Instead, the stipulating parties would request Commission A allow that amount to be deferred as a regulatory asset until rates are effective in Taxpayer's next base rate case. If Taxpayer obtains a PLR concluding that excluding Taxpayer's stand-alone NOLC DTA from rate base would constitute a normalization violation, such regulatory asset will be recovered over a 20 month period through an interim rate adjustment to the Excess Tax Reserve Rider following Taxpayer's receipt of a PLR. On Date 5, Commission A adopted the terms of the Settlement, including those relating to the NOLC DTA. Taxpayer is seeking this private letter ruling in accordance with the terms of the Settlement.

#### RULINGS REQUESTED

Taxpayer requests the following rulings:

1. The implementation of either Intervenor A's or Intervenor B's proposals to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Implementation of either Intervenor A's or Intervenor B's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property.

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## LAW & 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.

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 that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a 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 (hereinafter 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

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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 tax expense in computing cost of service in such ratemaking.

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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.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

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. 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. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule 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. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes.

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Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (2), based on the response to request (1), Taxpayer's amortization of its EDIT must take into account the \$h related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the \$h related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (3), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA

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account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

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. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking. The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

#### RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. The implementation of either Intervenor A's or Intervenor B's proposals to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).

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2. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Implementation of either Intervenor A's or Intervenor B's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

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.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement 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 representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

/s/

Patrick S. Kirwan  
Chief, Branch 6  
Office of the Associate Chief Counsel  
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes



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cc:

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**Internal Revenue Service**

**Department of the Treasury**  
Washington, DC 20224

Index Number: 168.24-01

Third Party Communication:  
Date of Communication: N/A

Vice President - Tax  
American Electric Power Company Inc.  
1 Riverside Plaza  
Columbus, OH 43215  
FAX: (614) 716-2777

Person To Contact:  
Martha M. Garcia, ID No. 0630922  
Telephone Number:  
(202) 317-6853  
Refer Reply To:  
CC:PSI:B6  
PLR-105952-22  
Date:  
March 8, 2024

**Legend:**

Parent	=	American Electric Power Company, Inc. (AEP) E.I.N. 13-4922640
Taxpayer	=	Public Service Company of Oklahoma (PSO) E.I.N. 73-0410895
Additional Subsidiary	=	Southwestern Electric Power Company (SWEPCO) E.I.N. 72-0323455
Date 1	=	March 4, 2022
Date 2	=	August 26, 2022
Date 3	=	December 31, 2020
Date 4	=	June 30, 2021
Date 5	=	December 28, 2021
Commission A	=	Oklahoma Corporation Commission
Commission B	=	Federal Energy Regulatory Commission (FERC)
Staff	=	Staff of Commission A
<u>a</u>	=	5.5 million
<u>b</u>	=	11
<u>c</u>	=	500,000
<u>d</u>	=	154,832,587
<u>e</u>	=	308,501,028
<u>f</u>	=	163,903,995
<u>g</u>	=	92.5
<u>h</u>	=	76,761,405
Year 1	=	2008
Year 2	=	2021
State	=	Oklahoma
Intervenor A	=	Oklahoma Industrial Energy Consumers ("OIEC")
Intervenor B	=	Oklahoma Attorney General
Form A	=	Form 1

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Form B	=	Form 3
Enforcement Matter	=	AI93-5-000
Agency	=	SEC
Opinion	=	Opinion No. 173

Dear Vice President of Tax:

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. In response to a request for additional information, Taxpayer submitted additional responses on Date 2. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1. Parent is simultaneously submitting a substantially identical letter ruling for another of its wholly-owned subsidiaries, Additional Subsidiary.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in State. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Regulations.

Staff refers to the employees of Commission A who participated in the rate proceeding culminating in the proposed rate order at issue in this private letter ruling request.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). In its rate case filing in the instant case, Taxpayer recorded a total NOLC deferred tax asset ("DTA") attributable to tax losses for the years Year 1 through the Date 3 test year end. In its current General Rate Case ("GRC") (which is the GRC to which this ruling request relates), Taxpayer originally included a DTA of \$d, which was based on its NOLC balance through the end of the test year ended Date 3. In response to a discovery request, Taxpayer updated its DTA for ratemaking purposes to reflect additional net operating losses through Date 4, which resulted in Taxpayer presenting a DTA balance of \$e as of Date 4. The updated amount included losses incurred by Taxpayer due to a winter storm that occurred in

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Year 2, with the increase in the DTA largely attributable to expenses associated with the storm. Subsequent to that, in its rebuttal testimony Taxpayer further adjusted the DTA balance presented in the GRC to remove the portion attributable to the winter storm losses. The final NOLC DTA that Taxpayer sought to include in its rate base in the current GRC was \$f. Approximately g% of that balance is attributable to accelerated depreciation using the "with or without" approach pursuant to which an NOL is treated as being created first by accelerated tax depreciation and only to the extent the NOL is larger than the accelerated tax depreciation deductions is it considered to have been created by other tax deductions.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses. On its financial (GAAP) books, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero.

For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the federal statutory tax rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. See Rev. Proc. 2020-39, Section 2.05. The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's financial (GAAP) books and as a result did not include any adjustment for the NOLC DTA. Had the calculation of EDIT taken into account the NOLC DTA, it would have resulted in a reduction to the balance of \$h. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT

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balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current GRC, Taxpayer determined that amortization of its EDIT must take into account the \$h related to the NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In the rate case at issue, the Staff did not initially take a position on whether Taxpayer's stand-alone DTA should be reduced by reason of the TAA payments. However, intervenors in the case, Intervenor A and Intervenor B, entered testimony advocating for elimination of Taxpayer's standalone NOLC DTA.

Intervenor A took the position that the payments received under the TAA were cost-free capital received by Taxpayer, and, therefore, must be reflected as an increase in Taxpayer's ADIT reserve in order to reduce rate base. Intervenor A's position it that it would be inappropriate to allow a utility holding company to be able to benefit from cost-free tax savings generated by its loss-generating utility subsidiaries. Intervenor A's expert witness testified that no normalization violation results from eliminating Taxpayer's standalone NOLC DTA because that balance is based on a hypothetical standalone return, rather than reflecting the actual utilization of Taxpayer's loss in the Parent consolidated tax return.

Intervenor B pointed to the elimination of the DTA on Taxpayer's financial (GAAP) books resulting from the TAA payments notwithstanding that Taxpayer's ratemaking regulated books of account continued to reflect the DTA unreduced by the TAA payments. Additionally, Intervenor B argued that the NOLC DTA should be excluded from rate base because Taxpayer has been compensated for the NOLC by affiliates.

Both Intervenor A and Intervenor B asserted that there was no authority that specifically mandated separate return ratemaking treatment for the four depreciation-related elements of normalization or prohibited the elimination of the DTA upon receipt of tax sharing payments from affiliates.

Following the introduction of testimony from Intervenor A and Intervenor B, Staff filed rebuttal testimony in which it recommended that Taxpayer's NOLC DTA should be included in rate base subject to refund if the IRS were to issue a PLR concluding that removal of the NOLC DTA did not constitute a normalization violation.

Taxpayer asserted that excluding Taxpayer's standalone NOLC DTA from rate base would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Taxpayer also asserted that excluding the NOLC DTA from rate base as advocated by the intervenors in the case would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable,

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that is, the profits of affiliates and/or the TAA payments, other than the method and life difference between book and tax depreciation and the statutory tax rate.

Taxpayer explained more in its additional submission dated Date 2 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

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Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ... " The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the "separate return methodology," however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial

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statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

Taxpayer, Staff, and the intervenors in the case entered into a Joint Stipulation and Settlement Agreement (the "Settlement"). Pursuant to the terms of the Settlement, the stipulating parties agreed that the return on the NOLC DTA will be excluded from the base rate revenue requirement resulting from the rate case. Instead, the stipulating parties would request Commission A allow that amount to be deferred as a regulatory asset until rates are effective in Taxpayer's next base rate case. If Taxpayer obtains a PLR concluding that excluding Taxpayer's stand-alone NOLC DTA from rate base would constitute a normalization violation, such regulatory asset will be recovered over a 20 month period through an interim rate adjustment to the Excess Tax Reserve Rider following Taxpayer's receipt of a PLR. On Date 5, Commission A adopted the terms of the Settlement, including those relating to the NOLC DTA. Taxpayer is seeking this private letter ruling in accordance with the terms of the Settlement.

#### RULINGS REQUESTED

Taxpayer requests the following rulings:

1. The implementation of either Intervenor A's or Intervenor B's proposals to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Implementation of either Intervenor A's or Intervenor B's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property.



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## LAW & 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.

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 that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a 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 (hereinafter 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

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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 tax expense in computing cost of service in such ratemaking.

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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.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

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. 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. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule 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. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes.

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Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (2), based on the response to request (1), Taxpayer's amortization of its EDIT must take into account the \$h related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the \$h related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (3), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA

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account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

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. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking. The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

#### RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. The implementation of either Intervenor A's or Intervenor B's proposals to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).

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2. Putting into effect a final rate order that fails to take into account the NOLC DTA as a reduction to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Implementation of either Intervenor A's or Intervenor B's proposed ratemaking treatments in a final rate order would violate the depreciation normalization rules and thus result in the disallowance of Taxpayer's right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

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.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement 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 representative.

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This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

Patrick S. Kirwan Digitally signed by Patrick S. Kirwan  
Date: 2024.03.08 13:46:04 -05'00'  
Patrick S. Kirwan  
Chief, Branch 6  
Office of the Associate Chief Counsel  
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes

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cc: Alexander Zakupowsky, Jr.  
Miller & Chevalier  
900 Sixteenth St., NW  
Washington, DC 20006  
FAX: (202) 626-5801

James D. Gadwood  
Miller & Chevalier Chartered  
900 Sixteenth St., NW  
Washington, DC 20006  
FAX: (202) 626-5801

Melanie Chivers, LB&I Policy Office



\*\* INBOUND NOTIFICATION : FAX RECEIVED SUCCESSFULLY \*\*

TIME RECEIVED

April 3, 2024 at 2:02:39 PM EDT

REMOTE CSID

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DURATION

1034

PAGES

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STATUS

Received

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INTERNAL REVENUE SERVICE



**FAX TRANSMISSION  
Cover Sheet**

Date: April 03, 2024

**To: Vice President of Tax**

Address/Organization: \_\_\_\_\_

Fax Number: (614) 716-2777 Office Number: \_\_\_\_\_

**From: Martha M Garcia**

Address/Organization: CC:PSI:B6

Fax Number: \_\_\_\_\_ Office Number: 202-317-6853

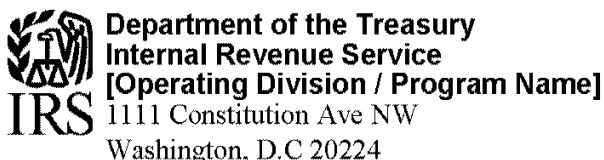
Number of pages: 34 *Including cover page*

**Subject:** PLR-107770-22

This communication is intended for the sole use of the individual to whom it is addressed and may contain confidential information that is privileged, confidential and exempt from disclosure under applicable law. If you are not the intended recipient, you are hereby notified that any dissemination, distribution or copying of this communication is strictly prohibited by the provisions of the Internal Revenue code. If you have received this communication in error, please contact the sender immediately by telephone. Thank you.

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Date:  
04/03/2024  
Last date to request IRS review:  
04/23/2024  
Last date to request delay:  
06/02/2024  
Last date to petition Tax Court:  
06/02/2024  
Date open to public inspection:  
06/28/2024  
Person to contact:  
Chief, Disclosure Support Branch  
Contact telephone number:  
202-317-6840

### Notice of Intention to Disclose

In accordance with Internal Revenue Code (IRC) Section 6110, we intend to make the enclosed copy of your ruling (with deletions) open to public inspection.

IRC Section 6110 provides that copies of certain rulings, technical advice memoranda, and determination letters will be open to public inspection after deletions are made. These written determinations will be open to public inspection online in the Freedom of Information Act (FOIA) Reading Room at **IRS.gov/privacy-disclosure/foia-library**.

We made the deletions indicated in accordance with Section 6110(c), which requires us to delete:

1. The names, addresses, and other identifying details of the person the ruling pertains to, and of any other person identified in the ruling [other than a person making a "third party communication" (see back of this notice)].
2. Information specifically authorized under criteria established by an Executive Order to be kept secret in the interest of national defense or foreign policy, and which is in fact properly classified under such Executive Order.
3. Information specifically exempted from disclosure by any (other than the IRC) which is applicable to the IRS.
4. Trade secrets and commercial or financial information obtained from a person that are privileged or confidential.
5. Information which would constitute a clearly unwarranted invasion of personal privacy.
6. Information contained in or related to examination, operating, or condition reports prepared by, or for use of, an agency that regulates or supervises financial institutions.
7. Geological and geophysical information and data (including maps) concerning wells.

These are the only grounds for deleting material. We made the indicated proposed deletions after considering any suggestions for deletions you may have made prior to issuance of the ruling.

### If you agree with the proposed deletions

You do not need to take any further action. We will place the deleted copy in the online FOIA Reading Room on the "Date open to public inspection" shown on this notice.

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**If you disagree with the proposed deletions**

Please return the copy and show, in brackets, any additional information you believe should be deleted. Include a statement supporting your position. Only material falling within the seven categories listed above may be deleted. Your statement should specify which of these seven categories is applicable with respect to each additional deletion you propose. Mail or fax your deleted copy and statement to:

Attention: Chief, CC:PA:LPD:DS  
Internal Revenue Service  
Ben Franklin Station  
P.O. Box 7604  
Washington, DC 20044  
Fax: 855-592-8978

It must be faxed or postmarked no later than the "Last date to request IRS review" shown on this notice. We will give your submission careful consideration. If we determine we cannot make any or all of the additional deletions you suggest, we will so advise you not later than 20 days after we receive your submission.

Fax your information using either a fax machine or an online fax service. Protect yourself when sending digital data by understanding the fax service's privacy and security policies.

You will then have the right to file a petition in the United States Tax Court if you disagree with us. Your petition must be filed no later than the "Last date to petition Tax Court" shown on this notice, which is 60 days after the mailing date of this notice. If a petition is filed in the Tax Court, the disputed portion(s) of the ruling will not be placed in the Reading Room until after a court decision becomes final.

You can download a fillable petition form and get information about filing at **ustaxcourt.gov**. The Tax Court encourages petitioners to electronically file petitions. You can eFile your completed petition by following the instructions and user guides available on the Tax Court website at **ustaxcourt.gov/dawson.html**. You will need to register for a DAWSON account to do so. Or you may send the completed petition to:

United States Tax Court  
400 Second Street, NW  
Washington, DC 20217

Be sure to include a copy of this notice and any attachments with the petition and the filing fee payable online, or by mail or in person using a check or money order made out to Clerk, U.S. Tax Court. Do not send your petition to the office at the top of this letter or to the IRS; you must file your petition with the Tax Court.

Your petition is timely if the Tax Court receives it within the 60-day period or if it is postmarked by the United States Postal Service within the 60-day period and the envelope containing the petition is properly addressed with the correct postage. The postmark rule doesn't apply if using the mail service of a foreign country. Generally, your petition will be timely if the date marked by a designated private delivery service is within the 60-day period. You can find a list of designated delivery services for domestic and international mailings in Notice 2016-30, which is available on our website at **IRS.gov/pub/irs-drop/n-16-30.pdf**. The list of approved delivery companies is subject to change.

If you lack access to a computer or the internet and want to file a paper petition, you may get a copy of the petition form and filing information by contacting the Office of the Clerk of the Tax Court at the address above or by calling 202-521-0700.

If no petition is filed in the Tax Court, the deleted version of your ruling will be made open to public inspection on the date shown above in the "Date open to public inspection" heading. If the transaction to which the ruling relates will not be completed by then, you may request a delay of public inspection.

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**Request for delay of public inspection**

You may request a delay of public inspection of up to 90 days, or 15 days after the transaction is completed, whichever is later. The request for delay must be received by the IRS no later than the "Last date to request delay" shown on this notice, which is 60 days after the mailing date of this notice. Mail or fax your request for delay to:

Attention: Chief, CC:PA:LPD:DS  
Internal Revenue Service  
Ben Franklin Station  
P.O. Box 7604  
Washington, DC 20044  
Fax: 855-592-8978

You may request a second delay of up to an additional 180 days (or 15 days after the completion of the transaction, whichever is earlier) if the transaction is not completed by the end of the original delay period and if good cause exists for additional delay. We must receive a request for a second delay at the above address at least 30 days before the original delay period ends.

**Requests for additional disclosure**

After the copy of your ruling, with deletions, is placed in our online FOIA Reading Room, any person may request us to make additional portions of the ruling open to public inspection. If we receive a request that involves disclosure of names, addresses, or taxpayer identifying numbers, we will deny the request and you will not be contacted. If that request involves disclosure of anything other than names, addresses, or taxpayer identifying numbers, we will contact you before taking action.

**Third party communication**

The enclosed copy of your ruling may contain the notation "Third Party Communication." This indicates that IRS received a communication (written or oral) regarding your ruling request from a person outside the IRS (other than you or your authorized representative). The date of the communication and the category of the person making the contact (such as "Congressional" or "Trade Association") will be indicated.

If you have any questions regarding this notice, please call us at 202-317-6840.

[Enclosures:]

[cc:]

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**Internal Revenue Service**

**Department of the Treasury**  
Washington, DC 20224

Index Number: 168.24-01

Third Party Communication: None  
Date of Communication: Not Applicable

Person To Contact:  
, ID No.

Telephone Number:

Refer Reply To:  
CC:PSI:B06  
PLR-107770-22

Date:  
March 08, 2024

**Legend:**

Parent	=
Taxpayer	=
Additional Subsidiary	=
Date 1	=
Date 2	=
Date 3	=
Commission A	=
Commission B	=
Commission C	=
Office	=
Group	=
<u>a</u>	=
<u>b</u>	=
<u>c</u>	=
<u>d</u>	=
<u>e</u>	=
<u>f</u>	=
Year 1	=
Year 2	=
Year 3	=
Year 4	=
State	=
Form A	=
Form B	=
Enforcement Matter	=
Agency	=

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Opinion =

Dear :

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. In response to a request for additional information, Taxpayer submitted additional responses on Date 2. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in State. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Income Tax Regulations.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). On its ratemaking books of account for purposes of its current rate case, Taxpayer recorded a total NOLC deferred tax asset ("DTA") attributable to tax losses for certain years during the period Year 1 through the Year 2. The projected NOLC DTA balance as of Date 3 (the end of the test period) is \$d. The entire DTA balance is deemed to be attributable to accelerated depreciation, as determined using the "with or without" approach, pursuant to which an NOL is treated as being created first by accelerated tax depreciation deductions and only to the extent the NOL is larger than the accelerated tax depreciation deductions is it considered to have been created by other tax deductions.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State within the service territory of Taxpayer and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A or were unregulated businesses not subject to the jurisdiction of any public utility commission.

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Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments of \$e to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses.

On its financial (GAAP) books, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero. For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the federal statutory rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. (Rev. Proc. 2020-39, Section 2.05.) The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's financial (GAAP) books and as a result did not include any adjustment for the NOLC DTA. Had the calculation of EDIT taken into account the NOLC DTA, it would have resulted in a reduction to the balance of \$f. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current General Rate Case ("GRC"), Taxpayer determined that consistent with its proposed change in treatment of the NOLC DTA for ratemaking purposes prospectively to comply with the normalization provisions of the Code, that amortization of its EDIT must take into account the \$f related to the NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In the rate case at issue, intervenors in the case – the Office, the Group, and certain Joint Municipalities (Joint Municipals) – entered testimony recommending elimination of Taxpayer's reinstatement of its standalone NOLC DTA, which does not exist on its GAAP books and records.

Office's witness testified that Taxpayer's proposed adjustment to reinstate its standalone NOLC for ratemaking purposes is improper because it would result in a double counting and allow Taxpayer to earn a return on cost-free capital at ratepayers'

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expense. The witness testified that reinstating Taxpayer's NOLC is improper for ratemaking purposes because: 1) Taxpayer received payments from the parent company for the use of its NOLC; 2) Taxpayer took those payments (non-investor cost-free capital) and used the funds to acquire additional rate base assets upon which Taxpayer is earning a full rate base return; 3) the parent company fully utilized the NOL, so there is no carryforward to reinstate; 4) a consolidated group is considered a single entity for tax purposes—thus, Taxpayer's NOLC is \$0 because it has been fully utilized; and 5) the current ratemaking treatment has been followed for the last 12 years without triggering a normalization violation. The existing treatment is appropriate because it tracks with economic realities. Office's witness explained that to reinstate a hypothetical standalone NOLC at the subsidiary level, solely for ratemaking purposes, would violate consistency principles and be contrary to sound ratemaking policy. The witness also testified regarding a pending proceeding before Commission C in which Additional Subsidiary, a regulated utility within Parent's consolidated group, similarly proposed to reinstate its standalone NOLC for ratemaking purposes, but Commission C rejected the proposal based on its finding that such an adjustment would result in a double recovery for the utility at ratepayers' expense.

Group witness testified that utility income tax expenses should be reflected in cost of service in a manner that ensures that the utility's costs are no higher than what the utility could achieve on a stand-alone basis. However, the witness noted that the purpose of an affiliate agreement allows the utility to incur benefits for itself and its ratepayers that could not be achieved on a stand-alone basis. Taxpayer has been participating in the Parent tax agreement for many decades. Because of this agreement, Taxpayer and its ratepayers have benefitted under the tax agreement when Taxpayer has income tax deductions that exceed its taxable income, and those tax benefits can be used by affiliate companies to reduce consolidated taxable income. Under the Parent affiliate tax agreement, cash payments are made to Taxpayer if its tax deductions exceed its taxable income, which are then reflected in its cost of service for rate-setting purposes. Participation in the affiliate tax agreement benefits customers. This practice is consistent across all Parent utility affiliates that participate in the consolidated tax filing agreement, and this agreement maximizes the use of tax deductions available to the consolidated enterprises, and reallocates those affiliates' tax benefits to utility affiliates to reduce cost of service. Because income taxes are no higher for ratemaking purposes than what could be achieved on a stand-alone basis, participation in these affiliate agreements has the effect of benefitting all stakeholders, the utility and its end-use customers. The creation of these consolidated income tax benefits has been permitted under IRS normalization rules, and the reallocation of tax benefits across all participants in a consolidated filing ensures the affiliate that contributes the tax benefits, realizes the benefits, which in turn reduces its cost of service and retail rates. Taxpayer's proposal in this case would no longer pass the consolidated tax benefits on to customers but would retain the benefits for its shareholders.



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The Joint Municipals' witness stated that Taxpayer admitted in discovery responses that its GAAP books accurately reflect it has already received cash payments from its parent, Parent, (the taxpayer) for its NOLC pursuant to the companies' tax sharing agreement and has thus been made whole. Taxpayer's GAAP books show the NOLC as having a \$0 balance, both historically and as budgeted for Year 3 and Year 4, because those cash payments have eliminated the NOLC. By reinstating the NOLC on a standalone basis, however, Taxpayer fails to account for the cash payments from Parent, which it uses to increase its capital at no cost to the Company. Taxpayer is using this already refunded NOLC deferred tax asset solely for rate-making purposes to artificially increase its rate of return. In other words, in the real world, Taxpayer increases its level of capital with the use of the zero-cost NOLC cash payment from Parent, yet by reinstating a stand-alone NOLC deferred tax asset and deducting it from ADFIT solely for regulatory purposes, Taxpayer artificially increases the apparent overall Weighted Average Cost of Capital to be applied to the increased investment. The witness stated that Taxpayer is essentially double counting the impact of its tax burden, once by including a restated NOLC deferred tax asset, and then again by failing to account for the tax sharing payment it received from Parent. She explained that it would only be appropriate to include the NOLC deferred tax asset based on a Taxpayer stand-alone tax return if the payment from Parent for use of the NOLC in a consolidated tax return is credited to Taxpayer's ratepayers. Thus, the witness concluded that Taxpayer's claim that the adjustment to reinstate a stand-alone NOLC deferred tax asset is required by the IRS normalization rules is incorrect when no NOLC deferred tax asset is reported in accordance with GAAP. The witness also noted that Taxpayer did not claim a normalization violation existed in either of its last two State rate cases (both of which were finalized after the TCJA went into effect), and the cumulative effect of the company's proposal would be to reduce the customer refunds previously approved when Taxpayer's tax rate was reduced pursuant to the TCJA.

Taxpayer asserted that excluding Taxpayer's standalone NOLC DTA from the calculation of accumulated deferred income tax ("ADFIT") treated as cost-free capital in Taxpayer's capital structure would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Taxpayer also asserted that excluding the NOLC DTA from ADFIT as advocated by the intervenors in the case would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable, that is, the profits of affiliates and/or the TAA payments, other than the difference between book and tax depreciation and the statutory tax rate.

Taxpayer explained more in its additional submission dated Date 2 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

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Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ...". The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term "stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

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The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the separate return methodology, however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax

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expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

Taxpayer and the intervenors in the case entered into a Joint Stipulation and Settlement Agreement (the "Settlement"). Pursuant to the terms of the Settlement, the stipulating parties agreed that the NOLC DTA will be excluded from ADFIT and treated as cost free capital for purposes of the base rate revenue requirement resulting from the rate case. Instead, the stipulating parties would request the Commission A allow that amount to be deferred as a regulatory asset until rates are effective in Taxpayer's next base rate case. If Taxpayer obtains a PLR concluding that excluding Taxpayer's stand-alone NOLC DTA from ADFIT treated as cost free capital would constitute a normalization violation, Taxpayer will initiate a limited proceeding to update Taxpayer's Tax Rider to reflect the NOLC adjustments, along with any Commission A-approved offsets, in rates on an ongoing basis and to recover the regulatory asset. Taxpayer is seeking this private letter ruling in accordance with the terms of the Settlement.

#### RULINGS REQUESTED

Taxpayer requests the following rulings:

1. Reducing Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments as an offset to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments would result in Taxpayer losing its right to claim accelerated depreciation on all of its State public utility property.

#### LAW & 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.

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 that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

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In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a 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 (hereinafter 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

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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 tax 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.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate

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reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

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. 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. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule 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. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes.

Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (2), based on the response to request (1), Taxpayer's amortization of its EDIT must take into account the \$f related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the \$f related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (3), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev.

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Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

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. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization



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Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking. The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

#### RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. Reducing Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments as an offset to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments would result in Taxpayer losing its right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

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.

The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement 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.

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In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

/s/

Patrick S. Kirwan  
Chief, Branch 6  
Office of the Associate Chief Counsel  
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes

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cc:

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**Internal Revenue Service**

**Department of the Treasury**  
Washington, DC 20224

Index Number: 168.24-01

Third Party Communication:  
Date of Communication: N/A

Vice President - Tax  
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1 Riverside Plaza  
Columbus, OH 43215  
FAX: (614) 716-2777

Person To Contact:  
**Martha M. Garcia**, ID No. 0630922  
Telephone Number:  
**(202) 317-6853**  
Refer Reply To:  
**CC:PSI:B6**  
**PLR-107770-22**  
Date:  
**March 8, 2024**

**Legend:**

Parent	=	American Electric Power Company, Inc. (AEP) E.I.N. 13-4922640
Taxpayer	=	Indiana Michigan Power Company (I&M) E.I.N. 35-0410455
Additional Subsidiary	=	Southwestern Electric Power Company (SWEPCO) E.I.N. 72-0323455
Date 1	=	April 1, 2022
Date 2	=	August 26, 2022
Date 3	=	December 31, 2022
Commission A	=	Indiana Utility Regulatory Commission (IURC)
Commission B	=	Federal Energy Regulatory Commission (FERC)
Commission C	=	Texas Public Utility Commission (PUCT)
Office	=	Indiana Office of Utility Consumer (OUCC)
Group	=	I&M Industrial Group
<u>a</u>	=	5.5 million
<u>b</u>	=	11
<u>c</u>	=	600,000
<u>d</u>	=	43,191,239
<u>e</u>	=	159,604,598
<u>f</u>	=	139,848,804
Year 1	=	2009
Year 2	=	2017
Year 3	=	2021
Year 4	=	2022
State	=	Indiana
Form A	=	Form 1
Form B	=	Form 3
Enforcement Matter	=	AI93-5-000

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Agency = SEC  
Opinion = Opinion No. 173

Dear Vice President of Tax:

On Date 1, on behalf of Parent and its wholly-owned subsidiary, Taxpayer, Parent's and Taxpayer's authorized representatives requested rulings under § 168(i)(9) regarding the potential implementation of a proposed ratemaking adjustment under the depreciation normalization provisions of the Internal Revenue Code of 1986, as amended ("Code") and the regulations thereunder. In response to a request for additional information, Taxpayer submitted additional responses on Date 2. Taxpayer's request is made pursuant to, and in compliance with, Rev. Proc. 2022-1.

Parent, through its operating subsidiaries, serves nearly a customers in b states. Taxpayer, a wholly owned subsidiary of Parent, is a regulated public utility serving more than c customers in State. As a member of the Parent affiliated group, Taxpayer joins in the filing of a consolidated return with other Parent operating companies. As is relevant to this private letter ruling request, Taxpayer is subject to the ratemaking jurisdiction of Commission A.

Parent and each of its subsidiaries are accrual basis taxpayers. Parent is the common parent of an affiliated group of corporations filing a consolidated return on a calendar-year basis. Parent, as the common parent of the affiliated group, serves as the agent of Taxpayer for purposes of this private letter ruling request pursuant to § 1.1502-77(a) of the Income Tax Regulations.

On a separate return basis, Taxpayer had a federal income tax net operating loss carry-forward ("NOLC"). On its ratemaking books of account for purposes of its current rate case, Taxpayer recorded a total NOLC deferred tax asset ("DTA") attributable to tax losses for certain years during the period Year 1 through the Year 2. The projected NOLC DTA balance as of Date 3 (the end of the test period) is \$d. The entire DTA balance is deemed to be attributable to accelerated depreciation, as determined using the "with or without" approach, pursuant to which an NOL is treated as being created first by accelerated tax depreciation deductions and only to the extent the NOL is larger than the accelerated tax depreciation deductions is it considered to have been created by other tax deductions.

Under the Parent Tax Allocation Agreement ("TAA") amongst the Parent affiliated group members joining in the filing of a consolidated return, certain profitable members of the affiliated group were able to utilize the Taxpayer NOLC to offset their separate company taxable income. None of these profitable subsidiaries provided electric utility service to customers in State within the service territory of Taxpayer

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and their operations were either subject to the jurisdiction of Commission B and/or state public utility commissions other than Commission A or were unregulated businesses not subject to the jurisdiction of any public utility commission.

Pursuant to the TAA, the profitable members made cash payments to Parent for their separate return tax liability, and Parent remitted cash payments of \$e to Taxpayer for the tax benefit derived by the affiliated group from the use of Taxpayer's losses.

On its financial (GAAP) books, Taxpayer reduced its DTA for the NOLC to reflect the receipt of cash for the use of its loss by other members of the affiliated group, thereby recording an adjusted DTA balance of zero. For ratemaking purposes, Taxpayer includes all used and useful public utility property in rate base, calculates depreciation expense thereon using a straight-line method, depreciates such property for federal income tax purposes using accelerated depreciation (MACRS), and makes an adjustment to the reserve for deferred taxes (at the federal statutory rate) to reflect the difference in tax liability attributable to the use of different depreciation methods for book and tax purposes. All of these calculations were done on a separate return basis without regard to the property, tax attributes, or separate tax liability, of affiliates of Taxpayer.

In accordance with section 13001 of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA"), Taxpayer calculated its so-called excess deferred income taxes ("EDIT") as of December 31, 2017, representing the amount of accelerated depreciation-related taxes previously collected from customers that had not yet been paid by Taxpayer and became excess due to the reduction in tax rates in the TCJA. (Rev. Proc. 2020-39, Section 2.05.) The total EDIT so-calculated was based on the deferred tax balances on Taxpayer's financial (GAAP) books and as a result did not include any adjustment for the NOLC DTA. Had the calculation of EDIT taken into account the NOLC DTA, it would have resulted in a reduction to the balance of \$f. Pursuant to TCJA § 13001(d)(1), Taxpayer began amortizing the unadjusted EDIT balance on its ratemaking books in accordance with the Average Rate Assumption Method ("ARAM") beginning as of January 1, 2018. In connection with the preparation of Taxpayer's current General Rate Case ("GRC"), Taxpayer determined that consistent with its proposed changed in treatment of the NOLC DTA for ratemaking purposes prospectively to comply with the normalization provisions of the Code, that amortization of its EDIT must take into account the \$f related to the NOLC DTA as a reduction to the total EDIT available to be amortized and seeks to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39.

In the rate case at issue, intervenors in the case – the Office, the Group, and certain Joint Municipalities (Joint Municipals) – entered testimony recommending elimination of Taxpayer's reinstatement of its standalone NOLC DTA, which does not exist on its GAAP books and records.

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Office's witness testified that Taxpayer's proposed adjustment to reinstate its standalone NOLC for ratemaking purposes is improper because it would result in a double counting and allow Taxpayer to earn a return on cost-free capital at ratepayers' expense. The witness testified that reinstating Taxpayer's NOLC is improper for ratemaking purposes because: 1) Taxpayer received payments from the parent company for the use of its NOLC; 2) Taxpayer took those payments (non-investor cost-free capital) and used the funds to acquire additional rate base assets upon which Taxpayer is earning a full rate base return; 3) the parent company fully utilized the NOL, so there is no carryforward to reinstate; 4) a consolidated group is considered a single entity for tax purposes—thus, Taxpayer's NOLC is \$0 because it has been fully utilized; and 5) the current ratemaking treatment has been followed for the last 12 years without triggering a normalization violation. The existing treatment is appropriate because it tracks with economic realities. Office's witness explained that to reinstate a hypothetical standalone NOLC at the subsidiary level, solely for ratemaking purposes, would violate consistency principles and be contrary to sound ratemaking policy. The witness also testified regarding a pending proceeding before Commission C in which Additional Subsidiary, a regulated utility within Parent's consolidated group, similarly proposed to reinstate its standalone NOLC for ratemaking purposes, but Commission C rejected the proposal based on its finding that such an adjustment would result in a double recovery for the utility at ratepayers' expense.

Group witness testified that utility income tax expenses should be reflected in cost of service in a manner that ensures that the utility's costs are no higher than what the utility could achieve on a stand-alone basis. However, the witness noted that the purpose of an affiliate agreement allows the utility to incur benefits for itself and its ratepayers that could not be achieved on a stand-alone basis. Taxpayer has been participating in the Parent tax agreement for many decades. Because of this agreement, Taxpayer and its ratepayers have benefitted under the tax agreement when Taxpayer has income tax deductions that exceed its taxable income, and those tax benefits can be used by affiliate companies to reduce consolidated taxable income. Under the Parent affiliate tax agreement, cash payments are made to Taxpayer if its tax deductions exceed its taxable income, which are then reflected in its cost of service for rate-setting purposes. Participation in the affiliate tax agreement benefits customers. This practice is consistent across all Parent utility affiliates that participate in the consolidated tax filing agreement, and this agreement maximizes the use of tax deductions available to the consolidated enterprises, and reallocates those affiliates' tax benefits to utility affiliates to reduce cost of service. Because income taxes are no higher for ratemaking purposes than what could be achieved on a stand-alone basis, participation in these affiliate agreements has the effect of benefitting all stakeholders, the utility and its end-use customers. The creation of these consolidated income tax benefits has been permitted under IRS normalization rules, and the reallocation of tax benefits across all participants in a consolidated filing ensures the affiliate that contributes the tax benefits, realizes the benefits, which in turn reduces its cost of service and retail rates. Taxpayer's proposal in this case would no longer pass the

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consolidated tax benefits on to customers but would retain the benefits for its shareholders.

The Joint Municipals' witness stated that Taxpayer admitted in discovery responses that its GAAP books accurately reflect it has already received cash payments from its parent, Parent, (the taxpayer) for its NOLC pursuant to the companies' tax sharing agreement and has thus been made whole. Taxpayer's GAAP books show the NOLC as having a \$0 balance, both historically and as budgeted for Year 3 and Year 4, because those cash payments have eliminated the NOLC. By reinstating the NOLC on a standalone basis, however, Taxpayer fails to account for the cash payments from Parent, which it uses to increase its capital at no cost to the Company. Taxpayer is using this already refunded NOLC deferred tax asset solely for rate-making purposes to artificially increase its rate of return. In other words, in the real world, Taxpayer increases its level of capital with the use of the zero-cost NOLC cash payment from Parent, yet by reinstating a stand-alone NOLC deferred tax asset and deducting it from ADFIT solely for regulatory purposes, Taxpayer artificially increases the apparent overall Weighted Average Cost of Capital to be applied to the increased investment. The witness stated that Taxpayer is essentially double counting the impact of its tax burden, once by including a restated NOLC deferred tax asset, and then again by failing to account for the tax sharing payment it received from Parent. She explained that it would only be appropriate to include the NOLC deferred tax asset based on a Taxpayer stand-alone tax return if the payment from Parent for use of the NOLC in a consolidated tax return is credited to Taxpayer's ratepayers. Thus, the witness concluded that Taxpayer's claim that the adjustment to reinstate a stand-alone NOLC deferred tax asset is required by the IRS normalization rules is incorrect when no NOLC deferred tax asset is reported in accordance with GAAP. The witness also noted that Taxpayer did not claim a normalization violation existed in either of its last two State rate cases (both of which were finalized after the TCJA went into effect), and the cumulative effect of the company's proposal would be to reduce the customer refunds previously approved when Taxpayer's tax rate was reduced pursuant to the TCJA.

Taxpayer asserted that excluding Taxpayer's standalone NOLC DTA from the calculation of accumulated deferred income tax ("ADFIT") treated as cost-free capital in Taxpayer's capital structure would violate the normalization rules of § 168(i)(9), and particularly the consistency rules of § 168(i)(9)(B). Taxpayer also asserted that excluding the NOLC DTA from ADFIT as advocated by the intervenors in the case would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2) by introducing a variable, that is, the profits of affiliates and/or the TAA payments, other than the difference between book and tax depreciation and the statutory tax rate.

Taxpayer explained more in its additional submission dated Date 2 that journal entries are not made to the financial statements of Taxpayer to re-establish the NOLC DTA for ratemaking purposes. Taxpayer says the tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group.



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Taxpayer represents that this methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Taxpayer explains that the "separate return method" terminology used by Agency is a method of allocating taxes amongst the members of an affiliate group. This methodology allocates current and deferred taxes to members of the group as if it were a separate taxpayer.

Regarding Commission B Financial Reporting, Taxpayer explains that Commission B issued Enforcement Matter to discuss the acceptable accounting for income taxes, addressing both a "separate return method" and a "stand alone method" of accounting. Commission B describes the "separate return method" as a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer, which is similar to the definition of separate return used by the Agency. Under the "separate return method," the sum of the individual member's allocations will not align with the consolidated tax return. In Enforcement Matter, Commission B also defines the "stand alone method" and distinguishes it from the "separate return method". The "stand alone method" allocates the consolidated group tax expense to individual members through the recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under this method, the sum of the amounts allocated to individual members equals the consolidated amount. Commission B concludes in Enforcement Matter that Commission B requires the use of the "stand alone method" and expressly provides that the use of the "separate return method" will not be permitted for Commission B financial accounting and reporting (Commission B Form A and Form B.)

Commission B has issued several decisions rejecting the use of the "separate return method" for determining income tax expense when an entity files as part of a consolidated group. Instead, Commission B relies on the "stand alone method" of allocating income taxes between members of a consolidated group. Under the "stand alone method," the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the "stand alone method," the sum of amounts allocated to individual members equal the consolidated amount.

Regarding Commission B Ratemaking, Opinion from Commission B describes the "stand alone method" as an income tax allowance "that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities ...". The "stand alone method" results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Based on this definition, for ratemaking purposes, the Commission B-approved tax allocation method for ratemaking purposes aligns with the Agency definition of "separate return method" despite using the term

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"stand alone method" in that the tax expense is only attributable to the cost of service and the activities involved in providing service to a utility's customers.

The receipt of cash from the Taxpayer's Parent Company for the consolidated utilization of the NOL results in the DTA being reduced to zero on Commission B Form A and Form B. Journal entries are not made to the financial statements of the subsidiary to re-establish the NOLC DTA for ratemaking purposes. The tax allocation method utilized by the Parent group for financial reporting reflects the NOLC (and other tax attributes) as realized or realizable when it is realized or realizable by the consolidated group. This methodology conforms to the requirements outlined by Commission B for financial accounting and reporting (Form A and Form B) in Enforcement Matter.

Because no journal entries are recorded to the financial statements to re-establish the DTA, Taxpayer represents that it is necessary to make adjustments for ratemaking purposes in order to comply with the normalization rules. Accordingly, these adjustments are incorporated into the filing package presented to the respective state regulatory bodies as part of the Taxpayer's rate requests. The filing packages include schedules that start with the financial information on Commission B's Form A and Form B and the financial information presented in Agency financial statements. Consistent with the separate return methodology, however, adjustments are made to align the rate request with the revenues and costs entering into the regulated cost of service. These adjustments are where the NOLC DTA is re-established as a component of accumulated deferred income taxes.

Taxpayer emphasizes the role that Commission B Form A and Form B play (and do not play) in the ratemaking context. Taxpayer asserts that Commission B Form A and Form B are simply the starting point for the financial data included in ratemaking. Adjustments are then made to arrive at the end result of a tax allowance for the test year associated with the provision of utility service to the regulatory jurisdiction's customers. The financial statement data in Commission B Form A and Form B are first adjusted to remove items of income and expense that are not associated with the provision of utility service. An example of one of these items is the expense in the financial statements for lobbying which is removed along with the income tax associated with that expense. In addition to the adjustments to remove non-utility activity, there are also adjustments that are made to the Commission B Form A and Form B financial statements for ratemaking purposes. An example of these ratemaking adjustments is changes to payroll expenses for known increases/decreases in the expense relative to the expense reported on the Commission B Form A and Form B. After these adjustments are made, a further adjustment is made to the income and expense to allocate it to the customers within the respective regulatory jurisdiction to which the filing is being made.

Per Commission B's guidance in Opinion, Taxpayer asserts that the income tax allowance in ratemaking should reflect the tax the utility would pay on the basis of its

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projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. Taxpayer asserts this ratemaking aligns with the consistency requirement set forth in § 168(i)(9) such that any projections of tax expense, depreciation expense, rate base and the deferred tax reserve remain in synch. Taxpayer believes that setting rates based on the unadjusted Commission B financial statements would violate the consistency requirement of the normalization rules.

Taxpayer and the intervenors in the case entered into a Joint Stipulation and Settlement Agreement (the "Settlement"). Pursuant to the terms of the Settlement, the stipulating parties agreed that the NOLC DTA will be excluded from ADFIT and treated as cost free capital for purposes of the base rate revenue requirement resulting from the rate case. Instead, the stipulating parties would request the Commission A allow that amount to be deferred as a regulatory asset until rates are effective in Taxpayer's next base rate case. If Taxpayer obtains a PLR concluding that excluding Taxpayer's stand-alone NOLC DTA from ADFIT treated as cost free capital would constitute a normalization violation, Taxpayer will initiate a limited proceeding to update Taxpayer's Tax Rider to reflect the NOLC adjustments, along with any Commission A-approved offsets, in rates on an ongoing basis and to recover the regulatory asset. Taxpayer is seeking this private letter ruling in accordance with the terms of the Settlement.

#### RULINGS REQUESTED

Taxpayer requests the following rulings:

1. Reducing Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments as an offset to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments would result in Taxpayer losing its right to claim accelerated depreciation on all of its State public utility property.

#### LAW & 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.

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.

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Prior to The Revenue Reconciliation Act of 1990, the definition of public utility property was contained in § 167(l)(3)(A) and that definition is essentially unchanged in § 168(i)(10) and the regulations promulgated under former § 167(l) remain valid for application of the normalization rules.

In order to use a normalization method of accounting, § 168(i)(9)(A) of the Code requires that a 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 (hereinafter 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.

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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 tax 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

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amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Rev. Proc. 2020-39 provides guidance concerning the implementation of the EDIT normalization rules of TCJA § 13001 solely with respect to effects of tax rate reductions on timing differences related to accelerated depreciation. Sec. 4.01(6) of Rev. Proc. 2020-39 allows taxpayers that have amortized their EDIT in a manner not in accordance with the Revenue Procedure to prospectively correct the erroneous method at the next available opportunity. Taxpayers so correcting the erroneous method at such time and in such manner will not be treated as having violated the normalization rules of the TCJA.

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. 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. The deferred tax computation rules involve the method and life differences between book and tax depreciation and the statutory tax rate. In regard to request (1), Commission A's proposal to reduce Taxpayer's stand-alone DTA by reason of the TAA payments would introduce a variable, that is, the profits of affiliates and/or the TAA payments, other than the method and life differences between book and tax depreciation and the statutory tax rate.

Section 168(i)(9)(B)(ii) provides that the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii) does not comply with the Consistency Rule 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. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its rate base by removing used and useful assets) without making similar adjustments to book and tax depreciation expense, tax expense, and the reserve for deferred taxes.

Taxpayer and Staff generally agreed that the proper treatment of Taxpayer's EDIT should be determined in the same manner as the resolution of the DTA issue. In regard to request (2), based on the response to request (1), Taxpayer's amortization of its EDIT must take into account the \$f related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized.

In the setting of utility rates, a utility's rate base is offset by its EDIT and/or ADIT balance. Taxpayer maintains that the amortization of its EDIT must take into account the \$f related to the separate return NOLC DTA as a reduction to the total EDIT available to be amortized. The EDIT should be reduced because these are the amounts that did not actually defer tax due to the presence of the NOLC, as

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represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers.

In regard to request (3), Taxpayer sought to correct such treatment prospectively in the current GRC, the "next available opportunity," pursuant to Section 4.01(6) of Rev. Proc. 2020-39. Our understanding is that Commission A is in agreement to follow the outcome of the letter ruling request.

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By reducing Taxpayer's stand-alone DTA by reason of the TAA payments (or achieving a similar result through other methods), this improperly involves amounts that did not actually defer tax due to the presence of the NOLC, as represented in the DTA account. If the EDIT is not reduced, this results in an inappropriate flow-through of tax benefits to ratepayers

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. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

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Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because Commission A, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule or the deferred tax reserve computational rules constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

We are not providing a ruling on the overall merits of Commission A's policies towards separate return or consolidated return ratemaking. This ruling is solely with respect to the four normalization elements relevant to depreciation-related ratemaking. The treatment of non-ratemaking related payments as part of a TAA does not determine the normalization consequences of those arrangements. Ultimately, since depreciation normalization is based upon the construct of the extension of an interest free loan from the federal government to the utility in the form of deferred taxes, whether and how the group members allocate tax liabilities amongst themselves is irrelevant to the analysis. While under certain circumstances, the intercompany payments under a TAA might create an imputed loan between members, that is not a loan from the federal government, which is the *sine qua non* of depreciation normalization.

#### RULINGS

We rule as follows in response to Taxpayer's requested rulings:

1. Reducing Taxpayer's stand-alone DTA by reason of the TAA payments would violate the deferred tax reserve computational rules of § 1.167(l)-1(h)(2).
2. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments as an offset to the total EDIT available to be amortized, would constitute a violation of the normalization requirements of TCJA section 13001.
3. Reducing Taxpayer's standalone NOLC DTA by reason of the TAA payments would result in Taxpayer losing its right to claim accelerated depreciation on all of its State public utility property. However, as described this disallowance of Taxpayer's right to claim accelerated depreciation would only occur under facts not present in this case.

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.



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The rulings contained in this letter are based upon information and representations submitted by the taxpayer and accompanied by a penalty of perjury statement 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 representative.

This letter is being issued electronically in accordance with Rev. Proc. 2020-29, 2020-21 I.R.B. 859. A paper copy will not be mailed to Taxpayer.

Sincerely,

Patrick S. Kirwan

Digitally signed by Patrick S.  
Kirwan  
Date: 2024.03.08 14:16:15 -05'00'

Patrick S. Kirwan  
Chief, Branch 6  
Office of the Associate Chief Counsel  
(Passthroughs and Special Industries)

Enclosure: Copy for § 6110 purposes

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**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 Certain Regulatory And Accounting     )  
Treatments; and (4) All Other Required Approvals     )  
And Relief                                                         )

Case No. 2025-00257

**DIRECT TESTIMONY OF**  
  
**ANDREW R. CARLIN**  
  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
ANDREW R. CARLIN, ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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## **EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT ARC-1	Compensation Survey List
EXHIBIT ARC-2	Target Total Cash Compensation (“Target TCC”) vs. Market for Physical and Craft Positions
EXHIBIT ARC-3	Target TCC vs. Market for Nonexempt Salaried Positions
EXHIBIT ARC-4	Target TCC vs. Market for Exempt Non-Officer Positions
EXHIBIT ARC-5	Target TCC and Target Total Compensation (“Target TC”) vs. Market for Officer Positions
EXHIBIT ARC-6	2025 Short-Term Incentive Measures for Kentucky Power
EXHIBIT ARC-7	2025 AEP Scorecard for Short-Term Incentive Funding
EXHIBIT ARC-8	2025 Health and Welfare Benefit Summary
EXHIBIT ARC-9	2025 Employer and Employee Contribution Rates
CONFIDENTIAL EXHIBIT ARC-10	2025 Aon Benefit Index
CONFIDENTIAL EXHIBIT ARC-11	2025 Willis Towers Watson Healthcare Financial Benchmark Survey

**DIRECT TESTIMONY OF  
ANDREW R. CARLIN ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.     My name is Andrew R. Carlin and I am the Director of Compensation & Executive  
3           Benefits for American Electric Power Service Corporation (“AEPSC”). My business  
4           address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly owned  
5           subsidiary of American Electric Power Company, Inc. (“AEP”), the parent Company  
6           of Kentucky Power Company (“Kentucky Power” or the “Company”).

**II. BACKGROUND**

7   **Q.     PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
8           **BUSINESS EXPERIENCE.**

9   A.     I received a Bachelor of Arts Degree from Bowdoin College in 1988 with majors in  
10          both Economics and Government. I also received a Master of Business Administration  
11          Degree from the J. L. Kellogg Graduate School of Management at Northwestern  
12          University in 1992, with concentrations in finance, management strategy, and  
13          accounting.

14                 From 1987 to 1988, I worked for Putnam Investor Services as a Shareholder  
15          Services Representative. From 1988 to 1990 and in the summer of 1991, I worked as  
16          an Associate Consultant and Research Analyst in the U.S. Compensation Practice of

1 William M. Mercer, a leading international human resource consulting firm. From 1992  
2 to 2000, I worked for Bank One Corporation, now J.P. Morgan Chase, in multiple  
3 planning, finance and compensation capacities.

4 I joined American Electric Power Service Corporation (“AEPSC”) as the  
5 Director of Executive Compensation & Benefits in 2000. In 2002, my role was  
6 expanded to include responsibility for employee compensation in addition to executive  
7 compensation and benefits.

8 **Q. BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS**  
9 **DIRECTOR OF COMPENSATION AND EXECUTIVE BENEFITS.**

10 A. With assistance from other members of the Total Rewards<sup>1</sup> department and oversight  
11 from AEP management, I am primarily responsible for designing and administering  
12 compensation and executive benefits programs that attract, engage, motivate, and retain  
13 employees with the skills and experience needed to provide service to customers  
14 effectively, efficiently, and safely. These programs are components of a Total Rewards  
15 program that is designed to be reasonable in total cost, as compared to other similar  
16 companies, and market-competitive to attract and retain suitable employees. The Total  
17 Rewards team conducts ongoing research and recommends changes to compensation  
18 and benefit programs to maintain compensation and benefits at reasonable, prudent,  
19 and market competitive levels to achieve these objectives. The Total Rewards team  
20 also either administers these programs or oversees the third-party administrators,  
21 develops communications materials in support of compensation and benefit programs

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<sup>1</sup> “Total Rewards” generally is the value that employees derive from their work, including compensation, benefits, training, development, and recognition.

1 and maintains compliance with federal and state regulations related to compensation  
2 and benefits.

3 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE**  
4 **COMMISSION OF KENTUCKY?**

5 A. Yes. I have testified in person or submitted written testimony in many regulatory  
6 proceedings in various jurisdictions on behalf of AEP's operating companies, including  
7 case numbers 2009-00459, 2013-00197, 2014-00396, 2017-00179, 2020-00174, and  
8 2023-000159 before the Public Service Commission of Kentucky ("Commission") on  
9 behalf of Kentucky Power. My previous testimony was focused on employee  
10 compensation and benefits.

### **III. PURPOSE OF TESTIMONY**

11 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
12 **PROCEEDING?**

13 A. The purpose of my Direct Testimony is to describe the Kentucky Power's and AEP  
14 System's total compensation, including its rational and the amounts that the Company  
15 is seeking to recover in this case. I present information that demonstrates that the AEP  
16 System's employee incentive programs are cost-reasonable and in the best interests of  
17 customers. My Direct Testimony will also show that short-term and long-term  
18 incentive compensation expense is essential to the Total Compensation package for  
19 attracting and retaining skilled employees, ensuring safe and reliable electric service  
20 for Kentucky Power customers.

21 **Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES?**

22 A. Yes. I am sponsoring the following Exhibits:



- Exhibit ARC-1 - Compensation Survey List
- Exhibit ARC-2 - Target Total Cash Compensation vs. Market for Technical, Craft and Clerical Positions
- Exhibit ARC-3 - Target Total Cash Compensation vs. Market for Nonexempt Salaried Positions
- Exhibit ARC-4 - Target Total Cash Compensation vs. Market for Exempt Positions
- Exhibit ARC-5 - Target Total Cash Compensation and Total Compensation vs. Market for Officer Positions
- Exhibit ARC-6 - 2025 Short-Term Incentive Measures for Kentucky Power
- Exhibit ARC-7 - 2025 AEP Scorecard for Short-Term Incentive Funding
- Exhibit ARC-8 - 2025 Health and Welfare Benefit Summary
- Exhibit ARC-9 - 2025 Employer and Employee Contribution Rates
- Confidential Exhibit ARC-10 - **Confidential** 2025 Aon Benefit Index
- Confidential Exhibit ARC-11 - **Confidential** 2025 Willis Towers Watson Healthcare Financial Benchmark Survey

**Q. WHAT ARE THE COMPENSATION TERMS USED IN THIS TESTIMONY?**

A. The Company compensates all regulated employees, except co-op students and interns, with a combination of a fixed base wage or salary (“Base Pay”) and a variable or short-term incentive (“STI”) compensation opportunity. I refer to the sum of these two types of compensation (Base Pay + STI) as Total Cash Compensation (“TCC”).

Approximately 1,350 AEP positions out of approximately 16,780 also have a regular annual long-term incentive (“LTI”) compensation opportunity. These positions generally require unique skills and involve roles for which long-term continuity, prudence, and vision are required.

1           Total Compensation is comprised of Base Pay, STI compensation and, for  
2           eligible positions, LTI compensation: (Base Pay + STI + LTI = Total Compensation).  
3           I refer to the sum of STI and LTI, if applicable, collectively as Incentive Compensation.  
4           Total Compensation and TCC are the same for employees in positions that do not have  
5           a regular annual LTI opportunity.

6           I refer to the target value of Incentive Compensation as Target STI, Target LTI,  
7           or collectively as Target Incentive Compensation. When target values of Incentive  
8           Compensation are combined with Base Pay, I refer to these values as Target TCC  
9           (Base Pay + Target STI = Target TCC) or Target Total Compensation (Base Pay +  
10          Target STI + Target LTI = Target Total Compensation).

#### IV. EXECUTIVE SUMMARY

11   **Q.   PLEASE GENERALLY DESCRIBE THE COMPANY’S REQUESTED**  
12   **ADJUSTMENT WITH RESPECT TO COMPENSATION IN THIS**  
13   **PROCEEDING.**

14   A.   The Company is requesting inclusion of the target level of direct Kentucky Power  
15   Company and indirect Wheeling Power Company annual or short-term incentive  
16   (“STI”) compensation of \$1,761,459 and long-term incentive (“LTI”) compensation of  
17   \$207,954 in cost-of-service. The indirect STI and LTI allocated from Wheeling Power  
18   Company reflects Kentucky Power Company’s ownership share of the Mitchell  
19   generating plant. The requested target level of STI is an increase in cost from the actual  
20   levels of \$978,954 of STI expense and \$153,863 of LTI expense. The adjustment to  
21   increase the cost of this annual and long-term incentive compensation to the target level  
22   (W30) is supported by Company Witness Ciborek. The Company is also requesting

1 inclusion of the test-year amounts of indirect STI and LTI costs of AEPSC and other  
2 affiliates that were charged to Kentucky Power. Consistent with its historical practice,  
3 Kentucky Power is not requesting a similar adjustment to increase STI and LTI expense  
4 in cost-of-service for indirect AEPSC and other affiliate expense, even though these  
5 expenses have averaged significantly above the target level over the last five and 10  
6 years. The Company is also seeking to recovery of the test-year amount of employee  
7 benefits because they are reasonable and market competitive.

8 **Q. WHY DOES KENTUCKY POWER NEED TO PROVIDE**  
9 **MARKET-COMPETITIVE COMPENSATION AND BENEFITS?**

10 A. The Company faces unrelenting competition for employees with other utilities and  
11 utility contractors both within and outside its service territory, as well as with  
12 employers in other industries, such as construction and oil and gas. Offering  
13 competitive compensation and benefits is essential to attract and retain skilled  
14 employees who can deliver reliable, safe, efficient, and cost-effective electric service  
15 to Kentucky Power customers. This testimony demonstrates that the compensation and  
16 benefits the Company offers employees, inclusive of STI and LTI compensation, is  
17 customary, prudent, cost-reasonable, market competitive, and a benefit to customers.

18 **Q. WHAT IS THE COMPANY'S OVERALL APPROACH TO COMPENSATION?**

19 A. The Company's compensation and employee benefits are managed, with those of other  
20 AEP system companies (collectively, the "Companies"), within the context of labor  
21 market trends, to control employee labor and benefit expense for the benefit of both  
22 customers and shareholders. The Company's Base Pay increase budgets are generally  
23 established to match the expected market median for the upcoming year but are also

1 affected by budget constraints and labor negotiations. Actual market Base Pay  
2 increases may also be different than expected when the Company's budget is  
3 implemented, which may lead the Company to adjust its Base Pay increase budgets for  
4 either the current or subsequent year. For example, the Company accelerated Base Pay  
5 growth in 2022 and 2023 to address attraction, retention and labor negotiation issues  
6 caused, in part, by unexpected inflation in the cost of labor that resulted in the  
7 Company's Base Pay falling behind the market median.

8 There are certain disciplines for which market-competitive total compensation  
9 is increasing faster than for other positions, such as journey-level line mechanics, for  
10 which there has been a significant national shortage. Such labor supply shortages drive  
11 higher compensation growth rates for these roles at the Company and elsewhere.

12 **Q. DOES THE COMPANY'S SHORT-TERM INCENTIVE (STI)**  
13 **COMPENSATION PROVIDE SUBSTANTIAL BENEFITS TO CUSTOMERS?**

14 A. Yes. STI compensation benefits customers by helping the Company attract and keep  
15 skilled employees, ensuring efficient, effective, and safe customer service through  
16 market competitive Total Compensation. The ability to attract and retain such a  
17 workforce is essential to meeting customers' needs and doing so at a reasonable cost.  
18 This is because offering less than market competitive compensation increases  
19 employee turnover, position vacancy, and hiring and training costs, while reducing  
20 productivity. These impacts are likely to increase outage response time, decrease  
21 service levels, and increase the cost-of-service for customers. Because the target level  
22 of the Company's Incentive Compensation is a component of a reasonable and market  
23 competitive Total Compensation package, it provides these benefits without incurring

1 any incremental cost above the cost of providing market competitive compensation  
2 through Base Pay alone. Among many other benefits, STI compensation helps maintain  
3 higher levels of employee and Company performance than would be achieved using  
4 Base Pay alone, which benefits customers by completing work more efficiently and  
5 effectively and thereby comparatively reducing costs. The financial portion of  
6 short-term incentive compensation benefits customers by continuously emphasizing  
7 the importance of financial discipline and directly encouraging employees to maintain  
8 financial discipline, spend conservatively, operate efficiently, and conserve resources,  
9 which is essential for providing reliable service at a reasonable cost to customers.

10 **Q. DOES THE COMPANY'S LONG-TERM INCENTIVE (LTI)**  
11 **COMPENSATION PROVIDE SUBSTANTIAL BENEFITS TO CUSTOMERS?**

12 A. Yes. The Company's LTI compensation is similar to STI compensation in that it too  
13 is an integral component of cost-reasonable and market competitive Total  
14 Compensation for participants. In addition to the benefits mentioned above that STI  
15 compensation provides to customers, all of which also apply to LTI, LTI  
16 compensation helps retain experienced employees in key decision-making roles,  
17 ensuring consistent and efficient operations. This improves the continuity of the  
18 Company's operations and benefits customers by providing more efficient, effective,  
19 and consistent operations. Financial LTI measures also communicate that it is  
20 imperative to maintain financial discipline and strongly encourage its pursuit, which  
21 directly benefits customers by reducing the Company's cost-of-service and rates  
22 compared to what they would otherwise be. LTI also encourages a longer-term

1 decision-making perspective, which is particularly imperative given the expected long  
2 service life of the assets that comprise the Company's electric system.

## **V. OVERVIEW OF COMPENSATION PRACTICES**

3 **Q. PLEASE DESCRIBE THE VARIOUS TYPES OF EMPLOYEES THAT WORK**  
4 **FOR THE COMPANY AND HOW EACH TYPE OF EMPLOYEE IS**  
5 **COMPENSATED.**

6 A. The Company employs physical, craft, and technical employees, such as line  
7 mechanics and general servicers who are paid an hourly wage, with the potential for  
8 overtime and shift premiums, along with an STI opportunity. Wage increases for these  
9 employees primarily take the form of an annual general wage increase, that generally  
10 aligns with wage increases in the labor market. Non-annual wage increases may also  
11 be provided to address positions and functions for which attracting and retaining  
12 suitable employees is more difficult, wages that are below market-competitive levels,  
13 or to standardize wages with those of other AEP operating companies. AEPSC and the  
14 Company negotiate wage rates and increases for most physical, craft, and technical  
15 employees with labor unions as part of a collective bargaining process and agreement.  
16 Market compensation rates, the growth rate of wages, employee turnover in these  
17 positions, union bargaining positions, and the wages paid by competitors for these  
18 employees are considered in determining positions for labor negotiations. Collectively  
19 bargained rates are generally mirrored in setting wages for unrepresented physical,  
20 craft, and technical employees. As a result, the wages the Company offers to employees  
21 for both represented and unrepresented physical, craft, and technical positions  
22 generally track market-competitive compensation.

1           Physical, craft, and technical employees below the journey level also progress  
2 through job steps and job levels as they accumulate the experience and other  
3 qualifications needed to perform more demanding, dangerous, and challenging work  
4 safely. For example, Line Mechanics must complete the experience and other  
5 qualifications for Line Mechanic A Step 1, to progress from the top Line Mechanic B  
6 Step and begin receiving both the pay and work responsibilities associated with the  
7 higher Line Mechanic A Step 1 position.

8           The Company also employs non-exempt salaried employees as well as exempt  
9 professional, managerial, and executive employees. Employees in these types of  
10 positions participate in an annual performance review and merit pay program, along  
11 with the annual STI program. Some professional positions, many managerial positions,  
12 and all executive positions also participate in an LTI program. AEPSC's compensation  
13 team compares the compensation for these positions to market survey information to  
14 assign or reassign positions to salary grade levels and recommend compensation and  
15 other changes to maintain Total Compensation at reasonable and market-competitive  
16 levels.

17 **Q. WHY IS IT NECESSARY TO OFFER MARKET COMPETITIVE**  
18 **COMPENSATION AND BENEFITS AND WHAT WOULD BE THE**  
19 **CONSEQUENCES IF THE COMPANY DID NOT DO SO?**

20 A. Simply put, the Companies must offer market competitive compensation and benefits  
21 to attract and retain skilled employees, to ensure efficient and effective customer  
22 service. Kentucky Power and AEPSC compete with employers in nearly all industries,  
23 particularly the utility, energy services, and construction industries, depending on the

1 skill set and qualifications related to each occupation. By and large, current and  
2 prospective Kentucky Power employees have other employment options. Offering  
3 below-market compensation would lead to a decline in personnel quality due to attrition  
4 and hinder timely recruitment of suitable replacements unless compensation is  
5 increased. This would result in added costs for recruitment and training, as well as lost  
6 productivity during the period it takes new employees to become fully proficient in  
7 their new jobs. This would lead to higher costs and/or lower service quality for  
8 customers. These costs are likely to more than offset the cost saved from paying below  
9 market compensation.

10 **Q. DO THE COMPANIES HAVE COMPETITION FOR ATTRACTING AND**  
11 **RETAINING SUITABLE EMPLOYEES?**

12 A. Yes. The Companies compete for employees with other utilities and utility contractors  
13 both inside and outside of the service territory, as well as with employers in other  
14 industries, such as construction and oil and gas. Utility contractors perform roughly  
15 half of the Company's physical, craft, and technical work, and the contractors that  
16 perform this work compete with the Company, directly or indirectly, for suitable  
17 employees.

18 The market survey data in Exhibits ARC 2-5 show that, at the median,  
19 employers provide Incentive Compensation to nearly all positions offered within the  
20 Company and AEPSC for which survey data is available. I discuss this in more detail  
21 in the Competitiveness of Total Compensation section below. As a result, it is likely  
22 that most of the contract labor performing work for Kentucky Power Company and  
23 AEPSC receive Incentive Compensation.



1    **Q.     PLEASE DESCRIBE THE COMPANIES' APPROACH TO COMPENSATION**  
2           **IN ORDER TO ATTRACT AND RETAIN A WORK FORCE TO ENSURE**  
3           **SAFE AND RELIABLE SERVICE.**

4    A.     The Companies employ a Total Compensation approach to attracting and retaining  
5           employees to provide safe and reliable service to Kentucky Power's customers. As  
6           previously discussed, Total Compensation is comprised of Base Pay, STI compensation  
7           and, for eligible positions, LTI compensation. When combined with Base Pay, the  
8           target value of STI is designed to bring employee Total Compensation to a  
9           market-competitive and reasonable level. Therefore, the target value of Incentive  
10          Compensation is a critical component of the market-competitive Total Compensation  
11          package that the Companies depend on to help attract and retain qualified employees.

12   **Q.     WHAT ARE THE OBJECTIVES OF THE COMPANIES' TOTAL**  
13          **COMPENSATION PROGRAM?**

14   A.     The primary objective of the Companies' Total Compensation program is to attract and  
15          retain skilled employees to ensure efficient, effective, and safe customer service,  
16          providing clear benefits to customers. The Companies' compensation is managed by  
17          the AEPSC compensation team and Company management, in a manner that is based  
18          on labor market trends, business needs, labor negotiations, employee turnover and  
19          hiring trends, among other factors. The compensation strategy for achieving this  
20          objective is to provide a Total Compensation opportunity that is, on average, at the  
21          median of the Total Compensation opportunities provided for similar positions in the  
22          labor market. Focusing on Total Compensation opportunity, rather than Base Pay

1 alone, is the correct methodology for compensation comparisons because only Total  
2 Compensation takes all statistically significant types of compensation into account.

3 **Q. WHY IS TOTAL COMPENSATION CHOSEN AS THE PRIMARY POINT OF**  
4 **COMPARISON RATHER THAN BASE SALARY?**

5 A. As with most large employers, we find that providing a market-competitive Total  
6 Compensation package to employees is an efficient and effective strategy because it  
7 allows the Company to attract and retain the suitably skilled and experienced  
8 employees needed to provide service to customers without either paying above median  
9 Total Compensation or creating excessive position turnover and vacancy. As part and  
10 parcel of a reasonable, customary, and market competitive Total Compensation, the  
11 Company provides variable Incentive Compensation to motivate and encourage  
12 employees to control costs, improve customer service, and work safely, among other  
13 reasons. As such, the variable Incentive Compensation portion of Total Compensation  
14 is the amount the Company and AEPSC would need to provide as Base Pay if variable  
15 Incentive Compensation were not offered. This also has the advantage, compared to  
16 fixed Base Pay, of encouraging employees to improve their performance, which  
17 collectively results in improved Company performance and better service rendered to  
18 customers. Including variable Incentive Compensation in the Total Compensation mix  
19 allows operational goals to be communicated more effectively, aligns employee efforts  
20 with these goals, encourages goal achievement, and bolsters the development of a  
21 high-performance culture, all without increasing compensation expense.

22 Because the use of Incentive Compensation fosters a better performing  
23 workforce than Base Pay alone, we believe that a blend of these two types of

1 compensation is the most cost efficient and effective compensation strategy for  
2 providing reliable electric service to customers. Because most prospective employees  
3 believe they will succeed in and benefit from an incentive compensation opportunity,  
4 this approach also better enables the Company to compete in the labor market to attract,  
5 retain and engage employees. Furthermore, companies that provide incentive also are  
6 more likely to attract, retain and engage higher performing employees because such  
7 employees are more likely to choose an employer that they believe will reward them  
8 for their higher performance. The benefits provided by variable Incentive  
9 Compensation (better operational performance, improved teamwork, and reduced cost,  
10 among other benefits) reduce the Company's cost of providing electric service, which  
11 directly benefits customers.

12 Total Compensation is an effective compensation tool because it includes all  
13 statistically significant types of employee compensation that serve the aforementioned  
14 objectives. Only with the inclusion of the variable incentive portion does the  
15 Company's and AEPSC's Total Compensation reach the market-competitive range in  
16 many cases. Moreover, survey information shows definitively that STI compensation  
17 is a statistically significant component of market-competitive compensation for nearly  
18 all the Company's and AEPSC's positions. Likewise, survey information shows that  
19 LTI compensation is a significant and often substantial component of market  
20 competitive compensation for those positions that annually participate in AEP's LTI  
21 program. Therefore, any assessment of market competitive compensation for the  
22 Company's and AEPSC's positions that does not include both types of incentive  
23 compensation would be invalid.

1           In addition, because the AEPSC compensation team considers the value of  
2           Incentive Compensation provided by the market in assigning job grades to positions,  
3           the Company's Base Pay levels are typically lower than employers that provide less or  
4           no Incentive Compensation opportunity. Because the mix of Base Pay, STI, and LTI in  
5           Total Compensation can vary significantly across employers, any compensation  
6           analysis that does not consider Incentive Compensation is incomplete.

7   **Q.   HOW DO YOU DETERMINE THAT TOTAL COMPENSATION LEVELS**  
8   **ARE REASONABLE AND MARKET-COMPETITIVE?**

9   A.   The AEPSC compensation team compares the Companies' compensation levels and  
10       practices to those of similar employers for similar positions to ensure that they are  
11       reasonable and market competitive. As discussed in more detail in Section VII of my  
12       Direct Testimony, the AEPSC compensation team relies on third-party compensation  
13       surveys that provide robust market compensation benchmarks based on statistically  
14       sound survey methodologies, including extensive and independently verified  
15       compensation information for statistically significant samples of incumbents in a wide  
16       variety of job.

17   **Q.   DOES THE USE OF MARKET MEDIAN AS THE COMPANY'S AND**  
18   **AEPSC'S PRIMARY COMPENSATION BENCHMARK IMPLY THAT**  
19   **EMPLOYEE COMPENSATION WILL GENERALLY BE AT THE MEDIAN?**

20   A.   Not necessarily. First, variances in job requirements, employer pay practices, and  
21       locational differences create a range of market compensation rates; therefore,  
22       compensation practices are designed to deliver compensation that is within a  
23       market-competitive range around the market median. The Companies' salary ranges

1 for each salary grade extend approximately 22.5% above and below the midpoint, to  
2 reflect the range of compensation for positions in the labor market. Salaries for  
3 individual employees may fall anywhere within the assigned range depending on  
4 individual experience, qualifications, performance, time in job, and other factors.  
5 Furthermore, the employers that participate in compensation surveys, the incumbents  
6 in the jobs reported in those surveys, and the compensation for these incumbent  
7 employees are all constantly changing so it is not possible to precisely set compensation  
8 levels given this constantly moving target.

9 **Q. DOES THE TARGET LEVEL OF INCENTIVE COMPENSATION**  
10 **CONTRIBUTE TO A TOTAL COMPENSATION OPPORTUNITY THAT**  
11 **EXCEEDS THE MARKET-COMPETITIVE RANGE OR A**  
12 **COST-REASONABLE LEVEL?**

13 A. No. Unlike “bonus” type incentive plans, the Company’s and AEPSC’s target  
14 level for Incentive Compensation ensures Total Compensation remains within  
15 market-competitive standards. The target level of Incentive Compensation is a portion  
16 of a market-competitive and cost-reasonable Total Compensation package that is at risk  
17 to encourage high employee performance and the achievement of performance goals  
18 and objectives.

19 **Q. WHAT IS THE COMPANY SEEKING TO RECOVER IN THIS CASE?**

20 A. In addition to the annualized labor cost adjustments discussed by Company Witness  
21 Ciborek, the Company is seeking to recover the Total Compensation (including Base  
22 Pay, STI, and LTI) and the Company benefits package that is necessary to attract and  
23 retain the workforce necessary to provide safe and reliable service. Specifically, the

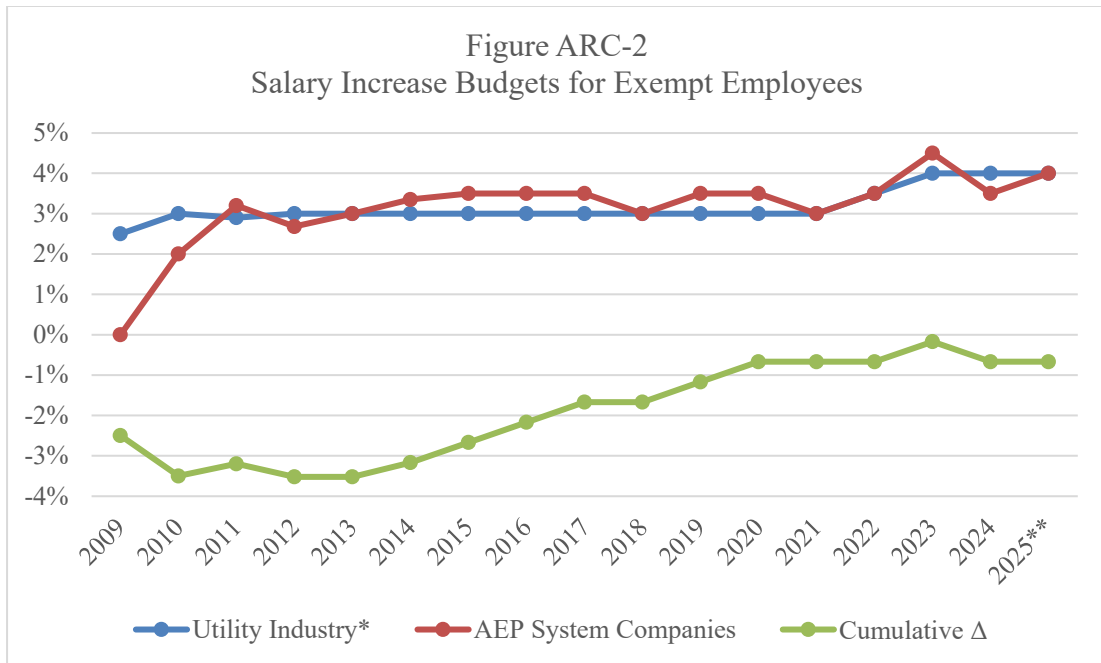
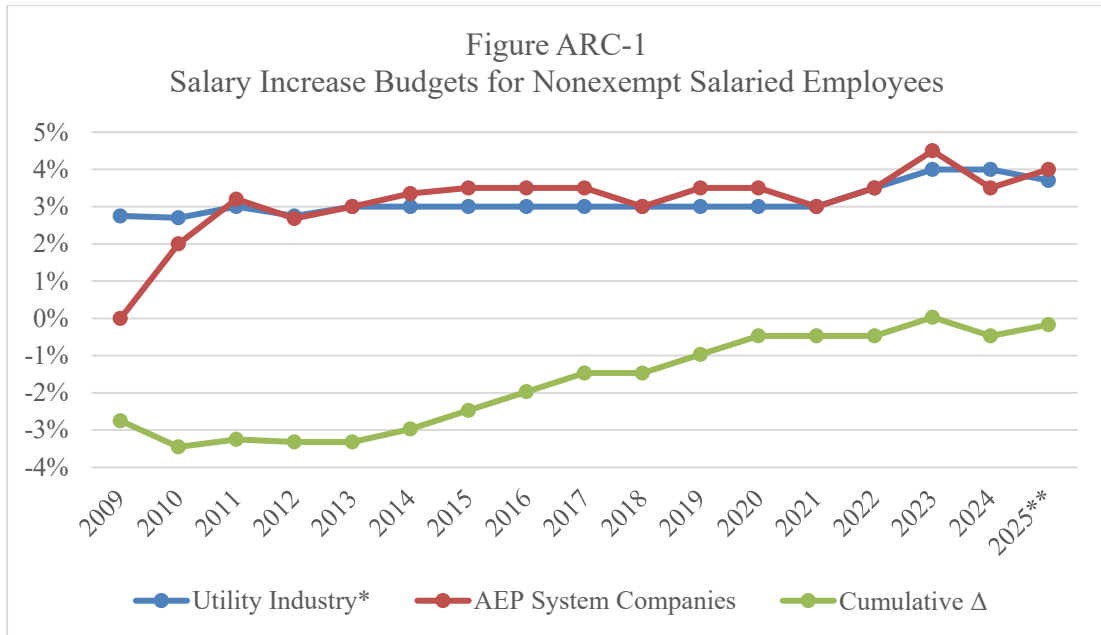
1 Company is requesting that the target portion of the direct cost of Kentucky Power  
2 Company STI and the allocated ownership share of the Mitchell Plant STI for the test  
3 year be included in the Company's cost-of-service, rather than the actual cost, which is  
4 lower. The adjustment to increase short-term and long-term incentive compensation  
5 expenses to the target level (W30) is supported by Company Witness Ciborek. The  
6 Company is also requesting inclusion of the test-year amounts of indirect STI and LTI  
7 costs of AEPSC and other affiliates that were charged to Kentucky Power. Consistent  
8 with its historical practice, the Company is not requesting a similar adjustment for  
9 indirect AEPSC and other affiliate STI and LTI costs, which would also increase the  
10 cost-of-service even though these costs have averaged 117% and 136% of target over  
11 the last five and 10 years, respectively. Finally, the Company is seeking to recovery of  
12 the employee benefits because they are reasonable and market competitive.

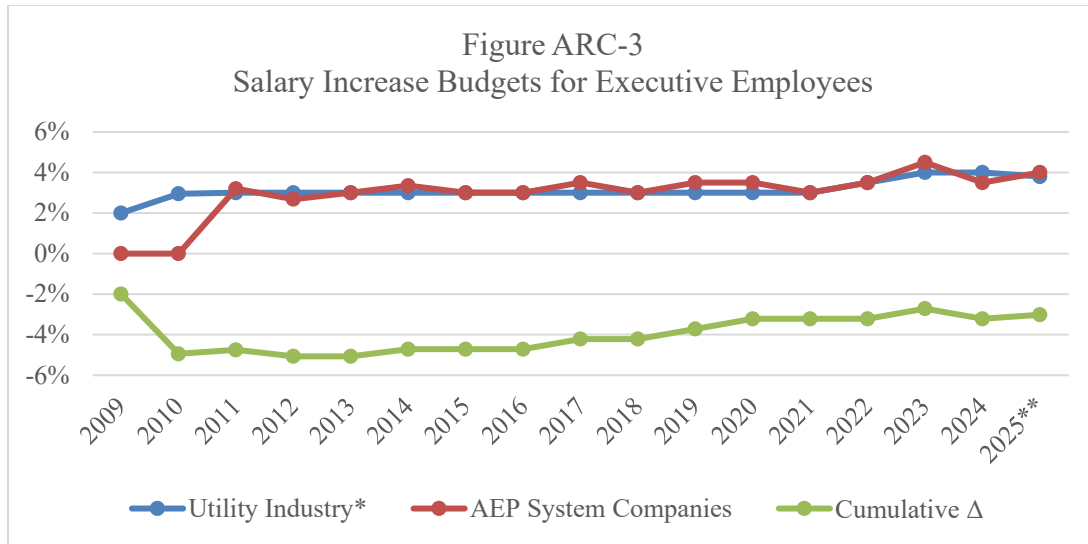
**VI. ACTIONS TO CONTROL COMPENSATION EXPENSE**

**13 Q. HOW HAVE BASE PAY INCREASES COMPARED TO THOSE OF OTHER  
14 UTILITY INDUSTRY EMPLOYERS?**

15 A. The Company's and AEPSC's total Base Pay increases for salaried positions lagged  
16 the market median rate of Base Pay increases over the period 2009 through 2025,  
17 particularly for executive positions, as Figures ARC-1 through ARC-3 below  
18 demonstrate. This lag is primarily the result of a salary freeze for most positions in  
19 2009 and for executive positions in 2009 and 2010 that was implemented in response  
20 to the Great Recession that began in 2008. Figures ARC-1 through ARC-3 below  
21 compare salary increase budgets for Kentucky Power and other AEP system companies

- 1 to median utility industry Base Pay increase budgets for nonexempt salaried, exempt,
- 2 and executive employees for the years 2009 through 2025 (projected).





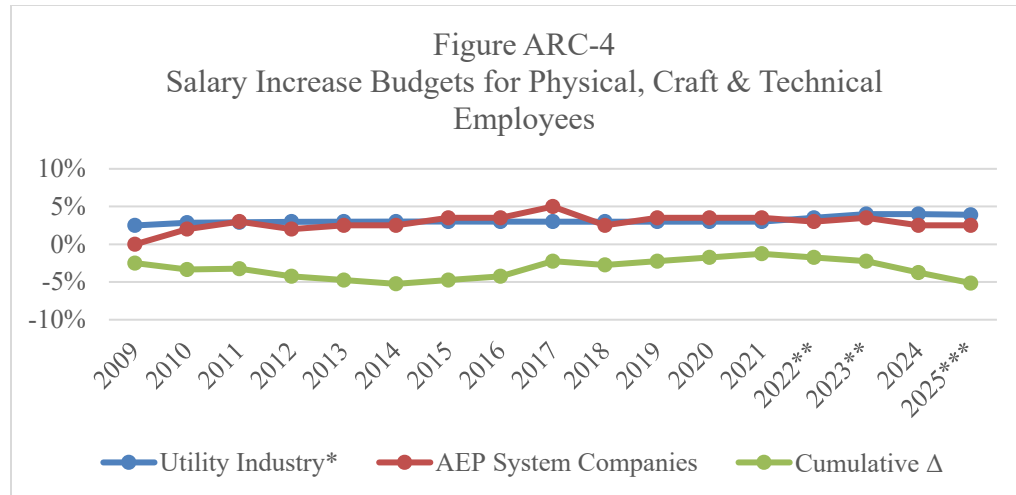
\* The Conference Board Research Report, U.S. Salary Increase Budgets for 2009–2025, actual market median total increase budgets vs. the actual increase budgets for the AEP system companies.

\*\* The Conference Board projected 2025 market median vs. the Company's actual 2025 salary increase budget, which includes a 3.00% merit budget and an additional 1.00% budget line of progression promotions and equity adjustments.

Figures ARC-1 through ARC-3 show that the salary increases provided by Kentucky Power and other AEP system companies to salaried employees were generally aligned with market wage increases over this period. These figures also show that the salaries for Kentucky Power and other AEP system companies grew by less than market rates early in this period and, therefore, lagged the market more significantly on a cumulative basis for much of this period, which is a savings passed on to Kentucky Power customers in rates.

For hourly physical, craft, and technical employees, Base Pay increases also lagged the market during the 2009–2025 period. Figure ARC-4 below shows that for the period 2009 through 2025, the general Base Pay increases for hourly physical, craft, and technical positions, Kentucky Power and other AEP system employees lagged the market median by 5.65%.





\* The Conference Board Research Report, U.S. Salary Increase Budgets for 2010–2024 actual market median total increase budgets vs. the actual increase budgets for the AEP system companies.

\*\*There were additional 2022–2023 wage increases for some physical and craft employees, which are described in the following two paragraphs below.

\*\*\* The Conference Board projected 2025 market median vs. the Company's actual 2025 wage increase budget.

1    **Q.    HOW HAS THE COMPANY RESPONDED TO CHANGING LABOR**  
2    **MARKET DEMANDS IN RECENT YEARS?**

3    A.    Effective January 1, 2022, as collectively bargained or as determined by AEPSC  
4    management, the Company and other AEP affiliates implemented a 2.0% shift of STI  
5    compensation to base wages for physical and craft positions. This reduced incentive  
6    targets for most of these positions by 2.0% of Base Pay (from 5% to 3% of base wages)  
7    and increased Base Pay rates by the same 2.0%. This change in compensation mix was  
8    approximately cost neutral at the target level of incentive compensation, and it is  
9    therefore not included in Figure ARC-4 above.

10            In reaction to a tightening labor market and difficulty retaining and attracting  
11    employees qualified for certain journey-level skilled jobs, effective January 1, 2022,  
12    the Company and other AEP affiliates also provided an additional 1.0% Base Pay

1 increase for journey-level line workers and reduced the number of steps required to  
2 obtain the journey level. Then, effective October 1, 2022, in reaction to a tightening  
3 labor market and difficulty retaining and attracting employees qualified for certain  
4 journey-level skilled jobs, the Company and other AEP affiliates increased wages for  
5 journey-level distribution line, transmission line, transmission station, and network  
6 jobs by approximately 7.5% and increased wages for journey-level protection & control  
7 and meter jobs by approximately 4.5%. The Company accelerated Base Pay growth in  
8 2022 and 2023 to address attraction and retention issues. However, this did not  
9 significantly raise the Company's compensation compared to market-competitive  
10 levels due to ongoing labor market inflation. This is because of the increased rate of  
11 labor market inflation in 2022 that has continued through the present day.

12 **Q. DID THE COMPANIES IMPLEMENT SALARY AND WAGE INCREASES**  
13 **FOR ALL CLASSES OF EMPLOYEES IN 2025?**

14 A. Yes. For those employees who participate in the merit program, a 4.00% total salary  
15 increase budget was implemented effective April 1, 2025, which consisted of a 3.00%  
16 merit budget, and a 1.00% line of progress promotion and equity adjustment budget.  
17 The Companies also implemented a previously negotiated 2.5% general wage increase  
18 for 2025 for non-salaried physical and craft employees. This general wage increase also  
19 applied to all unrepresented physical and craft employees and is effective on the  
20 anniversary of collective bargaining agreements or wage increases throughout 2025.

**VII. COMPETITIVENESS OF TOTAL COMPENSATION**

**Q. HOW DO THE COMPANIES DETERMINE THAT TOTAL COMPENSATION LEVELS ARE REASONABLE AND MARKET COMPETITIVE?**

A. The Companies evaluate their compensation levels by comparing them with those of similar employers for similar positions, ensuring they remain reasonable and competitive in the market. This is primarily done using third-party compensation surveys that the compensation department participates in and purchases each year. These surveys provide robust market compensation benchmarks based on statistically sound survey methodologies. Positions that are generally specific to the energy services industry, such as line mechanic, are benchmarked relative to similar positions in the U.S. energy services industry. Positions found more broadly, such as administrative assistant, are benchmarked relative to similar positions in U.S. general industry. These surveys provide extensive, independently verified, and statistically sound compensation information for statistically significant samples of incumbents in a wide variety of jobs.

To make these comparisons, the Companies' positions are matched to those in these surveys based on the jobs function, specialty, level, and other factors. The Companies' compensation levels and practices are then compared to the survey sample of market competitive compensation for the matched jobs. After accounting for any material differences in position scope, the compensation department uses market median Total Compensation as the primary compensation benchmark for each job. Base Pay and Target TCC, which are components of Target Total Compensation, are used as additional points of comparison. Each merit pay eligible job is then assigned to

1 a salary grade with an associated salary range, STI target, and LTI target, when  
2 applicable. Grades are assigned to provide market competitive compensation as well as  
3 a smooth grade progression for job families and internal equity across job families.  
4 This process is also used to periodically review and update compensation rates, salary  
5 grades, incentive targets, and other compensation practices to maintain competitive  
6 compensation for each position. This process is widely recognized as an effective  
7 method for managing compensation and is generally consistent with the practices of  
8 most electric utilities and major U.S. companies. The surveys completed and used in  
9 this process during the test year are listed in Company Exhibit ARC-1 (Compensation  
10 Survey List).

11 **Q. HOW SHOULD THE COMPETITIVENESS OF THE COMPANY'S**  
12 **COMPENSATION BE ASSESSED?**

13 A. All statistically significant forms of compensation should be considered in any analysis  
14 of compensation competitiveness. Incentive Compensation is a statistically significant  
15 form of compensation for all Kentucky Power and other AEP system positions;  
16 therefore, it should be included in any such analysis. Kentucky Power and other AEP  
17 system companies compete for employees with a great many other employers, a large  
18 majority of which offer Incentive Compensation to those employees. The Commission  
19 should assess if Total Compensation, including Incentive Compensation, is both cost  
20 reasonable and competitive in the market because competitive compensation is crucial  
21 for attracting and retaining skilled employees who ensure reliable and efficient electric  
22 services, while keeping costs low.

1           Although reducing Total Compensation to less than the market-competitive  
2 range would reduce compensation expenses, this cost reduction likely would be more  
3 than offset by:

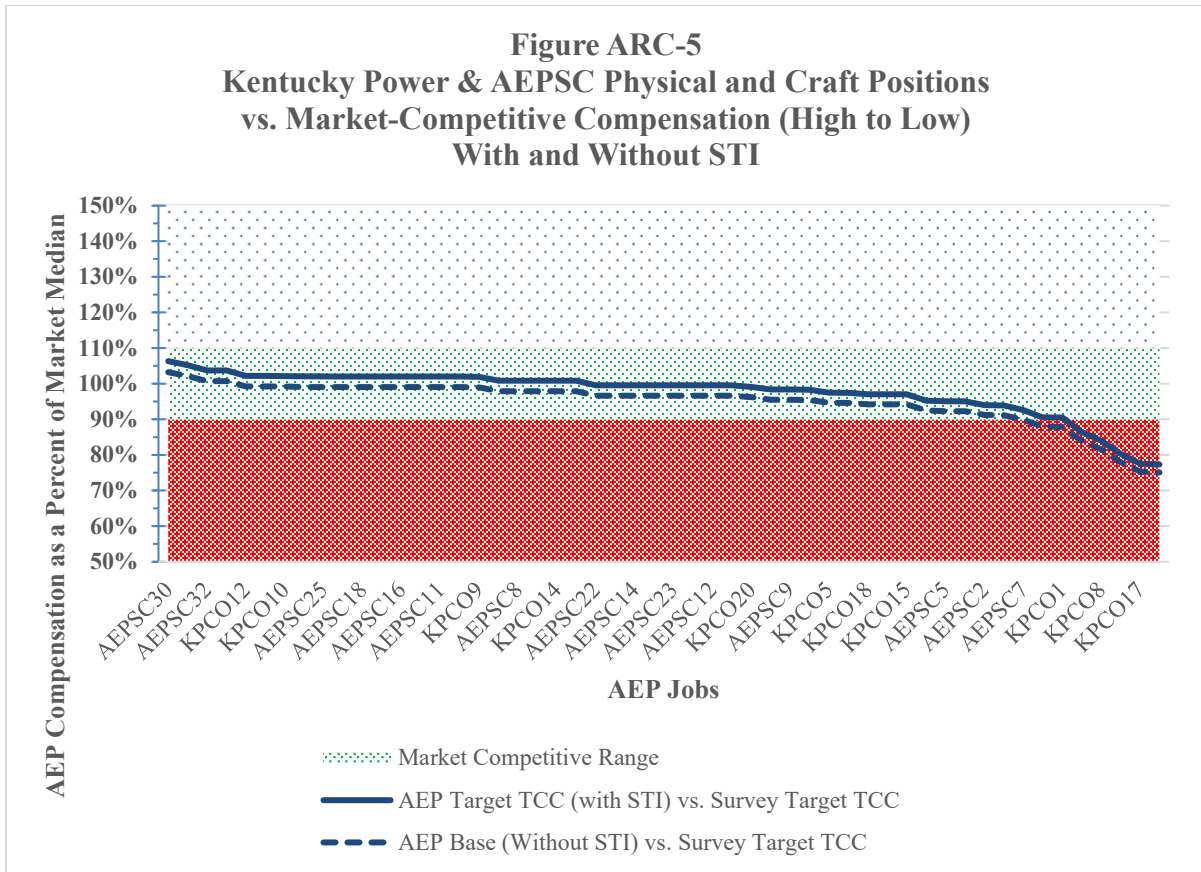
- 4           1. Increased position vacancy, which reduces effectiveness and the ability of the  
5           Company to safely and reliably serve its customers.
- 6           2. Increased hiring and training expenses due to increased employee turnover.
- 7           3. Lower employee productivity, given the many years it often takes new  
8           employees to learn to perform their jobs safely, efficiently, and effectively.

9           This is particularly true for positions that require lengthy apprenticeships or  
10 training periods to learn the skills needed to work independently and safely, such as the  
11 lineman job family. In addition, it generally takes around three months to fill vacant  
12 positions and much longer for new employees to come up to speed on new duties, work  
13 processes and safety procedures. This lost and reduced productivity often must be  
14 backfilled by employees who are less efficient at this work, such as employees who  
15 normally perform other duties, or who are more expensive, such as the vacant position's  
16 supervisor. Employee turnover gives rise to many other incremental costs beyond the  
17 examples cited above. The incremental cost to customers of reduced service quality  
18 that results from increased vacancy as well as the increased hiring and training expense  
19 due to higher employee turnover are the primary reasons that the provision of  
20 market-competitive Total Compensation benefits Kentucky Power customers.

1   **Q.   HOW DOES TARGET TOTAL COMPENSATION FOR HOURLY**  
2       **PHYSICAL, CRAFT, AND TECHNICAL POSITIONS COMPARE WITH**  
3       **MARKET DATA?**

4   A.   As shown in Figure ARC-5 below, which graphs the market compensation comparisons  
5       provided in Exhibit ARC-2, Kentucky Power's and AEPSC's average target TCC for  
6       258 hourly physical, craft, and technical positions in 52 different Kentucky Power and  
7       AEPSC jobs was 2.3% below the market median as of May 31, 2025. This is near the  
8       middle of a market-competitive compensation range of +/- 10% of the survey median,  
9       which is typical practice for such positions. This shows Kentucky Power and AEPSC's  
10      average target TCC for these positions is cost-reasonable and market-competitive.

11               However, Figure ARC-5 also shows that if STI were excluded (*i.e.*, comparing  
12      the Company's and AEPSC's Base Pay to market TCC), then average compensation  
13      would be 5.2% below the market median. While this average is still within the market  
14      competitive range, 15.4% of these positions fall below this range, posing challenges in  
15      timely attracting and retaining qualified employees.



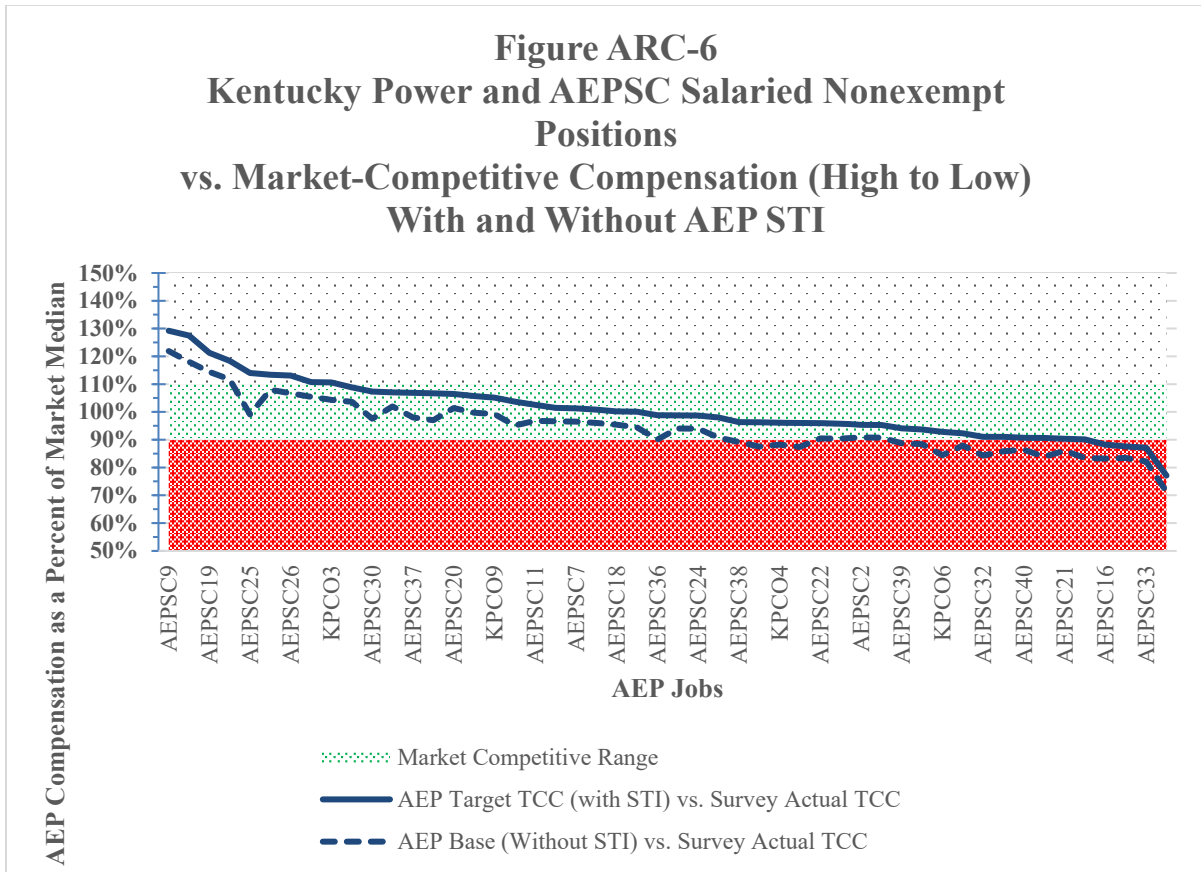
1 **Q. ARE THERE DISCIPLINES FOR WHICH MARKET-COMPETITIVE TOTAL**  
 2 **COMPENSATION IS INCREASING FASTER THAN FOR OTHER**  
 3 **POSITIONS?**

4 A. Yes. There is a significant shortage of journey-level line mechanics; therefore,  
 5 compensation is increasing accordingly for these Kentucky Power and AEPSC  
 6 employees. Companies must often increase compensation to address labor shortages,  
 7 ensuring they attract and retain necessary employees, which is particularly important  
 8 for utilities that are obligated to serve. Engineering, cybersecurity, and data science are  
 9 other examples of disciplines for which compensation has been increasing at  
 10 significantly higher than average rates.

1   **Q.   HOW DOES TARGET TOTAL COMPENSATION FOR SALARIED**  
2   **NONEXEMPT POSITIONS COMPARE WITH MARKET DATA?**

3   A.   As shown in Figure ARC-6 below, which graphs the market compensation comparisons  
4   provided in Exhibit ARC-3, on average the Company's and AEPSC's target TCC for  
5   50 salaried nonexempt positions with 504 employees is slightly above the  
6   market-competitive range (0.8% above the market median). However, like the  
7   compensation for physical, craft and technical employees and consistent with the  
8   Company's and AEPSC's Total Compensation design, STI is an integral component of  
9   the market-competitive Total Compensation opportunity for these employees. Figure  
10   ARC-6 also shows that, if STI is excluded, then the average target TCC for these  
11   positions would be 5.3% below the market median and 36% of these positions would  
12   be paid less than the market-competitive range, significantly complicating employee  
13   attraction and retention.



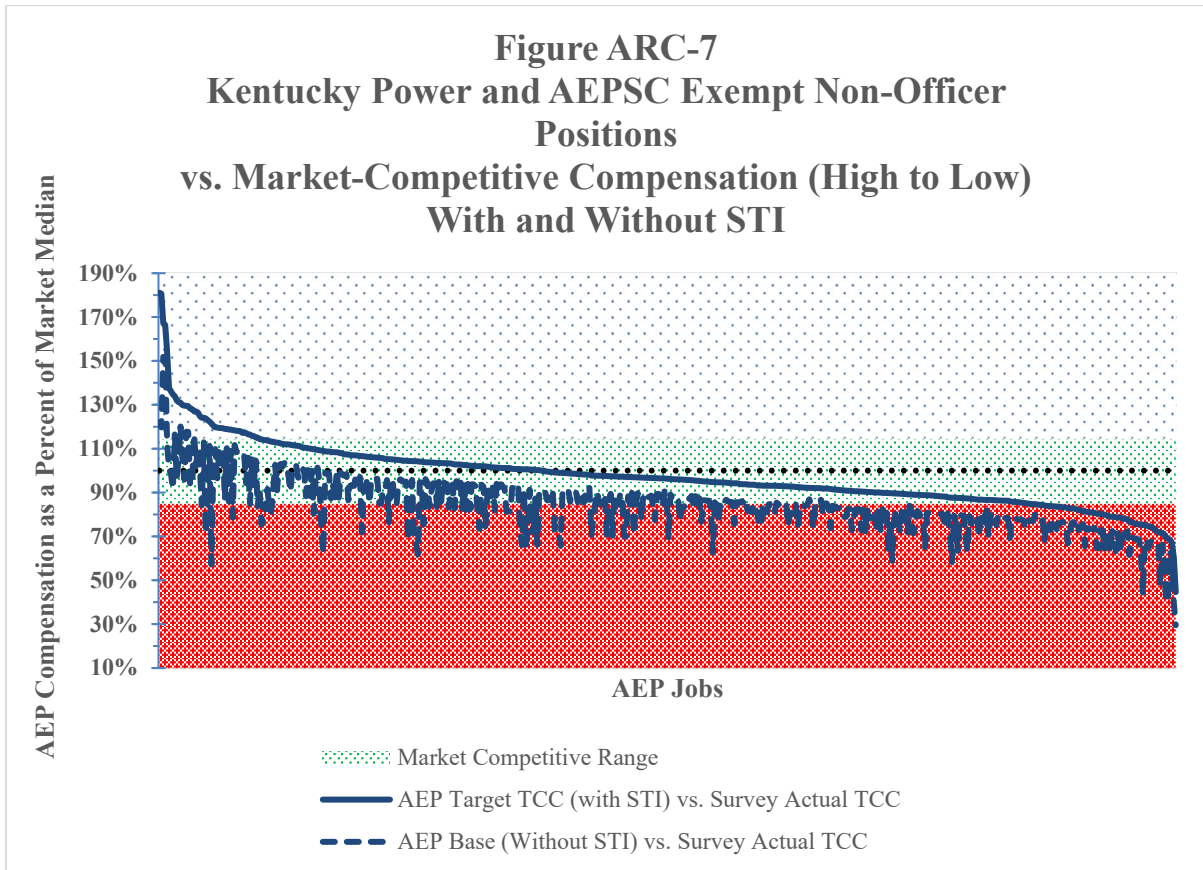


1 **Q. HOW DOES TARGET TOTAL COMPENSATION FOR EXEMPT**  
 2 **NON-OFFICER POSITIONS COMPARE WITH MARKET DATA?**

3 A. As shown in Figure ARC-7 below, which graphs the market compensation comparisons  
 4 provided in Exhibit ARC-4, Kentucky Power and AEPSC's compensation for exempt  
 5 positions, other than the Companies' officers, was 2.4% below the market median.<sup>2</sup>  
 6 However, Figure ARC-7 also shows that, excluding STI, the average target total cash  
 7 compensation for these 528 positions, encompassing 2,754 employees, would fall  
 8 16.0% below the market median and 56% of these positions would be paid below the

<sup>2</sup> 2024 Willis Towers Watson Energy Services and General Industry Middle Management, Professional & Support surveys or, in a few cases, the 2024 Willis Towers Watson Energy Services and General Industry Executive Compensation Surveys, in all cases aged from April 1, 2024 to May 31, 2025 at 3.5% annual rate.

1 market-competitive range making attraction and retention of these positions  
 2 problematic.<sup>3</sup>

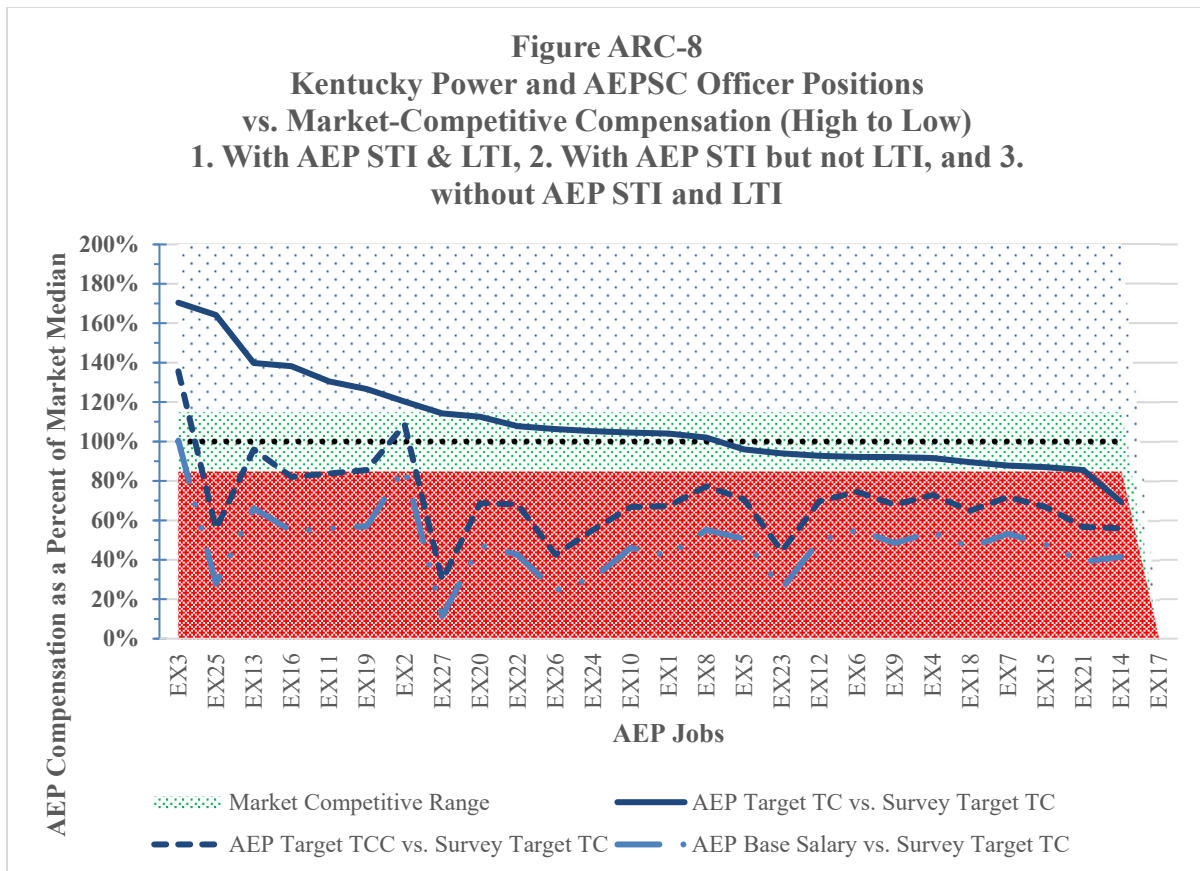


3 **Q. HOW DOES TARGET TOTAL COMPENSATION FOR OFFICER**  
 4 **POSITIONS COMPARE WITH MARKET DATA?**

5 A. The Human Resources Committee of AEP's Board of Directors ("HR Committee")  
 6 annually engages a nationally recognized, independent executive compensation  
 7 consulting firm to conduct a compensation study of senior executive positions. The  
 8 primary peer group for this study includes companies chosen by the HR Committee to

<sup>3</sup> For exempt positions a slightly broader range of +/- 15% of market median is used as the market-competitive range, which is typical for exempt positions.

1 represent the talent markets in which AEP competes to attract and retain senior  
2 management and executive employees. The data for this study and for other officer  
3 positions included in Exhibit ARC-5 was obtained from the 2024 Willis Towers  
4 Watson Energy Services and General Industry Executive Compensation or Middle  
5 Management, Professional & Support surveys, in all cases aged from April 1, 2024 to  
6 May 31, 2025, at 3.5% annual rate. Figure ARC-8 below shows that 2025 officer  
7 compensation was within the market-competitive range overall for 27 officer positions  
8 (28 incumbents), inclusive of Kentucky Power officer positions and AEPSC officer  
9 positions whose compensation is likely billed to Kentucky Power. However, Figure  
10 ARC-8 also shows that Total Compensation would be below the market-competitive  
11 range for a large majority of these positions without the STI component of Total  
12 Compensation. Additionally, without both the STI and LTI component nearly all these  
13 positions would be below the market-competitive range.



**Q. IS THE COMPENSATION OPPORTUNITY THAT THE COMPANIES' INCENTIVE COMPENSATION PROVIDES NECESSARY FOR ATTRACTING AND RETAINING SUITABLE EMPLOYEES?**

**A.** Yes. It is a best practice in compensation design to rely on robust compensation survey data for similar employers, such as the data included in Exhibits ARC-2 through ARC-5 and Figures ARC-5 through ARC-8, to gauge the reasonableness of employee compensation. These exhibits and figures support the reasonableness of AEP's compensation levels as compared to other non-affiliated utility and other comparable employers. They also show that without the target value of Incentive Compensation, the Companies would struggle to offer market-competitive compensation opportunities

1 to employees. For higher-level management and executive positions, the portion of  
2 compensation provided by STI and LTI compensation is necessary, both individually  
3 and in combination, to maintain any semblance of market-competitive total  
4 compensation for these positions. It is highly likely that, without the compensation  
5 opportunity that Incentive Compensation provides, the Companies would experience  
6 increased turnover among all categories of employees and problematic levels of  
7 turnover for the many positions for which the average TCC would then be below the  
8 market-competitive range. High turnover and difficulty attracting suitable new  
9 employees at Kentucky Power and AEPSC would lead to service inefficiencies, longer  
10 outages, and increased costs for customers due to a lack of skilled and experienced  
11 employees. Absent the STI and LTI portions of compensation, Kentucky Power and  
12 AEP would need to shift more pay into Base Pay, which is not a preferred structure for  
13 the reasons explained in more detail in Section VIII of my Direct Testimony. These  
14 analyses show that the portion of compensation provided by STI for all types of  
15 employees is necessary to maintain the competitiveness of the Company's and  
16 AEPSC's Total Compensation. As such, the target expense associated with the  
17 Company incentive compensation for all types of positions, irrespective of the form in  
18 which it is provided, is a necessary, reasonable, and appropriate cost of providing the  
19 electric service to Kentucky Power customers.

1 **Q. DOES ANY PORTION OF THE TARGET LEVEL OF INCENTIVE**  
2 **COMPENSATION EXCEED THE AMOUNT THAT IS REQUIRED TO**  
3 **PROVIDE MARKET-COMPETITIVE COMPENSATION TO EMPLOYEES?**

4 A. No. As Figures ARC-5 through ARC-8 show, the target STI and LTI components of  
5 Total Compensation are not a “bonus” that provides compensation in excess of market  
6 competitive Total Compensation. Rather, such Incentive Compensation is a critical  
7 element of a reasonable, necessary, and prudent market competitive Total  
8 Compensation package.

9 **Q. ARE BOTH BASE PAY AND INCENTIVE COMPENSATION PART OF AN**  
10 **OVERALL REASONABLE LEVEL OF TOTAL COMPENSATION?**

11 A. Yes. As shown for each group of employees in the preceding questions, the Total  
12 Compensation for all types of positions is within the market competitive range, which  
13 is a reasonable level of compensation.

#### **VIII. THE BENEFITS OF INCENTIVE COMPENSATION**

14 **Q. WHAT ARE THE BENEFITS TO KENTUCKY POWER CUSTOMERS OF**  
15 **THE COMPANY’S INCENTIVE COMPENSATION?**

16 A. First and foremost, the Company’s STI and LTI compensation benefits customers as  
17 part and parcel of a Total Compensation package that enables the Company to attract  
18 and retain the suitably skilled and experienced employees needed to provide service to  
19 customers efficiently, effectively, and safely. The ability to attract and retain such a  
20 workforce is, quite simply, essential to meeting customers’ needs at a reasonable cost.  
21 Without the compensation opportunity that the Company’s Incentive Compensation  
22 provides, the Total Compensation for many positions would be below the

1 market-competitive range, as shown in Figures ARC-5 through ARC-8 and Exhibits  
2 ARC-2 through ARC-5. This would impair the Company's ability to attract and retain  
3 such employees, increase employee turnover, and reduce employee engagement. This,  
4 in turn, would increase hiring and training costs, reduce productivity, increase position  
5 vacancy, decrease response time and service levels, and increase the cost-of-service for  
6 customers.

7 The Company's Incentive Compensation is part of a competitive Total  
8 Compensation package, costing no more than providing market-competitive  
9 compensation with Base Pay alone. Incentive Compensation also helps maintain higher  
10 levels of employee and Company performance than would be achieved using Base Pay  
11 alone. It does this by linking a portion of employees' total compensation opportunity  
12 to performance without increasing the Company's compensation expense.

13 **Q. HOW DOES INCENTIVE COMPENSATION IMPROVE EMPLOYEE AND**  
14 **COMPANY PERFORMANCE?**

15 A. It does so by more effectively communicating goals and objectives, better aligning  
16 employee efforts with these goals and objectives, more effectively engaging  
17 employees, and motivating employees to achieve higher levels of performance.

18 Specifically, Incentive Compensation helps create a high-performance culture by:

- 19 • Giving all employees a personal stake in achieving common goals and objectives,  
20 which creates a sense of shared purpose and improves employee engagement,  
21 which is linked to improved employee and Company performance.
- 22 • Communicating goals and objectives to all managers and employees more  
23 effectively than is otherwise possible, which helps align and focus work  
24 assignments and employee efforts with these objectives.
- 25 • Encouraging and motivating employees to expend discretionary effort to achieve  
26 these goals and objectives.

- Varying compensation based on individual employee performance, which recognizes and appropriately adjusts compensation, which contributes to a high-performance culture by improving employee engagement, encouraging performance improvement, improving retention of high performers, and reducing retention of poor performers.
- Rewarding employees for achievement of the Company's goals and objectives, which reinforces the importance of these goals and objectives, recognizes and rewards high performance, identifies and reduces rewards for low performance and improves employee engagement.
- Encouraging high levels of productivity.

Incentive Compensation helps lower service costs for Kentucky Power's customers compared to what they would be without these benefits.

**Q. DO THE GAINS PRODUCED BY INCENTIVE COMPENSATION RESULT IN AN ACCUMULATION OF BENEFITS AND COST SAVINGS THAT ACCRUE TO KENTUCKY POWER CUSTOMERS EACH YEAR?**

A. Yes. The Company's STI and LTI compensation programs have been in place for more than two decades, and these programs have produced benefits that inured to customers in base rate cases over these many years. These benefits are generally the result of the high-performance culture that the Company's Incentive Compensation encourages. The accumulated value that has been produced over the more than two decades that these programs have been in place was reflected in the Company's cost-of-service for the current and prior base rate cases. It has, therefore, inured to customers through lower rates in prior rate proceedings and any additional value it has created since the last base rate case will again inure to customers when the rates set in this case are effective. These benefits gradually accumulated over time and would likely diminish over time if Incentive Compensation were eliminated. Such "back-sliding" would be detrimental to Kentucky Power customers.



**Short-Term Incentive (STI) Compensation**

1   **Q.   PLEASE DESCRIBE THE STI COMPENSATION EXPENSE THAT**  
2   **KENTUCKY POWER IS REQUESTING IN ITS COST-OF-SERVICE.**

3   A.   Kentucky Power is requesting the inclusion of the target level of direct incentive  
4       compensation during the test year in its revenue requirement in this case, rather than  
5       the lower per books expense. The adjustment to increase the cost of annual and  
6       long-term incentive compensation to the target level (W30) is supported by Company  
7       Witness Ciborek. The Company is also requesting inclusion of the test-year amounts  
8       of indirect STI of AEPSC and other affiliates that were charged to Kentucky Power,  
9       which were lower than target in the test year. Consistent with its historical practice, the  
10      Company is not requesting an adjustment for indirect AEPSC and other affiliate STI to  
11      the target level, which would also increase the cost-of-service even though these costs  
12      have averaged 117% and 136% of target over the last five and 10 years, respectively.

13           The Company is requesting the higher test-year target amount be included in its  
14      revenue requirement for four reasons: (1) the target level of Incentive Compensation is  
15      the amount the Company needs to provide on average to maintain market competitive  
16      Total Compensation, (2) requesting the target level of Incentive Compensation is  
17      consistent with the Company's historical practice, (3) the Company expects to pay at  
18      least this much, on average going forward, and (4) the Company has historically paid  
19      substantially above the target level over the last five and 10 years.

20   **Q.   HOW COMMON IS STI COMPENSATION IN THE UTILITY INDUSTRY?**

21   A.   STI compensation is nearly universally prevalent for energy services industry  
22      positions, which clearly shows that, at a minimum, employers in this industry believe

1 that using STI compensation is superior to its only alternative, which is providing  
2 market-competitive compensation through Base Pay alone. STI compensation is  
3 provided by the majority of employers to nearly all Kentucky Power and AEPSC  
4 positions and is almost universally provided to higher-level positions both in the energy  
5 services industry and in U.S. industry in general. The compensation analyses contained  
6 in Exhibits ARC-2 through ARC-5 show that market median Total Compensation  
7 includes Incentive Compensation for 97.7% of the 657 positions with 3,544 incumbents  
8 included in these market compensation analyses. In addition, median target STI  
9 compensation was at least 5% of base salary in market survey information for positions  
10 at all base salary levels in the energy services industry, including positions with base  
11 salaries of \$30,000-\$40,000.<sup>4</sup> This survey analysis is very robust, including 160 energy  
12 services industry employers and 336,490 incumbent employees.

13 **Q. PLEASE DESCRIBE THE STI PLANS FOR KENTUCKY POWER AND**  
14 **AEPSC EMPLOYEES.**

15 A. All regulated employees, from hourly positions through executive management, except  
16 co-op students and interns, participate in the STI program. The 2025 STI target  
17 percentage for most physical, craft, and technical positions was 3% of eligible earnings,  
18 which includes base wages, overtime, and shift premiums. The STI targets for salaried  
19 positions vary by salary grade level. STI targets are designed to ensure Total

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<sup>4</sup> Willis Towers Watson; 2024 Energy Services Middle Management, Professional and Support Survey Report  
— United States; Compensation Report; Base/Bonus/Target Bonus Summary Tables by Salary Range  
(Incumbent-Weighted) - Total Sample.

1 Compensation aligns with market standards, aiming to match the market median for  
2 each salary grade. This approach is typical for U.S. industrial companies.

3 The AEPSC compensation team uses a standard plan design and template for  
4 all STI plans with separate performance measures and communications for employees  
5 in each operating company, business unit, and most major centralized functions. The  
6 overall performance score for each scorecard determines the award payout for that  
7 group from the available funding. The funding is determined by the AEP Scorecard  
8 (Exhibit ARC-7). Overall performance scores and award payouts can range from 0%  
9 to 200% of the target. AEPSC employees in AEP legal, business transformation, and  
10 AEP's President and CEO do not have separate scorecards but instead participate in  
11 STI compensation based on the AEP (funding) scorecard.

12 Performance targets are established for STI measures at challenging yet  
13 achievable levels to ensure that employees have a reasonable expectation that STI will  
14 pay out at or above the target level on average over multiple years. This expectation is  
15 foundational because, without it, many employees would not perceive their Total  
16 Compensation opportunity to be market-competitive and employee attrition would  
17 increase to problematic levels. However, most participants understand that STI  
18 compensation is variable and may vary both above and below target from year-to-year  
19 but that it can reasonably be expected to meet or exceed the target level on average  
20 over longer periods. AEP's STI payouts have averaged 117% and 136% of target over  
21 the last five and 10 years, respectively.

1 **Q. PLEASE DESCRIBE THE KEY PERFORMANCE INDICATORS BY WHICH**  
 2 **KENTUCKY POWER IS MEASURED AND THEIR ASSOCIATED**  
 3 **BENEFITS.**

4 A. As shown in Exhibit ARC-6, Kentucky Power's 2025 STI compensation is based on a  
 5 balanced scorecard of key performance indicators ("KPIs") that serve as incentive goals  
 6 and is designed to drive the achievement of AEP's six core principles, which are:

- 7 • Customer Service
  - 8 ○ Industry-best customer experience
- 9 • Employee Commitment
  - 10 ○ Safe and secure workplace
  - 11 ○ Engaged, trained and developed employees
- 12 • Regulatory and Legislative Integrity
  - 13 ○ Balance regulatory outcomes
  - 14 ○ Trusted industry leadership
- 15 • Environmental Respect
  - 16 ○ Creative sustainable solutions
- 17 • Operational Excellence
  - 18 ○ World class asset performance
- 19 • Financial Strength
  - 20 ○ Strong financial discipline

21 Equal weights are assigned to each of the core principles and, if a core principle has  
 22 multiple KPIs, then those KPIs are also equally weighted within the Core Principle.

23 The KPIs in the Kentucky Power Scorecard provide the following numerous  
 24 specific benefits to customers:

- 25 • Customer Service: The "Industry Best Customer Experience" is comprised of two  
 26 KPIs – improved customer satisfaction and improved power quality. The customer  
 27 satisfaction KPI is based on improvement in Kentucky Power's J.D. Power overall  
 28 satisfaction rank compared to all 151 other participating utilities. The power quality  
 29 KPI measures the reduction in the number of customers who experience 13 or more

1 interruptions, including momentary interruptions, during the year. Both of these  
2 KPIs directly benefit customers resulting in tangible customer service and  
3 reliability improvements.

- 4 • Employee Commitment: The “Safe and Secure Workplace” is comprised of physical  
5 and cyber components. The 2025 physical safety KPIs are measured by Total  
6 Recordable Incident Rate (“TRIR”) and Days Away, Restricted Duty and Transfer  
7 (“DART”) Rate. The physical safety KPIs benefit customers by reducing the  
8 number and severity of safety incidents and thereby, also their human and economic  
9 cost, the latter of which impacts the cost-of-service for Kentucky Power customers.  
10 The cybersecurity KPI is measured by Phishing Failure Rate. This benefits  
11 customers by emphasizing the need to reduce phishing failures, encouraging  
12 teamwork, establishing potentially serious consequences for repeat offenders,  
13 directly reducing cyber security risk and thereby mitigating cyber security-related  
14 risks and costs. The “Engage, Train, and Develop” KPI improves the organization’s  
15 workforce and improves the ability of Kentucky Power and AEPSC to attract and  
16 retain suitable talent, which benefits Kentucky Power customers by lowering the  
17 costs of attracting and keeping employees compared to what it would otherwise be.
- 18 • Regulatory and Legislative Integrity: The “Achieve Plan Return on Equity  
19 (‘ROE’)” is measured by ROE results. This KPI benefits customers by better  
20 ensuring the Company earns a sufficient return to ensure equity capital is available  
21 at a reasonable cost to maintain and expand the Kentucky Power electric system to  
22 meet the needs of customers for stable and affordable electricity. This goal also  
23 encourages all employees to maintain financial discipline, which benefits

1 customers by reducing the cost-of-service compared to what it would be otherwise.  
2 The Reduce Notices of Violation (“NOV”) KPI reduces the number of enforcement  
3 actions Kentucky Power incurs, which is any documented correspondence from an  
4 agency of an alleged deviation or non-compliance with a regulatory requirement.  
5 This benefits customers by reducing the expense incurred due to these events, the  
6 impact of the Company’s operations on the environment, and the risk of future  
7 NOV events.

- 8 • Environmental Respect: The Environmental Respect KPI is measured by a  
9 reduction in the number of environmental events, such as a spill or lack of  
10 conformance with an environmental permit or regulatory requirement. This also  
11 benefits customers by reducing the expense incurred due to these events, the impact  
12 of the Company’s operations on the environment, and the risk of future  
13 environmental events.
- 14 • Operational Excellence: The “Worldclass Asset Performance” KPI is measured by  
15 achieving certain targets: the System Average Incident Duration Index (“SAIDI”)  
16 and Effective Forced Outage Rate when a generating unit is in demand (“EFORD”).  
17 This directly benefits customers by reducing the duration of service interruptions,  
18 improving the reliability of their electric service, and thereby reducing the costs  
19 customers incur because of service interruptions. The EFORD goal is a measure of  
20 generation forced outages when plants are in demand, which benefits customers by  
21 reducing forced outages that would require purchasing replacement power from the  
22 market at a higher price to meet the needs of customers and, thereby, reducing  
23 generation costs to customers.

- Financial Strength: The Operating Earnings, Operations & Maintenance Budget and Funds from Operations (“FFO”)/Debt KPIs all drive “strong financial discipline.” This benefits customers by better ensuring the Company earns sufficient returns to ensure equity and debt capital is available at reasonable costs to maintain and expand the Kentucky Power electric system to meet the needs of customers for stable and affordable electricity. These KPIs also encourage all employees to maintain financial discipline, which benefits customers by reducing the cost-of-service below what such costs would be otherwise.

**Q. PLEASE DESCRIBE HOW STI COMPENSATION FUNDS ARE ALLOCATED.**

A. The available funding is allocated to each incentive group, such as Kentucky Power, based on their scorecard result relative to the scorecard results of all other incentive groups. This produces performance differentiated scores for each incentive group that precisely utilize the funding available, which eliminates the risk that scores will produce awards that are more or less than the available funding. This allocation methodology uses the Average Performance Score (“APS”) as a statistical normalizing function. APS is calculated as the average of all Incentive Group scorecard results, weighted by the sum of the target awards for all Participants in each incentive group as reflected in Figure ARC-9 below.

Figure ARC-9					
Scorecard	2025 Result	Sum of Target Awards for All Participants	% of Total ICP Target	Weighted Result	
Incentive Group 1	0.925	\$2,000,000	×	20.0%	= 0.185
Incentive Group 2	0.786	\$5,000,000	×	50.0%	= 0.393
Incentive Group 3	0.585	\$3,000,000	×	30.0%	= 0.176
		\$10,000,000			<b>0.754 = APS</b>

1           The overall score for each Incentive Compensation Plan (“ICP”) Scorecard is  
2           calculated by multiplying the Incentive Group’s ICP scorecard result by the AEP  
3           Scorecard Result, which is assumed to be 1.049 in this example, and then dividing by  
4           APS as shown in Figure ARC-10 below.

Figure ARC-10					
Scorecard	2025 Result	AEP Scorecard Result	APS	Overall Score	
Incentive Group 1	0.925	×	1.049	÷	0.754 = 128.8%
Incentive Group 2	0.786	×	1.049	÷	0.754 = 109.4%
Incentive Group 3	0.585	×	1.049	÷	0.754 = 81.4%

5           The score for all employees in groups that do not have a separate scorecard is the AEP  
6           scorecard result.

7   **Q.   WHAT ARE THE KEY DRIVERS OF STI COMPENSATION FOR**  
8   **KENTUCKY POWER EMPLOYEES?**

9   A.   The balanced KPIs in the Kentucky Power scorecard are the key drivers of STI  
10       compensation for Kentucky Power employees because these are the only KPIs  
11       Kentucky Power employees can generally control (*see* Exhibit ARC-6). If Kentucky  
12       Power employees do not achieve the KPIs on the Kentucky Power scorecard, they



1 would not be paid a significant STI award, irrespective of AEP's or Kentucky Power's  
2 financial performance.

3 **Q. ARE THE AEP (FUNDING) SCORECARD KPIS THE SAME AS THE**  
4 **KENTUCKY POWER KPIS?**

5 A. The AEP (funding) Scorecard KPIs are the same as the Kentucky Power's KPIs, with  
6 the following changes:

- 7 1) Phishing Failure Rate is replaced by Safety Improvement Plan & Training in  
8 the Employee Commitment Core Principle, which helps improve the safety of  
9 the workforce. This benefits customers by reducing the cost of safety incidents  
10 and their impact on family, friends, colleagues and the communities we serve;
- 11 2) There is not an NOV goal for the Regulatory and Legislative Integrity core  
12 principle, which increases the weight on the remaining Achieve Plan ROE KPI  
13 for this Core Principle to 16.67%;
- 14 3) The EFORD measure is replaced by a Transmission Reliability Index goal in  
15 the Operational Excellence core principle, which better ensures that customers  
16 are receiving the maximum benefit of Transmission assets;
- 17 4) The O&M Budget and FFO/Debt goals are eliminated, which increases the  
18 weight on operating earnings (measured on a per share basis) to 16.67%; and  
19 5) All the metrics are set and measured at the AEP level.

20 **Q. WHAT IS THE PURPOSE OF THE AEP SCORECARD AND FUNDING**  
21 **MECHANISM FOR STI COMPENSATION?**

22 A. The AEP Scorecard (Exhibit ARC-7) is used to fund all Incentive Compensation for  
23 AEP's regulated employees. The funding mechanism allows AEP to provide employee

1 Incentive Compensation without compromising its obligations to other stakeholders,  
2 which includes Kentucky Power customers. It also ensures that STI compensation does  
3 not impair Kentucky Power or AEPSC financially, which helps avoid the increased  
4 costs that would create, such as increased borrowing costs that Kentucky Power  
5 customers would likely at least partially absorb if AEP were financially impaired even  
6 to a small extent. The importance of such a mechanism becomes apparent when utilities  
7 are in financial distress. For example, PG&E needed to take extraordinary measures to  
8 eliminate incentive compensation while they were in financial distress, a decision the  
9 California Consumer Counsel agreed with, because their STI did not have a funding  
10 mechanism that adjusted incentive payouts commensurate with the Company's  
11 financial performance. Managing expenses within a budget is crucial to maintaining  
12 financial stability and avoiding financial difficulties.

13 The funding mechanism also facilitates goal setting by shifting the focus to  
14 ensuring a consistent degree of difficulty among AEP's business units and operating  
15 companies. The AEP Operating EPS component of the Funding Measures emphasizes  
16 the importance of financial discipline among employees. This drives a continuous  
17 pursuit of efficiency and cost reduction that enables the Company to complete work at  
18 a lower cost than would otherwise be the case, which benefits customers.

19 **Q. DO THE SCORECARD KPIS DIFFER FROM PREVIOUS YEARS?**

20 A. Yes. While the structure of how compensation is awarded remains the same, in 2025  
21 the Company revamped its KPIs to track its new core principles. This not only resulted  
22 in new KPIs but dramatically different weighting. For instance, there is a reduction in  
23 the weight of financial measures in the AEP (funding) Scorecard from 60% in past

1 years to 25%, inclusive of both the Operating Earnings Per Share (“EPS”) KPI for the  
2 Financial Strength Core principle and Achieve Plan ROE measure for the Regulatory  
3 and Legislative Integrity Core Principle.

4 **Q. WHAT SPECIFIC BENEFITS DO THE FINANCIAL MEASURES IN THE STI**  
5 **COMPENSATION PROGRAM PROVIDE TO CUSTOMERS?**

6 A. The financial measures in the Kentucky Power and AEP Scorecards focus employees  
7 on cost control, adherence to budget, and promoting the efficient use of financial  
8 resources, which is essential for providing reliable service at a reasonable cost to  
9 customers. Financial measures continuously emphasize the importance of maintaining  
10 financial discipline and directly encourage employees to spend conservatively, operate  
11 efficiently, and maximize resources. This has and will continue to directly benefit  
12 customers by reducing the Company’s cost-of-service through cost savings that are  
13 passed on to customers in rates.

14 Financially based Incentive Compensation also reduces earnings volatility and  
15 bolsters the Company’s financial stability. This reduces the Company’s cost of capital  
16 and better ensures access to capital at reasonable rates, particularly during recessionary  
17 and other periods of weaker earnings, such as those caused by major storms, weak  
18 economic activity, and catastrophic events when capital may otherwise be overly  
19 expensive or inaccessible. Furthermore, ensuring that Incentive Compensation  
20 payments do not impair the Company financially reduces the risk of additional expense  
21 caused by such difficulties, which would be borne by Kentucky Power customers.  
22 Furthermore, maintaining financially based STI measures prevents backsliding on  
23 previously achieved cost-control and efficiency savings. These effects all reduce actual

1 and potential costs for Kentucky Power customers relative to what they would be  
2 without such STI compensation.

3 **Q. WHAT OTHER SPECIFIC BENEFITS DOES STI PROVIDE?**

4 A. In addition to enabling the Company to attract and retain the suitably skilled and  
5 qualified employees needed to provide service to customers efficiently, effectively, and  
6 safely, the benefits of STI compensation include:

- 7 • Enhancing employee interest and engagement in goals and performance toward  
8 them, which motivates employees to achieve them, following the principle “what  
9 gets measured gets done”;
- 10 • Aligning goals and employee efforts throughout the organization, which better  
11 ensures that adequate time, attention, and resources are provided for their  
12 achievement and better ensures that all employees are pulling in the same direction.
- 13 • Rewarding employees for achievement of goals and objectives, which reinforces  
14 their positive behavior when they succeed;
- 15 • Enhancing the organization’s culture and performance by giving all employees a  
16 personal stake in achieving these goals and objectives and thereby creating a shared  
17 purpose;
- 18 • Creating a culture of high performance and cost consciousness; and
- 19 • Reducing costs through increased productivity and a relentless pursuit of cost  
20 savings.

21 **Q. DOES STI COMPENSATION BENEFIT CUSTOMERS?**

22 A. Yes. I have shown that the Company’s STI benefits customers and serves their interests,  
23 particularly the financial portion of it, which drives cost savings that directly benefits

1 customers. The entire target level of STI compensation is a necessary cost of providing  
2 service to customers because it is a component of a market-competitive Total  
3 Compensation package that is needed to attract and retain employees with the skills  
4 and experience necessary to provide service to customers efficiently, effectively, and  
5 safely. This compensation expense would still be necessary if the Company only used  
6 Base Pay compensation to compensate employees.

7 The accumulated cost savings that the Company's STI compensation has  
8 produced over the decades that it has been in place are reflected in Kentucky Power's  
9 test-year cost-of-service. These savings will again be embedded in rates as they have  
10 been in prior base rate case proceedings and will pass through to customers. There is  
11 no mechanism for these benefits to flow to AEP shareholders. Excluding any part of  
12 the target STI compensation from Kentucky Power's revenue is unjustified because, as  
13 the evidence shows, it primarily benefits customers and the loss of this revenue would  
14 impede the Company's ability to earn the rate of return set by the Commission in this  
15 proceeding.

#### **LTI Compensation**

16 **Q. PLEASE DESCRIBE THE LTI COMPENSATION EXPENSE THAT**  
17 **KENTUCKY POWER IS REQUESTING IN ITS COST-OF-SERVICE IN THIS**  
18 **CASE.**

19 A. The Company is requesting that the test-year target level of \$207,954 of LTI expense  
20 be included in its cost-of-service. This is the target level of direct Kentucky Power  
21 Company LTI compensation and indirect Wheeling Power Company LTI  
22 compensation for the Kentucky Power Company's share of the Mitchell generating

1 plant. The Company is also requesting inclusion of the test-year amounts of indirect  
 2 LTI costs of AEPSC and other affiliates that were charged to Kentucky Power, which  
 3 were lower than target. Consistent with its historical practice, Kentucky Power is not  
 4 requesting an adjustment to increase LTI expense in cost-of-service for indirect AEPSC  
 5 and other affiliate expense, even though these expenses have averaged significantly  
 6 above the target level over the last five and ten years. The requested LTI compensation  
 7 includes both performance shares and restricted stock units (“RSUs”), which are the  
 8 two types of LTI compensation that the Company and other AEP affiliates utilize.

9 LTI compensation provides the same benefits to customers as STI  
 10 compensation in many respects, except that it is tied to performance and employee  
 11 retention over a longer time-period. LTI compensation, or some other form of  
 12 compensation with a similar value to participants, is necessary to attract and retain  
 13 suitable employees for LTI eligible positions, rather than the actual per books expense.  
 14 This is also the minimum level that the Company expects to incur in an average year  
 15 going forward. Historically the Company has paid well above target LTI compensation  
 16 (see Figure ARC-11 below).

Figure ARC-11	
	Performance Award Score
5-Year Average	114.5%
10-Year Average	122.2%

17 **Q. PLEASE BRIEFLY DESCRIBE THE LTI PROGRAM FOR KENTUCKY**  
 18 **POWER AND AEPSC EMPLOYEES.**

19 A. LTI compensation is managed by the AEPSC compensation team as part of an AEP  
 20 systemwide LTI program for all AEP affiliates. Like STI compensation, it is an integral

1 component of reasonable and market-competitive Total Compensation for eligible  
2 employees. As previously stated, market-competitive Total Compensation is necessary  
3 to attract and retain suitably skilled, experienced, and knowledgeable employees  
4 efficiently and effectively. As such, LTI compensation has no incremental cost above  
5 the cost of providing market-competitive Total Compensation through Base Pay alone,  
6 which would be the alternative to providing Incentive Compensation such as LTI. But  
7 LTI compensation is preferential to an equivalent Total Compensation exclusively  
8 through Base Pay as it encourages long-term perspective in decision making and  
9 supports operational continuity by enhancing participant retention over time.

10 Approximately 1,348 employees (about 8% of all AEP employees) received an  
11 annual LTI award in 2025. Participation is generally provided to employees in positions  
12 that have responsibility for decisions that have a longer-term impact on operations and  
13 customers. Such employees often have historical and experiential knowledge of our  
14 practices and often assist in creating and implementing the vision of how we can best  
15 serve customers. LTI participants are often responsible for maintaining employee focus  
16 on customers, making often-difficult resource allocation decisions, and driving  
17 customer experience improvements. Because of the value these employees provide,  
18 retaining them is particularly important to providing high quality service to customers  
19 at a reasonable cost. The LTI compensation program is designed to foster the retention  
20 of such participants.

21 The annual LTI awards granted during the test year were composed of 75%  
22 performance shares and 25% restricted stock units (“RSUs”).

1   **Q.     PLEASE DESCRIBE PERFORMANCE SHARES.**

2   A.     Performance shares are generally similar in value to shares of AEP common stock, but  
3           participants must continue their AEP employment over a three-year period to earn a  
4           payout unless the participant retires, is severed, or dies. Otherwise, performance shares  
5           are forfeited upon termination of employment. The number of performance shares that  
6           participants ultimately earn is tied to AEP's longer-term performance relative to  
7           pre-established performance measures. Performance shares granted during the test year  
8           have two performance measures:

- 9           • Three-year cumulative AEP operating earnings per share ("Operating EPS")  
10           measured relative to a Board-approved target (50% weight), and
- 11          • Three-year AEP total shareholder return ("TSR") measured relative to a peer group  
12           of similar utility companies (50% weight).

13                 As with the Company's STI, the maximum score for all LTI performance  
14           measures is 200% of target. These LTI measures help ensure that management drives  
15           the changes needed to keep pace with the rapidly changing business landscape and  
16           amplified societal expectations, while better positioning Kentucky Power and other  
17           AEP system companies for success in the future. Taken together, the STI and LTI  
18           performance measures balance the short-term and long-term interests of customers,  
19           employees, shareholders, and other stakeholders.

20   **Q.     PLEASE DESCRIBE THE COMPANY'S RSUS GRANTED TO KENTUCKY**  
21   **POWER AND AEPSC EMPLOYEES.**

22   A.     RSUs provide the remaining 25% of the LTI value and are also generally similar in  
23           value to shares of AEP common stock. RSUs generally vest, subject to the participants'  
24           continued AEP employment, on three vesting dates over approximately a three-year



1 period. RSUs are not tied to any performance measures (financial or otherwise) but are  
2 instead provided to foster employee retention over a longer period. Participants who  
3 remain continuously employed with AEP through an RSU vesting date receive an equal  
4 number of shares of AEP common stock as the number of RSUs that vest on such date.  
5 Otherwise, with certain exceptions such as severance due to position eliminations,  
6 retirement (2025 and later awards only), or a participant's death, RSUs are forfeited  
7 upon employment termination.

8 **Q. IS LTI COMPENSATION A PREVALENT FORM OF COMPENSATION FOR**  
9 **THE UTILITY INDUSTRY?**

10 A. Yes, it is highly prevalent. Nearly all publicly owned U.S. utility companies have  
11 similar LTI programs, as do nearly all public U.S. general industry companies. LTI  
12 compensation is a significant component of energy services industry total  
13 compensation for higher paid positions, providing compensation equivalent to 58% of  
14 base salary at the median for all 137 organizations with 4,293 incumbents for which a  
15 sufficient sample was available for these positions.<sup>5</sup> Exhibit ARC-5 also shows that  
16 LTI compensation is a substantial component of market-competitive compensation for  
17 all the positions included in this analysis.

18 **Q. WHAT ARE THE BENEFITS TO CUSTOMERS FROM THE COMPANY'S**  
19 **LTI COMPENSATION PROGRAM?**

20 A. First and foremost, as with STI compensation, LTI compensation is an integral  
21 component of the market-competitive total compensation package used to attract and

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<sup>5</sup> Willis Towers Watson, 2024 Energy Services Executive Survey Report — United States, Compensation Report, Long-Term Incentive Annualized Value Table (Incumbent-Weighted).

1 retain the suitable employees necessary to provide service to customers efficiently and  
2 effectively. LTI compensation also provides a retention incentive to participants, which  
3 benefits customers by improving the retention of employees with more important  
4 knowledge, skills, and experience, as well as greater Company experience, in roles that  
5 have long-term decision-making responsibility, which improves the continuity of the  
6 Company's operations and management.

7 Tying a portion of management compensation to long-term measures of  
8 financial performance, specifically the EPS and TSR measures used in the performance  
9 share awards, encourages better long-term decision making and financial discipline,  
10 which benefits customers by encouraging cost control. Customers benefit from more  
11 efficient, effective, and consistent operations; more skilled, experienced,  
12 knowledgeable, and stable employees in management and other leadership positions;  
13 better long-term decision-making; and stronger financial discipline. All these factors  
14 contribute to lower costs for customers.

15 Maintaining long-term financial discipline is imperative, particularly given the  
16 long-term nature of the assets that comprise the Company's electric system. The EPS  
17 and TSR performance share measures communicate this imperative and strongly  
18 encourage its pursuit, which promotes expense control, efficient operations, and  
19 conservation of resources. This directly benefits customers by reducing the Company's  
20 cost-of-service and rates compared to what they would be otherwise.

21 As with STI compensation, customers benefit from skilled employees attracted  
22 and retained by LTI payouts and the value of achievements incentivized by the LTI  
23 program over the decades that LTI compensation has been in place.

1   **Q.     DO THE TOTAL BENEFITS OF THE LTI COMPENSATION EXCEED ITS**  
2   **COST TO KENTUCKY POWER CUSTOMERS?**

3   A.    Yes. As with STI compensation, LTI compensation is an integral component of a  
4   market-competitive Total Compensation package that would otherwise need to be  
5   borne in Base Pay in order to effectively maintain the Companies' ability to attract and  
6   retain the necessary talent to continue to provide safe and reliable electric services.  
7   Therefore, the target level of LTI compensation does not have any incremental cost to  
8   customers beyond the cost of providing market-competitive Total Compensation  
9   through other types of compensation such as increased Base Pay. By encouraging  
10   participant retention, which improves operational continuity and performance, it  
11   reduces the cost-of-service for customers. It also reduces the cost customers bear by  
12   encouraging long-term financial discipline, among the other benefits previously  
13   mentioned. With significant accumulated benefits, potential new incremental benefits,  
14   and no incremental cost, the benefits of the LTI program to customers clearly exceed  
15   its cost to customers.

16   **Q.     IS IT REASONABLE AND NECESSARY TO INCLUDE LTI**  
17   **COMPENSATION IN THE COMPANY'S COST-OF-SERVICE FOR RATE**  
18   **MAKING PURPOSES?**

19   A.    Yes. LTI compensation has been clearly shown to be a reasonable, customary, and  
20   prudent cost of doing business that provides substantial overall net benefits to  
21   customers because, among other reasons, it:

22           (a) Does not have any incremental cost above the cost of providing  
23           market-competitive compensation through other forms of pay;

- (b) Improves participant retention and, consequently, management and operational continuity;
- (c) Encourages appropriate consideration of longer-term factors in decision making; and
- (d) Improves operating effectiveness and cost control.

As with STI compensation, it is also unreasonable and unsustainable for shareholders to pay the cost of performance improvements derived from LTI compensation when those benefits, both current and accumulated, will and have inured to customers through this and previous base rate case proceedings. Such self-funding is unnecessary when LTI compensation is a component of a market-competitive Total Compensation package that is necessary for the attraction and retention of suitable employees. Also like STI, there is not any mechanism for the accumulated benefits of LTI compensation to flow to shareholder. Furthermore, maintaining LTI compensation prevents backsliding on previously achieved cost-control and efficiency savings. Therefore, it would be just and reasonable to include the full target cost of LTI compensation in Kentucky Power's cost-of-service for ratemaking purposes.

## **IX. EMPLOYEE BENEFITS**

**Q. DESCRIBE THE POLICIES AND OBJECTIVES THAT AEP SEEKS TO ACHIEVE IN THE DESIGN OF THE BENEFIT PLANS OFFERED TO KENTUCKY POWER AND AEPSC EMPLOYEES.**

A. The benefit plans provided to all AEP employees are designed to be an important component of the employees' Total Compensation and benefits package. Specifically, AEP's objectives are to provide benefits offerings that:

- Support the recruitment, motivation and retention of employees with skills needed to achieve the AEP operating companies' and other AEP affiliate business objectives;

- 1 • Protect employees from severe financial hardship due to catastrophic life  
2 events;
- 3 • Provide a variety of benefit offerings that meet the diverse needs of the  
4 workforce;
- 5 • Influence desired behaviors by, for example, providing incentives to encourage  
6 employees to obtain preventive care services under the medical plan and  
7 minimizing inefficient consumption of medical services;
- 8 • Ensure the total cost of benefit programs remains affordable and sustainable for  
9 AEP, employees and customers; and
- 10 • Maintain compliance with applicable federal and state laws.

11 **Q. PLEASE DESCRIBE AEP'S EMPLOYEE BENEFIT PROGRAMS.**

12 A. AEP operates an overall benefits program in which nearly all full-time employees and,  
13 at an increased cost, part-time employees are eligible to participate. The benefits  
14 program includes medical, wellness, dental, sick pay, long-term disability ("LTD"),  
15 life insurance, accidental death and dismemberment, retirement pension, retirement  
16 savings (401k), vacation and holiday benefits. Participation may extend to employee's  
17 families and retirees in some instances. These programs are financed through a  
18 combination of employer and employee contributions. Many of AEP's benefit  
19 programs, including the medical, dental, and LTD programs, are self-funded using a  
20 Voluntary Employee Beneficiary Association Trust, as opposed to utilizing a fully  
21 insured arrangement in which premiums are paid to an insurance company for  
22 coverage. Employee contributions, as well as monthly employer contributions from the  
23 AEP system company for each employee, are deposited to the trust and used to fund  
24 the actual claims and vendor administration expenses as allowed under law. A brief  
25 summary of each health and welfare benefit plan is outlined in Exhibit ARC-8 - Health

1 and Welfare Benefits Summary Chart. Employee benefits are a critical component of  
2 the Companies' ability to attract and retain suitable employees.

3 **Q. WHAT ACTIONS HAVE BEEN TAKEN TO CONTROL THE COST OF**  
4 **EMPLOYEE BENEFITS?**

5 A. On an ongoing basis, AEP reviews its employee benefits to manage costs, while  
6 continuing to provide benefits that are sufficient to attract and retain employees.  
7 Periodically, benefit plan changes are made, and other steps are taken to control costs.  
8 In recent years, this included the 2023 implementation of a healthcare navigation and  
9 advocacy provider embedded within our medical plan, designed to support employees  
10 in managing their healthcare journeys. This initiative simplifies access to care and  
11 improves overall health outcomes. In 2024, AEP introduced a new Employee  
12 Assistance Plan ("EAP") that offers 12 different modalities for accessing mental health  
13 services, further promoting employee well-being. These enhancements are designed to  
14 elevate the overall employment experience for our employees, reduce preventable  
15 diseases, and lower associated costs.

16 AEP benefit contracts generally cover a one-to-three-year period. AEP  
17 routinely reviews and evaluates these contracts to ensure they are market competitive.  
18 AEP, in conjunction with benefit consultants, Mercer or Aon in past years, and Willis  
19 Towers Watson, solicit and evaluate proposals to ensure the benefits contracts meet  
20 performance expectations and are competitively priced.

21 Finally, AEP is also an active member of the Health Action Council of Ohio,  
22 which is a group of multi-state employers that work to extend group purchasing power  
23 to affect the delivery and price of healthcare services in the states in which they operate.

1   **Q.    WHAT WERE KENTUCKY POWER’S CONTRIBUTIONS RELATED TO**  
2   **THE EMPLOYEE BENEFIT PLANS DURING THE TEST YEAR?**

3   A.    Kentucky Power is requesting inclusion of \$6,021,381 of direct net employee group  
4   benefit cost in its cost-of-service. This includes medical, dental, life insurance,  
5   accidental death and disability, and long-term disability costs. This is a reduction of  
6   \$101,519 from the test year amount due to lower calculated 2025 benefit expense  
7   projection. The adjustment to decrease net employee-related group benefit expense  
8   (W27) is supported by Company Witness Ciborek. Exhibit ARC-9 illustrates the per  
9   employee monthly AEP and employee contributions for healthcare benefits.

10   **Q.   HOW DOES AEP DETERMINE THAT THE EMPLOYEE BENEFIT**  
11   **PROGRAMS THAT IT OFFERS ARE REASONABLE AND NECESSARY?**

12   A.    AEP evaluates its employee benefits by comparing them with those offered by other  
13   utility companies. This benchmarking ensures AEP remains competitive in attracting  
14   talent. Potential applicants and current employees may pursue job opportunities within  
15   the energy services job market or in a broad business and industrial job market;  
16   therefore, AEP’s provision of benefits that is competitive with these labor markets is  
17   necessary to attract and retain suitably qualified and experienced employees and job  
18   candidates.

19   **Q.   HOW ARE BENEFIT VENDORS SELECTED?**

20   A.    As each contract renewal approaches, the vendor is asked for a formal proposal to cover  
21   the renewal period. These proposals are reviewed internally, and in most cases by one  
22   of the independent third-party consultants, to set the performance standards and  
23   determine if the contract proposal is market competitive. If the proposal does not meet

1 our performance expectations or is not competitively priced, requests for proposals are  
2 sent to qualified vendors and a final vendor is selected through a competitive bid  
3 process.

4 **Q. PLEASE DESCRIBE HOW THE VALUE OF AEP'S BENEFIT PROGRAM IS**  
5 **ASSESSED.**

6 A. AEP compares benefit values from peer companies to help determine the  
7 reasonableness of the benefits offered. This is done using the Aon Benefits Index  
8 Report, which compares individual benefit programs offered by AEP to those offered  
9 by other utility-specific employers. The Benefit Index assigns a value to the benefits  
10 provided by participating companies based on a detailed analysis and valuation of the  
11 benefit offered. The Benefit Index's comparative analysis expresses the relative value  
12 of an individual company's benefit plan as an index calculated by dividing AEP's  
13 actuarial benefit plan value by the average actuarial benefit plan value for all the  
14 companies included in the comparison. Neither the cost to provide such benefits, nor  
15 the contributions required from employees, is factored into this comparison.

16 **Q. WHAT DO THESE METRICS AND VALUE COMPARISONS SHOW?**

17 A. Confidential Exhibit ARC-10, an excerpt from the 2025 Aon Benefit Index Relative  
18 Value report, shows that the total value of employee benefits offered to employees is  
19 consistent with market practices. Specifically, for salaried employees, the value of  
20 employee benefits provided, had an Index Value of 99.4, which is very close to the  
21 average value provided by peer companies and was between fourth and fifth place out  
22 of 11 utility industry survey participants, excluding AEP. This study also found that  
23 the value AEP provides for All Active Employee Healthcare was slightly below



1 average at 99.4 compared to the 100.0 for the average of the comparator group (see  
2 Confidential Exhibit ARC-10, page 4). Confidential Exhibit ARC-11 illustrates that  
3 AEP's medical costs are in line with the utility industry.

4 These exhibits demonstrate that the employee benefits offered to AEP system  
5 employees are comparable to the average value offered by peer companies.  
6 Furthermore, these exhibits show that the Companies' employee benefits are  
7 reasonable, competitive, efficient and consistent with that of other similarly sized utility  
8 industry employers. This enables Kentucky Power to attract and retain suitably  
9 experienced and qualified employees.

#### **X. CONCLUSION**

10 **Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.**

11 A. I have shown that the employee compensation Kentucky Power seeks to include in this  
12 case is fair, reasonable, and benefits customers by ensuring adequate staffing for  
13 serving customers at a reasonable cost. I have shown that employee compensation is  
14 within a reasonable market competitive range and that market competitive  
15 compensation is required to attract and retain the knowledgeable, experienced, and  
16 qualified employees needed to provide reliable electric services to customers safely,  
17 efficiently, and effectively. I have also demonstrated that the Company's Incentive  
18 Compensation is designed to minimize overall expenses, which reduces the  
19 cost-of-service to customers. The compensation the Company provides, inclusive of  
20 Base Pay, STI and, for some positions, LTI compensation is a reasonable, necessary,  
21 and prudent cost of providing service to customers. Therefore, I recommend the

1 requests levels of Incentive Compensation be included in Kentucky Power's  
2 cost-of-service for all positions.

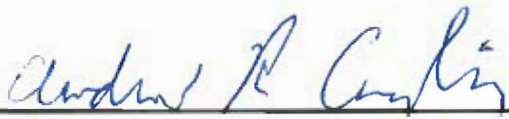
3 I have also demonstrated that the cost of the Company's employee benefits is  
4 reasonable and market competitive and should also be included in Kentucky Power's  
5 cost-of-service.

6 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

7 A. Yes, it does.

## VERIFICATION

The undersigned, Andrew R. Carlin, being duly sworn, deposes and says he is the Director of Compensation and Executive Benefits, 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.

  
\_\_\_\_\_  
Andrew R. Carlin

State of Ohio )  
\_\_\_\_\_) Case No. 2025-00257  
\_\_\_\_\_) )

Subscribed and sworn to before me, a Notary Public in and before said County  
and State, by Andrew R. Carlin, on August 21, 2025.

  
\_\_\_\_\_  
Notary Public

My Commission Expires \_\_\_\_\_

Notary ID Number \_\_\_\_\_



## **Surveys Completed and Used for Compensation Comparisons**

### Willis Towers Watson U.S. Compensation Data Bank (CDB):

2024 Energy Services Industry - Executive Compensation Survey Report – U.S., inclusive of AEP custom peer group and AEP broad peer group reports

2024 Energy Services Industry - Middle Management, Professional & Support Compensation Survey Report – U.S.

2024 General Industry - Executive Compensation Survey Report – U.S.

2024 General Industry - Middle Management, Professional and Support Compensation Survey Report – U.S.

## KPCO and AEPSC Compensation vs. Market Competitive Compensation for All Physical &amp; Craft Positions

					Survey Results <sup>1</sup>			% Difference	
Job Identifier <sup>2</sup>	Incumbent Count	Avg Annualized Base Pay	Target Annual Incentive <sup>3</sup>	Target TCC	Base	Target Incentive	Target TCC	AEP Target TCC vs. Survey Target TCC <sup>4</sup>	AEP Base vs. Survey Target TCC <sup>4</sup>
KPCO									
KPCO1	2	\$74,797	\$2,244	\$77,041	\$82,119	\$2,985	\$85,104	-9.5%	-12.1%
KPCO2	4	\$71,386	\$2,142	\$73,527	\$82,119	\$2,985	\$85,104	-13.6%	-16.1%
KPCO3	3	\$74,797	\$2,244	\$77,041	\$82,119	\$2,985	\$85,104	-9.5%	-12.1%
KPCO4	2	\$81,058	\$2,432	\$83,489	\$76,421	\$2,946	\$79,367	5.2%	2.1%
KPCO5	1	\$99,486	\$2,985	\$102,471	\$98,062	\$7,057	\$105,119	-2.5%	-5.4%
KPCO6	4	\$107,182	\$3,215	\$110,398	\$106,811	\$9,111	\$115,922	-4.8%	-7.5%
KPCO7	2	\$76,024	\$2,281	\$78,305	\$95,614	\$1,876	\$97,490	-19.7%	-22.0%
KPCO8	4	\$79,503	\$2,385	\$81,888	\$95,614	\$1,876	\$97,490	-16.0%	-18.5%
KPCO9	1	\$81,994	\$2,460	\$84,453	\$75,856	\$7,016	\$82,872	1.9%	-1.1%
KPCO10	1	\$75,317	\$2,260	\$77,576	\$72,254	\$3,671	\$75,925	2.2%	-0.8%
KPCO11	2	\$75,317	\$2,260	\$77,576	\$72,254	\$3,671	\$75,925	2.2%	-0.8%
KPCO12	2	\$75,317	\$2,260	\$77,576	\$72,254	\$3,671	\$75,925	2.2%	-0.8%
KPCO13	4	\$110,989	\$3,330	\$114,318	\$109,173	\$4,224	\$113,397	0.8%	-2.1%
KPCO14	13	\$110,989	\$3,330	\$114,318	\$109,173	\$4,224	\$113,397	0.8%	-2.1%
KPCO15	1	\$106,829	\$3,205	\$110,034	\$109,173	\$4,224	\$113,397	-3.0%	-5.8%
KPCO16	1	\$106,829	\$3,205	\$110,034	\$109,173	\$4,224	\$113,397	-3.0%	-5.8%
KPCO17	2	\$85,394	\$2,562	\$87,956	\$109,173	\$4,224	\$113,397	-22.4%	-24.7%
KPCO18	1	\$106,829	\$3,205	\$110,034	\$109,173	\$4,224	\$113,397	-3.0%	-5.8%
KPCO19	4	\$89,185	\$2,676	\$91,861	\$90,748	\$2,723	\$93,471	-1.7%	-4.6%
KPCO20	2	\$89,918	\$2,698	\$92,616	\$90,748	\$2,723	\$93,471	-0.9%	-3.8%
KPCO Incumbents:	56								
KPCO Matched Job Count:	20					KPCO Average:		-4.7%	-7.5%
AEPSC									
AEPSC1	1	\$99,486	\$2,985	\$102,471	\$98,062	\$7,137	\$105,199	-2.6%	-5.4%
AEPSC2	4	\$95,961	\$2,879	\$98,840	\$98,062	\$7,137	\$105,199	-6.0%	-8.8%
AEPSC3	13	\$95,875	\$2,876	\$98,751	\$98,062	\$7,137	\$105,199	-6.1%	-8.9%
AEPSC4	4	\$97,053	\$2,912	\$99,964	\$98,062	\$7,137	\$105,199	-5.0%	-7.7%
AEPSC5	5	\$97,053	\$2,912	\$99,964	\$98,062	\$7,137	\$105,199	-5.0%	-7.7%
AEPSC6	2	\$80,787	\$2,424	\$83,211	\$104,539	\$3,096	\$107,635	-22.7%	-24.9%
AEPSC7	6	\$96,730	\$2,902	\$99,632	\$104,539	\$3,096	\$107,635	-7.4%	-10.1%
AEPSC8	1	\$110,989	\$3,330	\$114,318	\$109,173	\$4,224	\$113,397	0.8%	-2.1%
AEPSC9	1	\$108,285	\$3,249	\$111,533	\$109,173	\$4,224	\$113,397	-1.6%	-4.5%
AEPSC10	14	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC11	4	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC12	2	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC13	3	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC14	6	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC15	1	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC16	5	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC17	3	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC18	4	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC19	4	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC20	8	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC21	5	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC22	7	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC23	4	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC24	2	\$108,285	\$3,249	\$111,533	\$105,866	\$6,216	\$112,082	-0.5%	-3.4%
AEPSC25	2	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC26	3	\$110,989	\$3,330	\$114,318	\$105,866	\$6,216	\$112,082	2.0%	-1.0%
AEPSC27	19	\$110,989	\$3,330	\$114,318	\$109,173	\$4,224	\$113,397	0.8%	-2.1%
AEPSC28	4	\$110,989	\$3,330	\$114,318	\$109,173	\$4,224	\$113,397	0.8%	-2.1%
AEPSC29	30	\$108,285	\$3,249	\$111,533	\$109,173	\$4,224	\$113,397	-1.6%	-4.5%
AEPSC30	14	\$118,498	\$3,555	\$122,053	\$110,811	\$3,994	\$114,805	6.3%	3.2%
AEPSC31	12	\$115,606	\$3,468	\$119,075	\$110,811	\$3,994	\$114,805	3.7%	0.7%
AEPSC32	9	\$115,606	\$3,468	\$119,075	\$110,811	\$3,994	\$114,805	3.7%	0.7%
AEPSC Incumbents	202					AEPSC Average:		-0.9%	-3.8%
AEPSC Matched Job Count	32								
Grand Average:								-2.3%	-5.2%
GRAND TOTAL INCUMBENTS:		258	% of Jobs Below Market Competitive Range <sup>3</sup>					9.6%	15.4%
GRAND TOTAL JOB COUNT:		52	% of Jobs Above Market Competitive Range <sup>3</sup>					0.0%	0.0%

**Notes**

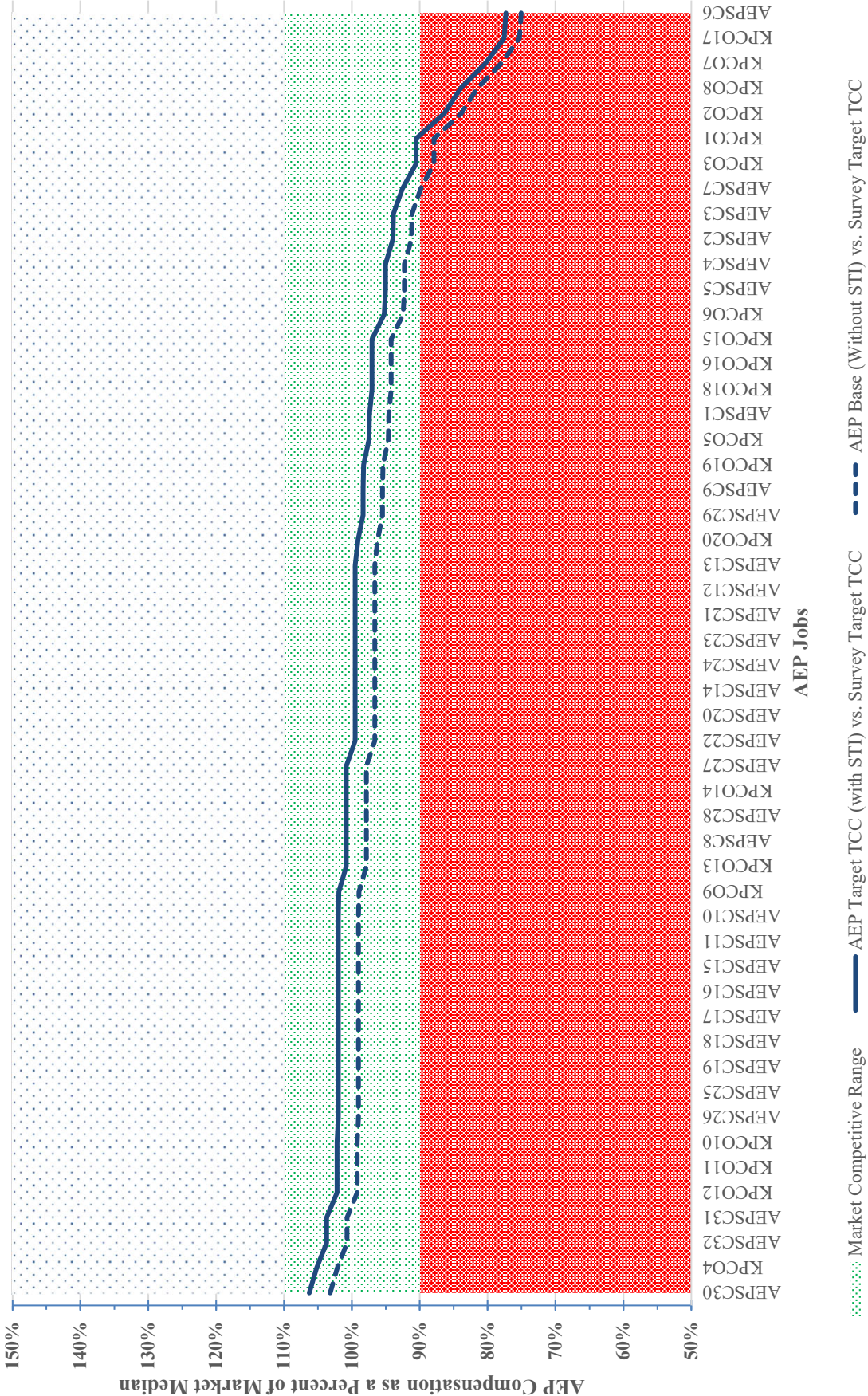
<sup>1</sup> Survey Data from April 2024 Towers Watson Energy Services and General Industry Middle Management, Professional & Support surveys, aged to May 31, 2025 at a 2.5% annual rate.

<sup>2</sup> Includes all Kentucky Power Company and AEPSC jobs for which there was a matching survey job with a sufficient sample of compensation survey information as of May 31, 2025.

<sup>3</sup> Target payout is 3% of base earnings for all physical and craft jobs shown.

<sup>4</sup> A market competitive range of +/- 10 percent has been used for all physical and craft positions.

Table ARC-4  
KPCO & AEPSC Physical and Craft Positions  
vs. Market-Competitive Compensation (High to Low)  
With and Without STI



<u>Job Identifier2</u>	AEP Target TCC (with STI) vs. Survey Target TCC	AEP Base (Without STI) vs. Survey Target TCC	Below Market	Market Median	Market Competitive Range	Above Market
AEPSC30	106.3%	103.2%	90.0%	100.0%	20.0%	40.0%
KPCO4	105.2%	102.1%	90.0%	100.0%	20.0%	40.0%
AEPSC32	103.7%	100.7%	90.0%	100.0%	20.0%	40.0%
AEPSC31	103.7%	100.7%	90.0%	100.0%	20.0%	40.0%
KPCO12	102.2%	99.2%	90.0%	100.0%	20.0%	40.0%
KPCO11	102.2%	99.2%	90.0%	100.0%	20.0%	40.0%
KPCO10	102.2%	99.2%	90.0%	100.0%	20.0%	40.0%
AEPSC26	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC25	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC19	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC18	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC17	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC16	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC15	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC11	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
AEPSC10	102.0%	99.0%	90.0%	100.0%	20.0%	40.0%
KPCO9	101.9%	98.9%	90.0%	100.0%	20.0%	40.0%
KPCO13	100.8%	97.9%	90.0%	100.0%	20.0%	40.0%
AEPSC8	100.8%	97.9%	90.0%	100.0%	20.0%	40.0%
AEPSC28	100.8%	97.9%	90.0%	100.0%	20.0%	40.0%
KPCO14	100.8%	97.9%	90.0%	100.0%	20.0%	40.0%
AEPSC27	100.8%	97.9%	90.0%	100.0%	20.0%	40.0%
AEPSC22	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEPSC20	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEPSC14	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEPSC24	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEPSC23	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEPSC21	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEPSC12	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEPSC13	99.5%	96.6%	90.0%	100.0%	20.0%	40.0%
KPCO20	99.1%	96.2%	90.0%	100.0%	20.0%	40.0%
AEPSC29	98.4%	95.5%	90.0%	100.0%	20.0%	40.0%
AEPSC9	98.4%	95.5%	90.0%	100.0%	20.0%	40.0%
KPCO19	98.3%	95.4%	90.0%	100.0%	20.0%	40.0%
KPCO5	97.5%	94.6%	90.0%	100.0%	20.0%	40.0%
AEPSC1	97.4%	94.6%	90.0%	100.0%	20.0%	40.0%
KPCO18	97.0%	94.2%	90.0%	100.0%	20.0%	40.0%
KPCO16	97.0%	94.2%	90.0%	100.0%	20.0%	40.0%
KPCO15	97.0%	94.2%	90.0%	100.0%	20.0%	40.0%
KPCO6	95.2%	92.5%	90.0%	100.0%	20.0%	40.0%
AEPSC5	95.0%	92.3%	90.0%	100.0%	20.0%	40.0%
AEPSC4	95.0%	92.3%	90.0%	100.0%	20.0%	40.0%
AEPSC2	94.0%	91.2%	90.0%	100.0%	20.0%	40.0%
AEPSC3	93.9%	91.1%	90.0%	100.0%	20.0%	40.0%
AEPSC7	92.6%	89.9%	90.0%	100.0%	20.0%	40.0%
KPCO3	90.5%	87.9%	90.0%	100.0%	20.0%	40.0%
KPCO1	90.5%	87.9%	90.0%	100.0%	20.0%	40.0%
KPCO2	86.4%	83.9%	90.0%	100.0%	20.0%	40.0%
KPCO8	84.0%	81.5%	90.0%	100.0%	20.0%	40.0%
KPCO7	80.3%	78.0%	90.0%	100.0%	20.0%	40.0%
KPCO17	77.6%	75.3%	90.0%	100.0%	20.0%	40.0%
AEPSC6	77.3%	75.1%	90.0%	100.0%	20.0%	40.0%





		Incumbent Data			Survey Results <sup>1</sup>			% Difference	
Job Identifier <sup>2</sup>	Incumbent Count	Avg Base	Target Incentive	Target TCC	Base	Target Incentive	Target TCC	Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>
GRAND TOTAL JOB COUNT:		50			% of Jobs Above Market Competitive Range <sup>3</sup>			18%	6%

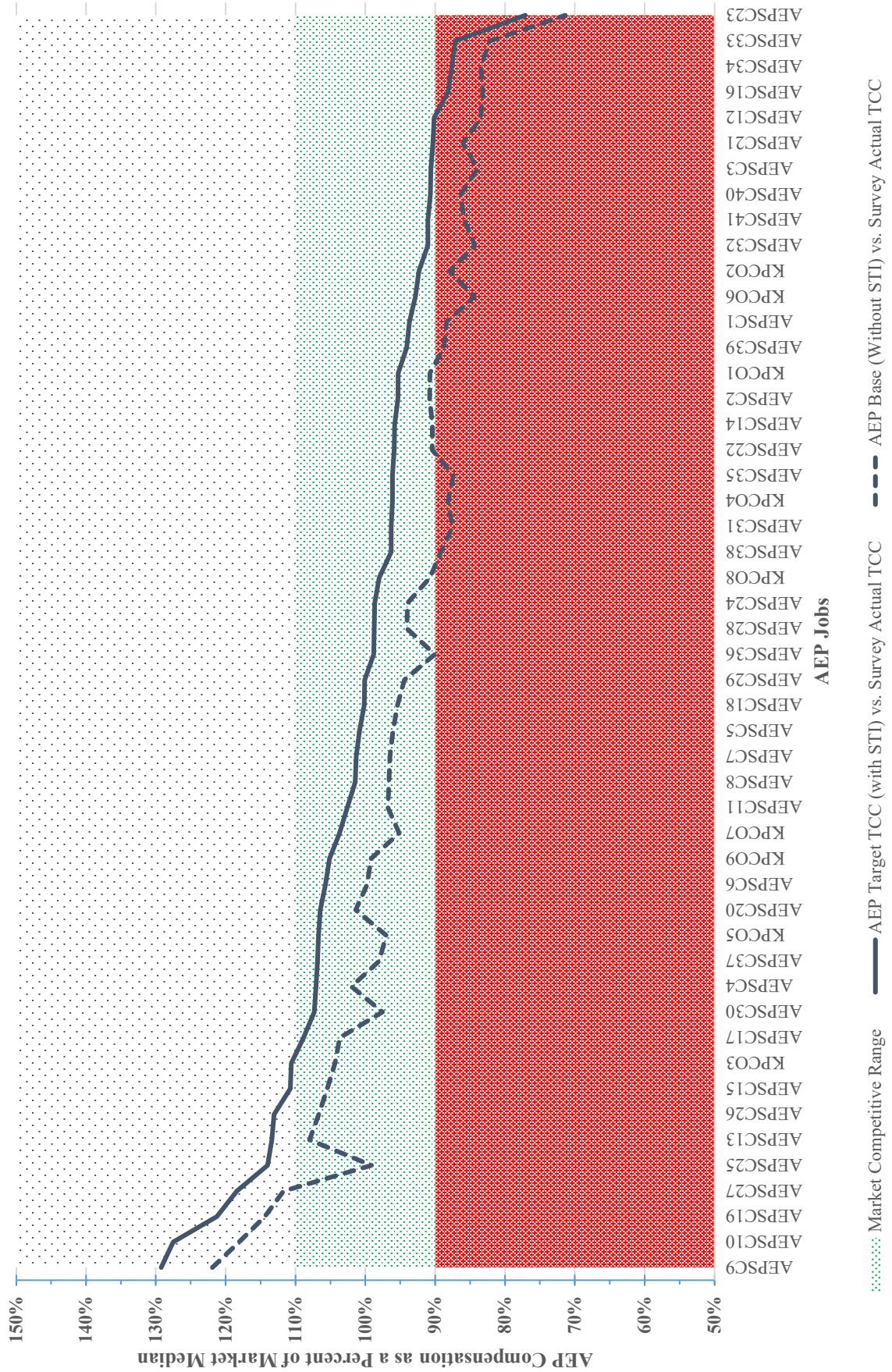
**Notes:**

<sup>1</sup> Survey Data from the 2024 Willis Towers Watson Energy Services and General Industry Middle Management, Professional & Support surveys, aged from April 1, 2024 to May 31, 2025 at 3.5% annual rate.

<sup>2</sup> Includes all Kentucky Power Company and AEPSC jobs as of May 31, 2024 for which there was a matching survey job with a sufficient sample of compensation survey information.

<sup>3</sup> A market competitive range of +/- 10 percent has been used for these salaried nonexempt positions.

# KPCO and AEPSC Salaried Nonexempt Positions vs. Market-Competitive Compensation (High to Low) With and Without AEP STI



<b>AEP Job</b>	<b>AEP Target TCC (with STI) vs. Survey Actual TCC</b>	<b>AEP Base (Without STI) vs. Survey Actual TCC</b>	<b>Market Low</b>	<b>Market Median Compensation</b>	<b>Market Competitive Range</b>	<b>Market Max</b>
AEpsc9	129.2%	121.9%	90.0%	100.0%	20.0%	40.0%
AEpsc10	127.5%	118.1%	90.0%	100.0%	20.0%	40.0%
AEpsc19	121.2%	114.4%	90.0%	100.0%	20.0%	40.0%
AEpsc27	118.4%	111.7%	90.0%	100.0%	20.0%	40.0%
AEpsc25	114.0%	99.1%	90.0%	100.0%	20.0%	40.0%
AEpsc13	113.4%	108.0%	90.0%	100.0%	20.0%	40.0%
AEpsc26	113.1%	106.7%	90.0%	100.0%	20.0%	40.0%
AEpsc15	110.7%	105.5%	90.0%	100.0%	20.0%	40.0%
KPCo3	110.6%	104.3%	90.0%	100.0%	20.0%	40.0%
AEpsc17	108.9%	103.7%	90.0%	100.0%	20.0%	40.0%
AEpsc30	107.3%	97.6%	90.0%	100.0%	20.0%	40.0%
AEpsc4	107.1%	102.0%	90.0%	100.0%	20.0%	40.0%
AEpsc37	106.8%	98.0%	90.0%	100.0%	20.0%	40.0%
KPCo5	106.7%	97.0%	90.0%	100.0%	20.0%	40.0%
AEpsc20	106.4%	101.4%	90.0%	100.0%	20.0%	40.0%
AEpsc6	105.7%	99.7%	90.0%	100.0%	20.0%	40.0%
KPCo9	105.1%	99.2%	90.0%	100.0%	20.0%	40.0%
KPCo7	103.7%	95.1%	90.0%	100.0%	20.0%	40.0%
AEpsc11	102.6%	96.8%	90.0%	100.0%	20.0%	40.0%
AEpsc8	101.5%	96.6%	90.0%	100.0%	20.0%	40.0%
AEpsc7	101.3%	96.5%	90.0%	100.0%	20.0%	40.0%
AEpsc5	100.8%	96.0%	90.0%	100.0%	20.0%	40.0%
AEpsc18	100.2%	95.4%	90.0%	100.0%	20.0%	40.0%
AEpsc29	100.1%	94.4%	90.0%	100.0%	20.0%	40.0%
AEpsc36	98.8%	90.0%	90.0%	100.0%	20.0%	40.0%
AEpsc28	98.7%	94.0%	90.0%	100.0%	20.0%	40.0%
AEpsc24	98.7%	94.0%	90.0%	100.0%	20.0%	40.0%
KPCo8	98.0%	90.7%	90.0%	100.0%	20.0%	40.0%
AEpsc38	96.3%	89.2%	90.0%	100.0%	20.0%	40.0%
AEpsc31	96.3%	87.5%	90.0%	100.0%	20.0%	40.0%
KPCo4	96.1%	88.2%	90.0%	100.0%	20.0%	40.0%
AEpsc35	96.1%	87.4%	90.0%	100.0%	20.0%	40.0%
AEpsc22	95.9%	90.4%	90.0%	100.0%	20.0%	40.0%
AEpsc14	95.8%	90.4%	90.0%	100.0%	20.0%	40.0%
AEpsc2	95.3%	90.8%	90.0%	100.0%	20.0%	40.0%
KPCo1	95.3%	90.7%	90.0%	100.0%	20.0%	40.0%
AEpsc39	94.1%	88.8%	90.0%	100.0%	20.0%	40.0%
AEpsc1	93.7%	88.4%	90.0%	100.0%	20.0%	40.0%
KPCo6	92.8%	84.4%	90.0%	100.0%	20.0%	40.0%
KPCo2	92.3%	87.9%	90.0%	100.0%	20.0%	40.0%
AEpsc32	91.0%	84.3%	90.0%	100.0%	20.0%	40.0%
AEpsc41	91.0%	85.9%	90.0%	100.0%	20.0%	40.0%
AEpsc40	90.7%	86.4%	90.0%	100.0%	20.0%	40.0%

AEPSC3	90.6%	83.9%	90.0%	100.0%	20.0%	40.0%
AEPSC21	90.3%	86.0%	90.0%	100.0%	20.0%	40.0%
AEPSC12	90.1%	83.5%	90.0%	100.0%	20.0%	40.0%
AEPSC16	88.2%	83.2%	90.0%	100.0%	20.0%	40.0%
AEPSC34	87.6%	83.4%	90.0%	100.0%	20.0%	40.0%
AEPSC33	87.1%	82.2%	90.0%	100.0%	20.0%	40.0%
AEPSC23	77.1%	71.4%	90.0%	100.0%	20.0%	40.0%

## KPCO &amp; AEPSC Compensation for Exempt Non-Officer Positions Versus Market

		AEP Incumbent Data					Survey Results <sup>1</sup>					% Difference	
Job Identifier <sup>2</sup>	Incumbent Count	Avg Base	Target Short-Term Incentive (STI)	Target Total Cash Compensation (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)	Base	Target STI	Target TCC	Long-Term Incentive (LTI)	Target TC	Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>
KPCO													
KPCO1	2	\$88,888	\$ 8,000	\$96,888	\$ -	\$96,888	\$98,187	\$4,258	\$102,445	\$ -	\$102,445	-5.4%	-13.2%
KPCO2	1	\$132,281	\$ 19,842	\$152,123	\$ -	\$152,123	\$154,021	\$9,309	\$163,330	\$ 139	\$163,469	-6.9%	-19.1%
KPCO3	1	\$120,870	\$ 12,087	\$132,957	\$ -	\$132,957	\$121,644	\$6,098	\$127,742	\$ 20	\$127,762	4.1%	-5.4%
KPCO4	1	\$128,000	\$ 12,800	\$140,800	\$ -	\$140,800	\$128,583	\$2,461	\$131,044	\$ 1,921	\$132,965	5.9%	-3.7%
KPCO5	1	\$68,092	\$ 5,447	\$73,540	\$ -	\$73,540	\$70,296	\$824	\$71,120	\$ -	\$71,120	3.4%	-4.3%
KPCO6	1	\$94,000	\$ 9,400	\$103,400	\$ -	\$103,400	\$100,842	\$1,796	\$102,638	\$ (35)	\$102,603	0.8%	-8.4%
KPCO7	1	\$66,524	\$ 5,322	\$71,846	\$ -	\$71,846	\$74,518	-\$273	\$74,245	\$ -	\$74,245	-3.2%	-10.4%
KPCO8	1	\$75,000	\$ 6,750	\$81,750	\$ -	\$81,750	\$87,363	\$6,993	\$94,356	\$ -	\$94,356	-13.4%	-20.5%
KPCO9	1	\$108,150	\$ 10,815	\$118,965	\$ -	\$118,965	\$129,859	\$6,056	\$135,915	\$ -	\$135,915	-12.5%	-20.4%
KPCO10	1	\$156,664	\$ 31,333	\$187,996	\$ 7,000	\$194,996	\$185,873	\$35,419	\$221,292	\$ 10,717	\$232,009	-16.0%	-32.5%
KPCO11	1	\$191,911	\$ 47,978	\$239,888	\$ 25,000	\$264,888	\$177,842	\$26,480	\$204,322	\$ 2,110	\$206,432	28.3%	-7.0%
KPCO12	1	\$132,510	\$ 19,877	\$152,387	\$ -	\$152,387	\$145,857	\$25,426	\$171,283	\$ 228	\$171,511	-11.2%	-22.7%
KPCO13	1	\$80,378	\$ 7,234	\$87,611	\$ -	\$87,611	\$90,849	\$6,090	\$96,939	\$ 1,563	\$98,502	-11.1%	-18.4%
KPCO14	3	\$87,958	\$ 8,796	\$96,754	\$ -	\$96,754	\$107,019	\$13,160	\$120,179	\$ (392)	\$119,787	-19.2%	-26.6%
KPCO15	1	\$99,742	\$ 9,974	\$109,716	\$ -	\$109,716	\$134,716	\$13,331	\$148,047	\$ (493)	\$147,554	-25.6%	-32.4%
KPCO16	1	\$126,508	\$ 12,651	\$139,159	\$ -	\$139,159	\$124,882	\$7,862	\$132,744	\$ 359	\$133,103	4.5%	-5.0%
KPCO17	1	\$80,819	\$ 6,466	\$87,285	\$ -	\$87,285	\$78,051	-\$473	\$77,578	\$ 372	\$77,950	12.0%	3.7%
KPCO18	1	\$94,428	\$ 9,443	\$103,871	\$ -	\$103,871	\$118,824	\$14,385	\$133,209	\$ -	\$133,209	-22.0%	-29.1%
KPCO19	3	\$130,965	\$ 13,096	\$144,061	\$ -	\$144,061	\$134,461	\$17,625	\$152,086	\$ -	\$152,086	-5.3%	-13.9%
KPCO20	1	\$124,592	\$ 18,689	\$143,281	\$ -	\$143,281	\$123,867	\$4,769	\$128,636	\$ 2,500	\$131,136	9.3%	-5.0%
KPCO21	3	\$124,633	\$ 18,695	\$143,328	\$ -	\$143,328	\$130,564	\$11,398	\$141,962	\$ 3,773	\$145,735	-1.7%	-14.5%
KPCO22	1	\$142,623	\$ 28,525	\$171,148	\$ 7,000	\$178,148	\$165,556	\$27,264	\$192,820	\$ 4,525	\$197,345	-9.7%	-27.7%
KPCO23	1	\$91,800	\$ 9,180	\$100,980	\$ -	\$100,980	\$107,601	\$10,746	\$118,347	\$ 707	\$119,054	-15.2%	-22.9%
KPCO24	1	\$112,200	\$ 11,220	\$123,420	\$ -	\$123,420	\$135,578	\$18,593	\$154,171	\$ (26)	\$154,145	-19.9%	-27.2%
KPCO25	2	\$86,841	\$ 7,816	\$94,657	\$ -	\$94,657	\$101,002	\$9,938	\$110,940	\$ 1,830	\$112,770	-16.1%	-23.0%
KPCO26	2	\$71,123	\$ 5,690	\$76,813	\$ -	\$76,813	\$77,277	\$4,619	\$81,896	\$ 40	\$81,936	-6.3%	-13.2%
KPCO27	2	\$57,867	\$ 3,472	\$61,339	\$ -	\$61,339	\$64,678	\$4,179	\$68,857	\$ -	\$68,857	-10.9%	-16.0%
KPCO28	1	\$125,028	\$ 18,754	\$143,782	\$ -	\$143,782	\$142,659	\$26,483	\$169,142	\$ -	\$169,142	-15.0%	-26.1%
KPCO29	1	\$160,158	\$ 24,024	\$184,181	\$ -	\$184,181	\$136,615	\$8,652	\$145,267	\$ 338	\$145,605	26.5%	10.0%
KPCO30	1	\$108,347	\$ 10,835	\$119,182	\$ -	\$119,182	\$109,752	\$4,922	\$114,674	\$ (164)	\$114,510	4.1%	-5.4%
KPCO31	1	\$122,094	\$ 12,209	\$134,304	\$ -	\$134,304	\$136,615	\$8,652	\$145,267	\$ 338	\$145,605	-7.8%	-16.1%
KPCO32	1	\$86,000	\$ 7,740	\$93,740	\$ -	\$93,740	\$87,724	\$4,870	\$92,594	\$ -	\$92,594	1.2%	-7.1%
KPCO33	2	\$115,988	\$ 11,599	\$127,586	\$ -	\$127,586	\$121,344	\$15,236	\$136,580	\$ 378	\$136,958	-6.8%	-15.3%
KPCO34	1	\$128,624	\$ 19,294	\$147,918	\$ -	\$147,918	\$153,273	\$27,306	\$180,579	\$ (745)	\$179,834	-17.7%	-28.5%
KPCO35	1	\$110,719	\$ 11,072	\$121,791	\$ -	\$121,791	\$127,585	\$15,400	\$142,985	\$ 47	\$143,032	-14.9%	-22.6%
KPCO36	1	\$121,250	\$ 12,125	\$133,375	\$ -	\$133,375	\$127,398	\$13,194	\$140,592	\$ -	\$140,592	-5.1%	-13.8%
KPCO37	4	\$105,217	\$ 10,522	\$115,739	\$ -	\$115,739	\$120,555	\$12,781	\$133,336	\$ -	\$133,336	-13.2%	-21.1%
KPCO38	1	\$91,250	\$ 6,388	\$97,638	\$ -	\$97,638	\$120,555	\$12,781	\$133,336	\$ -	\$133,336	-26.8%	-31.6%
KPCO39	2	\$79,760	\$ 5,991	\$85,751	\$ -	\$85,751	\$100,564	\$9,673	\$110,237	\$ -	\$110,237	-22.2%	-27.6%
KPCO40	1	\$74,491	\$ 5,959	\$80,450	\$ -	\$80,450	\$78,297	\$6,720	\$85,017	\$ -	\$85,017	-5.4%	-12.4%
KPCO41	1	\$64,260	\$ 5,141	\$69,401	\$ -	\$69,401	\$78,297	\$6,720	\$85,017	\$ -	\$85,017	-18.4%	-24.4%
KPCO42	1	\$182,310	\$ 45,578	\$227,888	\$ 25,000	\$252,888	\$198,559	\$42,907	\$241,466	\$ 17,274	\$258,740	-2.3%	-29.5%
KPCO43	1	\$170,568	\$ 42,642	\$213,210	\$ 25,000	\$238,210	\$174,109	\$19,458	\$193,567	\$ -	\$193,567	23.1%	-11.9%
KPCO44	2	\$160,251	\$ 32,050	\$192,301	\$ 7,000	\$199,301	\$174,498	\$35,597	\$210,095	\$ 10,126	\$220,221	-9.5%	-27.2%
KPCO45	2	\$105,135	\$ 10,514	\$115,649	\$ -	\$115,649	\$115,765	\$12,303	\$128,068	\$ 356	\$128,424	-9.9%	-18.1%
KPCO46	3	\$105,706	\$ 10,571	\$116,276	\$ -	\$116,276	\$115,765	\$12,303	\$128,068	\$ 356	\$128,424	-9.5%	-17.7%
KPCO47	2	\$87,591	\$ 7,883	\$95,474	\$ -	\$95,474	\$94,075	\$11,242	\$105,317	\$ (744)	\$104,573	-8.7%	-16.2%
KPCO48	3	\$138,398	\$ 20,760	\$159,158	\$ -	\$159,158	\$127,585	\$15,400	\$142,985	\$ 47	\$143,032	11.3%	-3.2%
KPCO49	1	\$55,193	\$ 3,312	\$58,505	\$ -	\$58,505	\$69,932	\$4,996	\$74,928	\$ 41	\$74,969	-22.0%	-26.4%
KPCO Incumbent Count:		71											
KPCO Job Count:		49									KPCO Average:	-6.4%	-17.0%
AEPSC													
AEPSC1	18	\$ 86,772	\$7,809	\$94,581	\$0	\$ 94,581	\$98,187	\$4,258	\$102,445	\$0	\$102,445	-7.7%	-15.3%
AEPSC2	11	\$ 75,267	\$6,021	\$81,288	\$0	\$ 81,288	\$85,175	\$3,358	\$88,533	\$0	\$88,533	-8.2%	-15.0%
AEPSC3	46	\$119,229	\$11,923	\$131,152	\$0	\$131,152	\$121,644	\$6,098	\$127,742	\$20	\$127,762	2.7%	-6.7%
AEPSC4	3	\$147,714	\$29,543	\$177,257	\$7,000	\$184,257	\$185,560	\$13,947	\$199,507	\$612	\$200,119	-7.9%	-26.2%
AEPSC5	1	\$142,125	\$21,319	\$163,444	\$0	\$163,444	\$167,293	\$6,605	\$173,898	\$9,810	\$183,708	-11.0%	-22.6%
AEPSC6	135	\$ 85,962	\$7,737	\$93,698	\$0	\$ 93,698	\$98,187	\$4,258	\$102,445	\$0	\$102,445	-8.5%	-16.1%
AEPSC7	56	\$ 80,072	\$6,406	\$86,478	\$0	\$ 86,478	\$85,175	\$3,358	\$88,533	\$0	\$88,533	-2.3%	-9.6%
AEPSC8	137	\$138,855	\$20,828	\$159,683	\$0	\$159,683	\$154,021	\$9,309	\$163,330	\$139	\$163,469	-2.3%	-15.1%
AEPSC9	213	\$116,686	\$11,669	\$128,354	\$0	\$128,354	\$121,644	\$6,098	\$127,742	\$20	\$127,762	0.5%	-8.7%
AEPSC10	48	\$161,855	\$32,371	\$194,226	\$7,000	\$ 201,226	\$175,148	\$17,772	\$192,920	\$1,063	\$193,983	3.7%	-16.6%
AEPSC11	5	\$123,289	\$18,493	\$141,782	\$0	\$141,782	\$142,015	\$5,893	\$147,908	\$0	\$147,908	-4.1%	-16.6%
AEPSC12	2	\$104,272	\$10,427	\$114,699	\$0	\$114,699	\$112,668	\$4,303	\$116,971	\$0	\$116,971	-1.9%	-10.9%
AEPSC13	1	\$112,888	\$11,289	\$124,177	\$0	\$124,177	\$145,047	\$18,461	\$163,508	-\$722	\$162,786	-23.7%	-30.7%
AEPSC14	8	\$ 86,017	\$7,742	\$93,758	\$0	\$ 93,758	\$74,409	\$1,162	\$75,571	\$0	\$75,571	24.1%	13.8%
AEPSC15	38	\$112,258	\$11,226	\$123,483	\$0	\$123,483	\$128,583	\$2,461	\$131,044	\$1,921	\$132,965	-7.1%	-15.6%
AEPSC16	1	\$ 83,259	\$7,493	\$90,752	\$0	\$ 90,752	\$90,837	\$3,355	\$94,192	\$270	\$94,462	-3.9%	-11.9%
AEPSC17	13	\$165,810	\$33,162	\$198,972	\$7,000	\$ 205,972	\$180,598	\$40,417	\$221,015	\$16,303	\$237,318	-13.2%	-30.1%
AEPSC18	1	\$110,000	\$11,000	\$121,000	\$0	\$121,000	\$128,887	\$10,756	\$139,643	\$1,287	\$140,930	-14.1%	-21.9%
AEPSC19	1	\$137,917	\$20,688	\$158,605	\$0	\$158,605	\$153,564	\$15,375	\$168,939	\$705	\$169,644	-6.5%	-18.7%
AEPSC20	1	\$115,542	\$11,554	\$127,09,09									

		AEP Incumbent Data					Survey Results <sup>1</sup>					% Difference	
Job Identifier <sup>2</sup>	Incumbent Count		Target Short-Term Incentive (STI)	Target Total Cash Compensation (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)	Base	Target STI	Target TCC	Long-Term Incentive (LTI)	Target TC	Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>
		Avg Base											
AEPSC31	3	\$ 148,233	\$29,647	\$177,880	\$7,000	\$ 184,880	\$157,596	\$28,850	\$186,446	\$5,044	\$191,490	-3.5%	-22.6%
AEPSC32	1	\$ 129,500	\$19,425	\$148,925	\$0	\$ 148,925	\$145,357	\$20,727	\$166,084	\$0	\$166,084	-10.3%	-22.0%
AEPSC33	4	\$ 115,862	\$11,586	\$127,448	\$0	\$ 127,448	\$134,083	\$9,779	\$143,862	\$3,916	\$147,778	-13.8%	-21.6%
AEPSC34	1	\$ 98,000	\$8,820	\$106,820	\$0	\$ 106,820	\$97,408	\$2,023	\$99,431	\$87	\$99,518	7.3%	-1.5%
AEPSC35	1	\$ 164,279	\$32,856	\$197,135	\$7,000	\$ 204,135	\$157,492	\$28,347	\$185,839	\$2,509	\$188,348	8.4%	-12.8%
AEPSC36	2	\$ 95,900	\$9,590	\$105,490	\$0	\$ 105,490	\$100,746	\$4,897	\$105,643	\$508	\$106,151	-0.6%	-9.7%
AEPSC37	2	\$ 103,500	\$10,350	\$113,850	\$0	\$ 113,850	\$131,855	\$6,593	\$138,448	\$3,527	\$141,975	-19.8%	-27.1%
AEPSC38	2	\$ 124,985	\$18,748	\$143,733	\$0	\$ 143,733	\$160,089	\$12,891	\$172,980	\$10,422	\$183,402	-21.6%	-31.9%
AEPSC39	1	\$ 193,382	\$48,346	\$241,728	\$25,000	\$ 266,728	\$189,404	\$42,826	\$232,230	\$33,463	\$265,693	0.4%	-27.2%
AEPSC40	10	\$ 125,001	\$12,500	\$137,501	\$0	\$ 137,501	\$128,684	\$14,039	\$142,723	\$0	\$142,723	-3.7%	-12.4%
AEPSC41	1	\$ 212,200	\$53,050	\$265,250	\$25,000	\$ 290,250	\$227,087	\$54,313	\$281,400	\$18,134	\$299,534	-3.1%	-29.2%
AEPSC42	2	\$ 89,597	\$8,064	\$97,660	\$0	\$ 97,660	\$73,682	\$822	\$74,504	\$93	\$74,597	30.9%	20.1%
AEPSC43	4	\$ 123,590	\$12,359	\$135,949	\$0	\$ 135,949	\$138,215	\$19,430	\$157,645	\$0	\$157,645	-13.8%	-21.6%
AEPSC44	4	\$ 113,396	\$11,340	\$124,735	\$0	\$ 124,735	\$142,958	\$6,986	\$149,944	\$4,603	\$154,547	-19.3%	-26.6%
AEPSC45	3	\$ 96,984	\$9,698	\$106,683	\$0	\$ 106,683	\$101,654	\$2,414	\$104,068	\$833	\$104,901	1.7%	-7.5%
AEPSC46	1	\$ 94,578	\$8,512	\$103,090	\$0	\$ 103,090	\$77,807	\$3,373	\$81,180	-\$7	\$81,173	27.0%	16.5%
AEPSC47	1	\$ 89,727	\$8,075	\$97,803	\$0	\$ 97,803	\$91,788	\$5,318	\$97,106	\$0	\$97,106	0.7%	-7.6%
AEPSC48	6	\$ 114,815	\$11,482	\$126,297	\$0	\$ 126,297	\$145,917	\$22,175	\$168,092	\$0	\$168,092	-24.9%	-31.7%
AEPSC49	1	\$ 137,778	\$13,778	\$151,556	\$0	\$ 151,556	\$112,078	\$11,746	\$123,824	\$0	\$123,824	22.4%	11.3%
AEPSC50	4	\$ 98,561	\$9,856	\$108,417	\$0	\$ 108,417	\$114,214	\$12,544	\$126,758	\$0	\$126,758	-14.5%	-22.2%
AEPSC51	1	\$ 103,463	\$10,346	\$113,810	\$0	\$ 113,810	\$96,977	\$8,424	\$105,401	\$268	\$105,669	7.7%	-2.1%
AEPSC52	1	\$ 100,000	\$10,000	\$110,000	\$0	\$ 110,000	\$100,746	\$4,897	\$105,643	\$508	\$106,151	3.6%	-5.8%
AEPSC53	1	\$ 116,461	\$11,646	\$128,107	\$0	\$ 128,107	\$131,855	\$6,593	\$138,448	\$3,527	\$141,975	-9.8%	-18.0%
AEPSC54	3	\$ 142,349	\$21,352	\$163,702	\$0	\$ 163,702	\$160,089	\$12,891	\$172,980	\$10,422	\$183,402	-10.7%	-22.4%
AEPSC55	4	\$ 147,940	\$22,191	\$170,131	\$0	\$ 170,131	\$165,593	\$14,029	\$179,622	\$2,906	\$182,528	-6.8%	-18.9%
AEPSC56	24	\$ 83,877	\$7,549	\$91,426	\$0	\$ 91,426	\$97,338	\$8,265	\$105,603	\$0	\$105,603	-13.4%	-20.6%
AEPSC57	9	\$ 91,460	\$9,146	\$100,606	\$0	\$ 100,606	\$125,974	\$13,735	\$139,709	-\$59	\$139,650	-28.0%	-34.5%
AEPSC58	43	\$ 115,772	\$11,577	\$127,349	\$0	\$ 127,349	\$149,405	\$18,623	\$168,028	\$533	\$168,561	-24.4%	-31.3%
AEPSC59	27	\$ 137,309	\$20,596	\$157,905	\$0	\$ 157,905	\$176,228	\$28,542	\$204,770	\$6,817	\$211,587	-25.4%	-35.1%
AEPSC60	10	\$ 112,281	\$11,228	\$123,509	\$0	\$ 123,509	\$143,429	\$19,692	\$163,121	\$0	\$163,121	-24.3%	-31.2%
AEPSC61	15	\$ 137,479	\$20,622	\$158,101	\$0	\$ 158,101	\$152,250	\$23,073	\$175,323	\$0	\$175,323	-9.8%	-21.6%
AEPSC62	2	\$ 161,246	\$32,249	\$193,495	\$7,000	\$ 200,495	\$168,840	\$23,417	\$192,257	\$4,207	\$196,464	2.1%	-17.9%
AEPSC63	1	\$ 99,545	\$8,959	\$108,504	\$0	\$ 108,504	\$85,336	\$5,284	\$90,620	\$0	\$90,620	19.7%	9.8%
AEPSC64	1	\$ 119,355	\$11,936	\$131,291	\$0	\$ 131,291	\$138,403	\$14,293	\$152,696	\$3,830	\$156,526	-16.1%	-23.7%
AEPSC65	3	\$ 99,081	\$9,908	\$108,990	\$0	\$ 108,990	\$113,642	\$8,162	\$121,804	\$1,042	\$122,846	-11.3%	-19.3%
AEPSC66	1	\$ 101,862	\$10,186	\$112,048	\$0	\$ 112,048	\$108,729	\$8,725	\$117,454	\$1,418	\$118,872	-5.7%	-14.3%
AEPSC67	1	\$ 143,000	\$21,450	\$164,450	\$0	\$ 164,450	\$168,677	\$17,834	\$186,511	\$2,244	\$188,755	-12.9%	-24.2%
AEPSC68	1	\$ 195,025	\$48,756	\$243,782	\$25,000	\$ 268,782	\$198,559	\$42,907	\$241,466	\$17,274	\$258,740	3.9%	-24.6%
AEPSC69	1	\$ 214,812	\$53,703	\$268,515	\$25,000	\$ 293,515	\$198,559	\$42,907	\$241,466	\$17,274	\$258,740	13.4%	-17.0%
AEPSC70	7	\$ 164,476	\$32,895	\$197,372	\$7,000	\$ 204,372	\$165,556	\$27,264	\$192,820	\$4,525	\$197,345	3.6%	-16.7%
AEPSC71	1	\$ 142,810	\$28,562	\$171,372	\$7,000	\$ 178,372	\$167,511	\$28,218	\$195,729	\$4,620	\$200,349	-11.0%	-28.7%
AEPSC72	1	\$ 92,648	\$9,265	\$101,913	\$0	\$ 101,913	\$100,267	\$3,801	\$104,068	\$4,076	\$108,144	-5.8%	-14.3%
AEPSC73	1	\$ 119,710	\$11,971	\$131,681	\$0	\$ 131,681	\$137,994	\$7,129	\$145,123	\$7,413	\$152,536	-13.7%	-21.5%
AEPSC74	1	\$ 63,347	\$3,801	\$67,148	\$0	\$ 67,148	\$72,848	\$4,654	\$77,502	\$0	\$77,502	-13.4%	-18.3%
AEPSC75	2	\$ 72,331	\$5,787	\$78,118	\$0	\$ 78,118	\$79,872	\$4,724	\$84,596	\$305	\$84,901	-8.0%	-14.8%
AEPSC76	1	\$ 85,618	\$7,706	\$93,324	\$0	\$ 93,324	\$104,068	\$6,377	\$110,445	\$281	\$110,726	-15.7%	-22.7%
AEPSC77	1	\$ 165,676	\$33,135	\$198,811	\$7,000	\$ 205,811	\$172,233	\$19,368	\$191,601	\$4,334	\$195,935	5.0%	-15.4%
AEPSC78	1	\$ 115,211	\$11,521	\$126,732	\$0	\$ 126,732	\$142,221	\$13,952	\$156,173	\$0	\$156,173	-18.9%	-26.2%
AEPSC79	1	\$ 163,063	\$32,613	\$195,675	\$7,000	\$ 202,675	\$172,233	\$19,368	\$191,601	\$4,334	\$195,935	3.4%	-16.8%
AEPSC80	1	\$ 96,445	\$9,645	\$106,090	\$0	\$ 106,090	\$95,458	\$485	\$95,943	\$575	\$96,518	9.9%	-0.1%
AEPSC81	1	\$ 63,188	\$5,055	\$68,243	\$0	\$ 68,243	\$75,075	\$2,384	\$77,459	\$0	\$77,459	-11.9%	-18.4%
AEPSC82	1	\$ 93,333	\$9,333	\$102,666	\$0	\$ 102,666	\$98,136	\$1,725	\$99,861	\$86	\$99,947	2.7%	-6.6%
AEPSC83	1	\$ 104,030	\$10,403	\$114,433	\$0	\$ 114,433	\$134,231	\$9,346	\$143,577	\$2,062	\$145,639	-21.4%	-28.6%
AEPSC84	1	\$ 117,735	\$11,773	\$129,508	\$0	\$ 129,508	\$134,143	\$8,670	\$142,813	\$213	\$143,026	-9.5%	-17.7%
AEPSC85	2	\$ 171,350	\$34,270	\$205,620	\$7,000	\$ 212,620	\$187,094	\$37,870	\$224,964	\$20,497	\$245,461	-13.4%	-30.2%
AEPSC86	1	\$ 186,321	\$46,580	\$232,901	\$25,000	\$ 257,901	\$211,692	\$47,732	\$259,424	\$5,046	\$264,470	-2.5%	-29.5%
AEPSC87	1	\$ 115,000	\$17,250	\$132,250	\$0	\$ 132,250	\$135,158	\$14,033	\$149,191	\$1,807	\$150,998	-12.4%	-23.8%
AEPSC88	1	\$ 230,050	\$69,015	\$299,065	\$48,500	\$ 347,565	\$365,413	\$170,600	\$536,013	\$242,435	\$778,448	-55.4%	-70.4%
AEPSC89	1	\$ 231,600	\$81,060	\$312,660	\$93,000	\$ 405,660	\$236,528	\$57,662	\$294,190	\$77,748	\$371,938	9.1%	-37.7%
AEPSC90	1	\$ 197,749	\$49,437	\$247,187	\$25,000	\$ 272,187	\$198,559	\$42,907	\$241,466	\$17,274	\$258,740	5.2%	-23.6%
AEPSC91	2	\$ 275,147	\$96,302	\$371,449	\$93,000	\$ 464,449	\$260,165	\$73,174	\$333,339	\$112,370	\$445,709	4.2%	-38.3%
AEPSC92	1	\$ 122,000	\$12,200	\$134,200	\$0	\$ 134,200	\$98,208	\$5,163	\$103,371	\$253	\$103,624	29.5%	17.7%
AEPSC93	1	\$ 166,340	\$24,951	\$191,291	\$0	\$ 191,291	\$146,955	\$30,279	\$177,234	-\$889	\$176,345	8.5%	-5.7%
AEPSC94	2	\$ 97,099	\$9,710	\$106,809	\$0	\$ 106,809	\$100,746	\$4,897	\$105,643	\$508	\$106,151	0.6%	-8.5%
AEPSC95	1	\$ 125,660	\$12,566	\$138,226	\$0	\$ 138,226	\$131,855	\$6,593	\$138,448	\$3,527	\$141,975	-2.6%	

		AEP Incumbent Data						Survey Results <sup>1</sup>					% Difference	
		Incumbent Count	Target Short-Term Incentive (STI)	Target Total Cash Compensation (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)	Base	Target STI	Target TCC	Long-Term Incentive (LTI)	Target TC	Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>	
Job Identifier <sup>2</sup>		Avg Base												
AEPSC117	1	\$ 210,504	\$52,626	\$263,130	\$25,000	\$ 288,130	\$170,913	\$34,155	\$205,068	\$4,421	\$209,489	37.5%	0.5%	
AEPSC118	1	\$ 214,448	\$53,612	\$268,060	\$25,000	\$ 293,060	\$199,714	\$39,615	\$239,329	\$27,497	\$266,826	9.8%	-19.6%	
AEPSC119	1	\$ 140,098	\$21,015	\$161,113	\$0	\$ 161,113	\$142,250	\$8,171	\$150,421	\$188	\$150,609	7.0%	-7.0%	
AEPSC120	17	\$ 159,619	\$31,924	\$191,543	\$7,000	\$ 198,543	\$176,222	\$16,347	\$192,569	\$3,675	\$196,244	1.2%	-18.7%	
AEPSC121	2	\$ 108,496	\$10,850	\$119,346	\$0	\$ 119,346	\$116,403	\$5,737	\$122,140	\$185	\$122,325	-2.4%	-11.3%	
AEPSC122	1	\$ 157,558	\$23,634	\$181,192	\$0	\$ 181,192	\$172,581	\$16,938	\$189,519	\$1,580	\$191,099	-5.2%	-17.6%	
AEPSC123	1	\$ 132,474	\$13,247	\$145,721	\$0	\$ 145,721	\$142,040	\$9,455	\$151,495	\$756	\$152,251	-4.3%	-13.0%	
AEPSC124	1	\$ 110,936	\$11,094	\$122,030	\$0	\$ 122,030	\$128,887	\$10,756	\$139,643	\$1,287	\$140,930	-13.4%	-21.3%	
AEPSC125	7	\$ 93,453	\$9,345	\$102,799	\$0	\$ 102,799	\$121,311	\$13,010	\$134,321	\$262	\$134,583	-23.6%	-30.6%	
AEPSC126	4	\$ 69,943	\$5,595	\$75,538	\$0	\$ 75,538	\$81,887	\$5,266	\$87,153	\$60	\$87,213	-13.4%	-19.8%	
AEPSC127	8	\$ 83,851	\$7,547	\$91,398	\$0	\$ 91,398	\$101,557	\$9,962	\$111,519	-\$1,029	\$110,490	-17.3%	-24.1%	
AEPSC128	7	\$ 123,756	\$12,376	\$136,132	\$0	\$ 136,132	\$126,734	\$13,042	\$139,776	-\$2,146	\$137,630	-1.1%	-10.1%	
AEPSC129	3	\$ 93,367	\$9,337	\$102,703	\$0	\$ 102,703	\$102,819	\$3,331	\$106,150	\$0	\$106,150	-3.2%	-12.0%	
AEPSC130	6	\$ 98,249	\$9,825	\$108,074	\$0	\$ 108,074	\$105,642	\$8,833	\$114,475	\$2,760	\$117,235	-7.8%	-16.2%	
AEPSC131	4	\$ 209,075	\$52,269	\$261,344	\$25,000	\$ 286,344	\$168,453	\$14,617	\$183,070	\$2,895	\$185,965	54.0%	12.4%	
AEPSC132	9	\$ 121,844	\$18,277	\$140,121	\$0	\$ 140,121	\$135,289	\$14,102	\$149,391	\$103	\$149,494	-6.3%	-18.5%	
AEPSC133	5	\$ 82,300	\$7,407	\$89,707	\$0	\$ 89,707	\$78,051	\$1,820	\$79,871	\$22	\$79,893	12.3%	3.0%	
AEPSC134	1	\$ 104,124	\$10,412	\$114,536	\$0	\$ 114,536	\$131,475	\$11,436	\$142,911	\$2,262	\$145,173	-21.1%	-28.3%	
AEPSC135	9	\$ 96,089	\$9,609	\$105,698	\$0	\$ 105,698	\$102,193	\$3,929	\$106,122	-\$54	\$106,068	-0.3%	-9.4%	
AEPSC136	1	\$ 165,000	\$33,000	\$198,000	\$7,000	\$ 205,000	\$155,148	\$19,480	\$174,628	\$4,674	\$179,302	14.3%	-8.0%	
AEPSC137	8	\$ 112,219	\$11,222	\$123,441	\$0	\$ 123,441	\$130,633	\$6,221	\$136,854	\$938	\$137,792	-10.4%	-18.6%	
AEPSC138	4	\$ 96,852	\$9,685	\$106,537	\$0	\$ 106,537	\$106,150	\$3,967	\$110,117	\$0	\$110,117	-3.3%	-12.0%	
AEPSC139	1	\$ 87,300	\$6,984	\$94,284	\$0	\$ 94,284	\$84,606	\$2,420	\$87,026	\$0	\$87,026	8.3%	0.3%	
AEPSC140	7	\$ 129,229	\$19,384	\$148,613	\$0	\$ 148,613	\$143,397	\$14,429	\$157,826	\$2,423	\$160,249	-7.3%	-19.4%	
AEPSC141	1	\$ 231,634	\$69,490	\$301,124	\$48,500	\$ 349,624	\$174,109	\$19,458	\$193,567	\$0	\$193,567	80.6%	19.7%	
AEPSC142	1	\$ 130,566	\$19,585	\$150,151	\$0	\$ 150,151	\$144,601	\$23,343	\$167,944	\$1,067	\$169,011	-11.2%	-22.7%	
AEPSC143	2	\$ 88,185	\$7,937	\$96,121	\$0	\$ 96,121	\$83,255	\$5,649	\$88,904	\$89	\$88,993	8.0%	-0.9%	
AEPSC144	1	\$ 133,900	\$20,085	\$153,985	\$0	\$ 153,985	\$155,308	\$10,983	\$166,291	\$0	\$166,291	-7.4%	-19.5%	
AEPSC145	1	\$ 81,679	\$7,351	\$89,030	\$0	\$ 89,030	\$88,203	\$7,540	\$95,743	\$0	\$95,743	-7.0%	-14.7%	
AEPSC146	1	\$ 89,895	\$8,091	\$97,985	\$0	\$ 97,985	\$88,203	\$7,540	\$95,743	\$0	\$95,743	2.3%	-6.1%	
AEPSC147	1	\$ 81,093	\$7,298	\$88,391	\$0	\$ 88,391	\$111,867	\$8,642	\$120,509	\$1,563	\$122,072	-27.6%	-33.6%	
AEPSC148	4	\$ 69,614	\$5,569	\$75,183	\$0	\$ 75,183	\$76,979	\$1,056	\$78,035	-\$130	\$77,905	-3.5%	-10.6%	
AEPSC149	3	\$ 71,878	\$5,750	\$77,628	\$0	\$ 77,628	\$101,570	\$6,953	\$108,523	\$0	\$108,523	-28.5%	-33.8%	
AEPSC150	2	\$ 205,500	\$51,375	\$256,875	\$25,000	\$ 281,875	\$190,081	\$37,045	\$227,126	\$15,043	\$242,169	16.4%	-15.1%	
AEPSC151	4	\$ 119,625	\$11,963	\$131,588	\$0	\$ 131,588	\$129,859	\$6,056	\$135,915	\$0	\$135,915	-3.2%	-12.0%	
AEPSC152	1	\$ 159,215	\$31,843	\$191,057	\$7,000	\$ 198,057	\$181,293	\$14,343	\$195,636	\$13,720	\$209,356	-5.4%	-24.0%	
AEPSC153	1	\$ 180,000	\$45,000	\$225,000	\$25,000	\$ 250,000	\$192,031	\$32,756	\$224,787	\$20,202	\$244,989	2.0%	-26.5%	
AEPSC154	1	\$ 74,087	\$5,927	\$80,014	\$0	\$ 80,014	\$81,390	\$4,214	\$85,604	\$1,566	\$87,170	-8.2%	-15.0%	
AEPSC155	2	\$ 156,475	\$31,295	\$187,770	\$7,000	\$ 194,770	\$171,150	\$26,134	\$197,284	\$5,709	\$202,993	-4.1%	-22.9%	
AEPSC156	2	\$ 168,434	\$33,687	\$202,120	\$7,000	\$ 209,120	\$192,245	\$23,787	\$216,032	\$3,815	\$219,847	-4.9%	-23.4%	
AEPSC157	1	\$ 158,069	\$31,614	\$189,683	\$7,000	\$ 196,683	\$192,245	\$23,787	\$216,032	\$3,815	\$219,847	-10.5%	-28.1%	
AEPSC158	14	\$ 162,735	\$32,547	\$195,283	\$7,000	\$ 202,283	\$166,008	\$26,935	\$192,943	\$4,044	\$196,987	2.7%	-17.4%	
AEPSC159	1	\$ 203,695	\$50,924	\$254,619	\$25,000	\$ 279,619	\$178,542	\$27,506	\$206,048	\$5,770	\$211,818	32.0%	-3.8%	
AEPSC160	8	\$ 213,116	\$63,935	\$277,051	\$48,500	\$ 325,551	\$229,947	\$65,298	\$295,245	\$67,858	\$363,103	-10.3%	-41.3%	
AEPSC161	1	\$ 176,000	\$44,000	\$220,000	\$25,000	\$ 245,000	\$176,937	\$28,772	\$205,709	\$10,688	\$216,397	13.2%	-18.7%	
AEPSC162	1	\$ 115,000	\$11,500	\$126,500	\$0	\$ 126,500	\$142,040	\$9,455	\$151,495	\$756	\$152,251	-16.9%	-24.5%	
AEPSC163	3	\$ 70,896	\$5,672	\$76,568	\$0	\$ 76,568	\$78,051	\$853	\$78,904	\$157	\$79,061	-3.2%	-10.3%	
AEPSC164	1	\$ 129,394	\$19,409	\$148,803	\$0	\$ 148,803	\$135,449	\$17,415	\$152,864	\$0	\$152,864	-2.7%	-15.4%	
AEPSC165	1	\$ 73,112	\$4,387	\$77,499	\$0	\$ 77,499	\$64,522	\$949	\$65,471	\$0	\$65,471	18.4%	11.7%	
AEPSC166	1	\$ 95,062	\$9,506	\$104,569	\$0	\$ 104,569	\$96,858	\$2,123	\$98,981	\$439	\$99,420	5.2%	-4.4%	
AEPSC167	1	\$ 226,275	\$67,883	\$294,158	\$48,500	\$ 342,658	\$235,371	\$62,797	\$298,168	\$43,713	\$341,881	0.2%	-33.8%	
AEPSC168	1	\$ 112,500	\$11,250	\$123,750	\$0	\$ 123,750	\$107,192	\$5,202	\$112,394	\$2,808	\$115,202	7.4%	-2.3%	
AEPSC169	1	\$ 174,575	\$43,644	\$218,219	\$25,000	\$ 243,219	\$190,081	\$37,045	\$227,126	\$15,043	\$242,169	0.4%	-27.9%	
AEPSC170	1	\$ 67,000	\$5,360	\$72,360	\$0	\$ 72,360	\$94,698	\$9,029	\$103,727	\$1,805	\$105,532	-31.4%	-36.5%	
AEPSC171	2	\$ 78,500	\$7,065	\$85,565	\$0	\$ 85,565	\$82,630	\$1,145	\$83,775	\$0	\$83,775	2.1%	-6.3%	
AEPSC172	1	\$ 175,000	\$43,750	\$218,750	\$25,000	\$ 243,750	\$190,081	\$37,045	\$227,126	\$15,043	\$242,169	0.7%	-27.7%	
AEPSC173	12	\$ 113,879	\$11,388	\$125,267	\$0	\$ 125,267	\$130,501	\$9,296	\$139,797	\$691	\$140,488	-10.8%	-18.9%	
AEPSC174	1	\$ 65,676	\$3,941	\$69,617	\$0	\$ 69,617	\$69,408	\$1,358	\$70,766	\$237	\$71,003	-2.0%	-7.5%	
AEPSC175	10	\$ 98,980	\$9,898	\$108,878	\$0	\$ 108,878	\$103,527	\$5,242	\$108,769	\$340	\$109,109	-0.2%	-9.3%	
AEPSC176	3	\$ 114,077	\$11,408	\$125,485	\$0	\$ 125,485	\$146,729	\$19,655	\$166,384	-\$201	\$166,183	-24.5%	-31.4%	
AEPSC177	1	\$ 82,647	\$7,438	\$90,086	\$0	\$ 90,086	\$87,161	\$999	\$88,160	\$0	\$88,160	2.2%	-6.3%	
AEPSC178	1	\$ 123,600	\$18,540	\$142,140	\$0	\$ 142,140	\$139,383	\$13,363	\$152,746	\$1,927	\$154,673	-8.1%	-20.1%	
AEPSC179	5	\$ 139,684	\$20,953	\$160,637	\$0	\$ 160,637	\$163,283	\$14,473	\$177,756	\$595	\$178,351	-9.9%	-21.7%	
AEPSC180	1	\$ 124,606	\$12,461	\$137,067	\$0	\$ 137,067	\$131,714	\$12,568	\$144,282	\$0	\$144,282	-5.0%	-13.6%	
AEPSC181	4	\$ 81,639	\$6,531	\$88,170	\$0	\$ 88,170	\$70,766	\$3,937	\$74,703	\$0	\$74,703	18.0%	9.3%	



		AEP Incumbent Data					Survey Results <sup>1</sup>					% Difference	
			Target Short-Term Incentive (STI)	Target Total Cash Compensation (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)				Long-Term Incentive (LTI)		Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>
Job Identifier <sup>2</sup>	Incumbent Count	Avg Base					Base	Target STI	Target TCC		Target TC		
AEPSC203	1	\$ 124,990	\$18,749	\$143,739	\$0	\$ 143,739	\$137,865	\$9,989	\$147,854	\$237	\$148,091	-2.9%	-15.6%
AEPSC204	1	\$ 96,819	\$9,682	\$106,500	\$0	\$ 106,500	\$116,403	\$5,737	\$122,140	\$185	\$122,325	-12.9%	-20.9%
AEPSC205	1	\$ 207,000	\$51,750	\$258,750	\$25,000	\$ 283,750	\$205,183	\$43,748	\$248,931	\$22,955	\$271,886	4.4%	-23.9%
AEPSC206	3	\$ 136,589	\$20,488	\$157,077	\$0	\$ 157,077	\$148,099	\$4,050	\$152,149	\$0	\$152,149	3.2%	-10.2%
AEPSC207	3	\$ 111,508	\$11,151	\$122,659	\$0	\$ 122,659	\$139,804	\$3,432	\$143,236	\$0	\$143,236	-14.4%	-22.2%
AEPSC208	2	\$ 87,745	\$7,897	\$95,642	\$0	\$ 95,642	\$91,788	\$5,318	\$97,106	\$0	\$97,106	-1.5%	-9.6%
AEPSC209	1	\$ 92,623	\$9,262	\$101,886	\$0	\$ 101,886	\$111,873	\$4,267	\$116,140	\$174	\$116,314	-12.4%	-20.4%
AEPSC210	1	\$ 196,231	\$49,058	\$245,288	\$25,000	\$ 270,288	\$197,729	\$33,367	\$231,096	\$41,771	\$272,867	-0.9%	-28.1%
AEPSC211	1	\$ 239,437	\$71,831	\$311,269	\$48,500	\$ 359,769	\$255,662	\$82,559	\$338,221	\$72,099	\$410,320	-12.3%	-41.6%
AEPSC212	6	\$ 100,326	\$10,033	\$110,358	\$0	\$ 110,358	\$91,788	\$577	\$92,365	\$0	\$92,365	19.5%	8.6%
AEPSC213	9	\$ 115,467	\$11,547	\$127,014	\$0	\$ 127,014	\$134,638	\$4,709	\$139,347	\$0	\$139,347	-8.9%	-17.1%
AEPSC214	1	\$ 94,700	\$9,470	\$104,170	\$0	\$ 104,170	\$106,816	\$5,042	\$111,858	\$5,739	\$117,597	-11.4%	-19.5%
AEPSC215	1	\$ 190,550	\$47,638	\$238,188	\$25,000	\$ 263,188	\$195,795	\$46,392	\$242,187	\$19,653	\$261,840	0.5%	-27.2%
AEPSC216	2	\$ 95,172	\$9,517	\$104,689	\$0	\$ 104,689	\$109,452	\$11,710	\$121,162	\$0	\$121,162	-13.6%	-21.5%
AEPSC217	1	\$ 79,000	\$7,110	\$86,110	\$0	\$ 86,110	\$84,782	\$10,461	\$95,243	\$449	\$95,692	-10.0%	-17.4%
AEPSC218	2	\$ 88,406	\$7,957	\$96,363	\$0	\$ 96,363	\$80,690	\$5,822	\$86,512	\$0	\$86,512	11.4%	2.2%
AEPSC219	1	\$ 228,655	\$68,596	\$297,251	\$48,500	\$ 345,751	\$278,096	\$134,064	\$412,160	\$70,762	\$482,922	-28.4%	-52.7%
AEPSC220	1	\$ 227,497	\$68,249	\$295,746	\$48,500	\$ 344,246	\$239,357	\$61,291	\$300,648	\$62,532	\$363,180	-5.2%	-37.4%
AEPSC221	2	\$ 116,563	\$11,656	\$128,219	\$0	\$ 128,219	\$113,264	\$10,301	\$123,565	\$0	\$123,565	3.8%	-5.7%
AEPSC222	63	\$ 168,888	\$33,778	\$202,666	\$7,000	\$ 209,666	\$189,369	\$25,294	\$214,663	\$12,108	\$226,771	-7.5%	-25.5%
AEPSC223	1	\$ 146,033	\$21,905	\$167,938	\$0	\$ 167,938	\$158,044	\$14,886	\$172,930	\$996	\$173,926	-3.4%	-16.0%
AEPSC224	21	\$ 137,433	\$20,615	\$158,048	\$0	\$ 158,048	\$160,792	\$12,269	\$173,061	\$1,303	\$174,364	-9.4%	-21.2%
AEPSC225	1	\$ 137,917	\$13,792	\$151,709	\$0	\$ 151,709	\$147,662	\$16,176	\$163,838	\$960	\$164,798	-7.9%	-16.3%
AEPSC226	1	\$ 122,457	\$12,246	\$134,703	\$0	\$ 134,703	\$128,418	\$14,269	\$142,687	\$0	\$142,687	-5.6%	-14.2%
AEPSC227	3	\$ 164,139	\$32,828	\$196,967	\$7,000	\$ 203,967	\$188,676	\$23,792	\$212,468	\$10,226	\$222,694	-8.4%	-26.3%
AEPSC228	1	\$ 128,763	\$12,876	\$141,639	\$0	\$ 141,639	\$144,359	\$3,245	\$147,604	\$264	\$147,868	-4.2%	-12.9%
AEPSC229	1	\$ 249,600	\$74,880	\$324,480	\$48,500	\$ 372,980	\$235,371	\$62,797	\$298,168	\$43,713	\$341,881	9.1%	-27.0%
AEPSC230	1	\$ 130,489	\$19,573	\$150,062	\$0	\$ 150,062	\$148,099	\$4,050	\$152,149	\$0	\$152,149	-1.4%	-14.2%
AEPSC231	6	\$ 98,958	\$9,896	\$108,854	\$0	\$ 108,854	\$107,705	\$11,344	\$119,049	-\$363	\$118,686	-8.3%	-16.6%
AEPSC232	10	\$ 81,225	\$7,310	\$88,536	\$0	\$ 88,536	\$84,817	\$6,268	\$91,085	-\$46	\$91,039	-2.7%	-10.8%
AEPSC233	1	\$ 158,614	\$23,792	\$182,406	\$0	\$ 182,406	\$155,263	\$3,996	\$159,259	\$3,721	\$162,980	11.9%	-2.7%
AEPSC234	1	\$ 86,931	\$7,824	\$94,755	\$0	\$ 94,755	\$94,416	\$3,643	\$98,059	\$616	\$98,675	-4.0%	-11.9%
AEPSC235	1	\$ 395,869	\$178,141	\$574,010	\$266,500	\$ 840,510	\$364,227	\$123,215	\$487,442	\$204,193	\$691,635	21.5%	-42.8%
AEPSC236	2	\$ 124,945	\$18,742	\$143,687	\$0	\$ 143,687	\$140,236	\$21,005	\$161,241	-\$3,089	\$158,152	-9.1%	-21.0%
AEPSC237	5	\$ 234,078	\$70,223	\$304,301	\$48,500	\$ 352,801	\$245,002	\$62,431	\$307,433	\$48,789	\$356,222	-1.0%	-34.3%
AEPSC238	2	\$ 159,118	\$31,824	\$190,941	\$7,000	\$ 197,941	\$169,180	\$40,283	\$209,463	\$2,961	\$212,424	-6.8%	-25.1%
AEPSC239	1	\$ 108,500	\$10,850	\$119,350	\$0	\$ 119,350	\$69,738	\$1,997	\$71,735	\$0	\$71,735	66.4%	51.3%
AEPSC240	20	\$ 198,769	\$49,692	\$248,461	\$25,000	\$ 273,461	\$197,620	\$36,487	\$234,107	\$3,575	\$237,682	15.1%	-16.4%
AEPSC241	2	\$ 263,696	\$79,109	\$342,804	\$48,500	\$ 391,304	\$202,933	\$13,112	\$216,045	\$0	\$216,045	81.1%	22.1%
AEPSC242	2	\$ 92,534	\$8,328	\$100,862	\$0	\$ 100,862	\$80,028	\$4,918	\$84,946	\$6	\$84,952	18.7%	8.9%
AEPSC243	2	\$ 86,415	\$7,777	\$94,192	\$0	\$ 94,192	\$78,292	\$2,075	\$80,367	\$0	\$80,367	17.2%	7.5%
AEPSC244	2	\$ 96,312	\$9,631	\$105,943	\$0	\$ 105,943	\$105,707	\$6,778	\$112,485	\$74	\$112,559	-5.9%	-14.4%
AEPSC245	1	\$ 190,550	\$47,638	\$238,188	\$25,000	\$ 263,188	\$184,666	\$28,279	\$212,945	\$8,674	\$221,619	18.8%	-14.0%
AEPSC246	1	\$ 175,600	\$35,120	\$210,720	\$7,000	\$ 217,720	\$173,307	\$24,707	\$198,014	\$4,829	\$202,843	7.3%	-13.4%
AEPSC247	17	\$ 78,993	\$7,109	\$86,103	\$0	\$ 86,103	\$72,848	\$4,415	\$77,263	-\$13	\$77,250	11.5%	2.3%
AEPSC248	1	\$ 158,050	\$23,708	\$181,758	\$0	\$ 181,758	\$149,599	\$13,616	\$163,215	\$423	\$163,638	11.1%	-3.4%
AEPSC249	4	\$ 107,475	\$10,747	\$118,222	\$0	\$ 118,222	\$116,403	\$5,737	\$122,140	\$185	\$122,325	-3.4%	-12.1%
AEPSC250	9	\$ 101,112	\$10,111	\$111,223	\$0	\$ 111,223	\$100,604	\$11,454	\$112,058	\$732	\$112,790	-1.4%	-10.4%
AEPSC251	1	\$ 190,962	\$47,741	\$238,703	\$25,000	\$ 263,703	\$204,240	\$57,925	\$262,165	\$39,001	\$301,166	-12.4%	-36.6%
AEPSC252	1	\$ 105,598	\$10,560	\$116,158	\$0	\$ 116,158	\$125,714	\$3,461	\$129,175	\$465	\$129,640	-10.4%	-18.5%
AEPSC253	1	\$ 66,641	\$5,331	\$71,972	\$0	\$ 71,972	\$70,496	\$4,402	\$74,898	\$432	\$75,330	-4.5%	-11.5%
AEPSC254	2	\$ 93,044	\$9,304	\$102,348	\$0	\$ 102,348	\$80,913	\$6,628	\$87,541	\$308	\$87,849	16.5%	5.9%
AEPSC255	1	\$ 78,365	\$7,053	\$85,418	\$0	\$ 85,418	\$92,881	\$8,257	\$101,138	\$0	\$101,138	-15.5%	-22.5%
AEPSC256	1	\$ 125,742	\$12,574	\$138,316	\$0	\$ 138,316	\$142,221	\$13,952	\$156,173	\$0	\$156,173	-11.4%	-19.5%
AEPSC257	3	\$ 60,826	\$3,650	\$64,475	\$0	\$ 64,475	\$62,006	\$841	\$62,847	\$793	\$63,640	1.3%	-4.4%
AEPSC258	5	\$ 69,443	\$5,555	\$74,998	\$0	\$ 74,998	\$78,051	-\$473	\$77,578	\$372	\$77,950	-3.8%	-10.9%
AEPSC259	1	\$ 81,969	\$7,377	\$89,346	\$0	\$ 89,346	\$83,575	\$5,317	\$88,892	\$1,126	\$90,018	-0.7%	-8.9%
AEPSC260	1	\$ 101,383	\$10,138	\$111,521	\$0	\$ 111,521	\$118,541	\$14,751	\$133,292	\$1,791	\$135,083	-17.4%	-24.9%
AEPSC261	1	\$ 133,638	\$20,046	\$153,684	\$0	\$ 153,684	\$145,857	\$25,426	\$171,283	\$228	\$171,511	-10.4%	-22.1%
AEPSC262	5	\$ 140,220	\$28,044	\$168,264	\$7,000	\$ 175,264	\$140,481	\$18,352	\$158,833	\$0	\$158,833	10.3%	-11.7%
AEPSC263	3	\$ 96,883	\$9,688	\$106,572	\$0	\$ 106,572	\$103,710	\$9,443	\$113,153	\$0	\$113,153	-5.8%	-14.4%
AEPSC264	3	\$ 137,159	\$20,574	\$157,733	\$0	\$ 157,733	\$149,599	\$13,616	\$163,215	\$423	\$163,638	-3.6%	-16.2%
AEPSC265	3	\$ 87,074	\$7,837	\$94,911	\$0	\$ 94,911	\$95,353	\$3,617	\$98,970	\$124	\$99,094	-4.2%	-12.1%
AEPSC266	3	\$ 113,200	\$11,320	\$124,520	\$0	\$ 124,520	\$144,455	\$20,991	\$165,446	\$842	\$166,288	-25.1%	-31.9%
AEPSC267	1	\$ 74,184	\$5,935	\$80,119	\$0	\$ 80,119	\$78,051	-\$473	\$77,578	\$372	\$77,950	2.8%	-4.8%</



Job Identifier <sup>2</sup>	Incumbent Count	AEP Incumbent Data						Survey Results <sup>1</sup>					% Difference	
		Avg Base	Target Short-Term Incentive (STI)	Target Total Cash Compensation (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)		Base	Target STI	Target TCC	Long-Term Incentive (LTI)	Target TC	Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>
AEPSC289	1	\$ 248,188	\$62,047	\$310,235	\$25,000	\$ 335,235		\$198,559	\$42,907	\$241,466	\$17,274	\$258,740	29.6%	-4.1%
AEPSC290	4	\$ 200,966	\$60,290	\$261,255	\$48,500	\$ 309,755		\$236,609	\$48,301	\$284,910	\$12,220	\$297,130	4.2%	-32.4%
AEPSC291	1	\$ 265,200	\$79,560	\$344,760	\$48,500	\$ 393,260		\$244,512	\$64,254	\$308,766	\$60,603	\$369,369	6.5%	-28.2%
AEPSC292	2	\$ 116,822	\$11,682	\$128,504	\$0	\$ 128,504		\$116,403	\$5,737	\$122,140	\$185	\$122,325	5.1%	-4.5%
AEPSC293	4	\$ 158,945	\$31,789	\$190,734	\$7,000	\$ 197,734		\$169,624	\$17,816	\$187,440	\$8,032	\$195,472	1.2%	-18.7%
AEPSC294	2	\$ 105,603	\$10,560	\$116,163	\$0	\$ 116,163		\$103,360	\$4,454	\$107,814	\$6,661	\$114,475	1.5%	-7.8%
AEPSC295	1	\$ 177,500	\$35,500	\$213,000	\$7,000	\$ 220,000		\$187,362	\$43,710	\$231,072	\$19,746	\$250,818	-12.3%	-29.2%
AEPSC296	1	\$ 162,875	\$32,575	\$195,450	\$7,000	\$ 202,450		\$196,730	\$40,634	\$237,364	\$6,508	\$243,872	-17.0%	-33.2%
AEPSC297	1	\$ 117,981	\$11,798	\$129,779	\$0	\$ 129,779		\$107,192	\$5,202	\$112,394	\$2,808	\$115,202	12.7%	2.4%
AEPSC298	26	\$ 97,738	\$9,774	\$107,511	\$0	\$ 107,511		\$104,516	\$10,633	\$115,149	\$3,773	\$118,922	-9.6%	-17.8%
AEPSC299	13	\$ 140,549	\$21,082	\$161,631	\$0	\$ 161,631		\$156,610	\$18,489	\$175,099	-\$811	\$174,288	-7.3%	-19.4%
AEPSC300	17	\$ 114,611	\$11,461	\$126,072	\$0	\$ 126,072		\$124,778	\$13,221	\$137,999	\$826	\$138,825	-9.2%	-17.4%
AEPSC301	2	\$ 78,087	\$6,247	\$84,334	\$0	\$ 84,334		\$82,068	\$1,187	\$83,255	\$0	\$83,255	1.3%	-6.2%
AEPSC302	1	\$ 156,094	\$31,219	\$187,313	\$7,000	\$ 194,313		\$180,953	\$30,551	\$211,504	\$2,745	\$214,249	-9.3%	-27.1%
AEPSC303	1	\$ 150,000	\$30,000	\$180,000	\$7,000	\$ 187,000		\$170,812	\$32,203	\$203,015	-\$4,576	\$198,439	-5.8%	-24.4%
AEPSC304	2	\$ 112,337	\$11,234	\$123,571	\$0	\$ 123,571		\$95,604	\$9,102	\$104,706	\$1,946	\$106,652	15.9%	5.3%
AEPSC305	6	\$ 139,650	\$20,948	\$160,598	\$0	\$ 160,598		\$140,841	\$17,055	\$157,896	\$3,448	\$161,344	-0.5%	-13.4%
AEPSC306	1	\$ 142,651	\$21,398	\$164,048	\$0	\$ 164,048		\$139,866	\$14,328	\$154,194	\$0	\$154,194	6.4%	-7.5%
AEPSC307	1	\$ 105,808	\$10,581	\$116,389	\$0	\$ 116,389		\$117,378	\$13,312	\$130,690	\$515	\$131,205	-11.3%	-19.4%
AEPSC308	1	\$ 160,680	\$32,136	\$192,816	\$7,000	\$ 199,816		\$168,580	\$23,103	\$191,683	\$1,856	\$193,539	3.2%	-17.0%
AEPSC309	1	\$ 65,115	\$3,907	\$69,022	\$0	\$ 69,022		\$66,806	\$4,810	\$71,616	\$0	\$71,616	-3.6%	-9.1%
AEPSC310	4	\$ 110,094	\$11,009	\$121,104	\$0	\$ 121,104		\$129,044	\$7,551	\$136,595	\$486	\$137,081	-11.7%	-19.7%
AEPSC311	5	\$ 95,150	\$9,515	\$104,665	\$0	\$ 104,665		\$100,483	\$4,988	\$105,471	\$713	\$106,184	-1.4%	-10.4%
AEPSC312	1	\$ 158,482	\$23,772	\$182,254	\$0	\$ 182,254		\$163,179	\$15,686	\$178,865	\$7,776	\$186,641	-2.4%	-15.1%
AEPSC313	2	\$ 108,920	\$10,892	\$119,812	\$0	\$ 119,812		\$129,044	\$7,551	\$136,595	\$486	\$137,081	-12.6%	-20.5%
AEPSC314	1	\$ 108,150	\$10,815	\$118,965	\$0	\$ 118,965		\$124,888	\$14,776	\$139,664	\$1,213	\$140,877	-15.6%	-23.2%
AEPSC315	2	\$ 76,884	\$6,920	\$83,804	\$0	\$ 83,804		\$95,243	\$5,087	\$100,330	\$100	\$100,430	-16.6%	-23.4%
AEPSC316	27	\$ 143,237	\$21,486	\$164,723	\$0	\$ 164,723		\$146,228	\$21,398	\$167,626	\$35	\$167,661	-1.8%	-14.6%
AEPSC317	1	\$ 142,446	\$14,245	\$156,691	\$0	\$ 156,691		\$131,201	\$16,721	\$147,922	\$0	\$147,922	5.9%	-3.7%
AEPSC318	15	\$ 103,261	\$10,326	\$113,587	\$0	\$ 113,587		\$117,059	\$8,077	\$125,136	\$0	\$125,136	-9.2%	-17.5%
AEPSC319	17	\$ 89,213	\$8,921	\$97,242	\$0	\$ 97,242		\$95,530	\$9,547	\$105,077	\$0	\$105,077	-7.5%	-15.1%
AEPSC320	27	\$ 135,726	\$20,359	\$156,085	\$0	\$ 156,085		\$146,228	\$21,398	\$167,626	\$35	\$167,661	-6.9%	-19.0%
AEPSC321	31	\$ 121,822	\$12,182	\$134,005	\$0	\$ 134,005		\$131,201	\$16,721	\$147,922	\$0	\$147,922	-9.4%	-17.6%
AEPSC322	9	\$ 183,464	\$45,866	\$229,330	\$25,000	\$ 254,330		\$194,159	\$41,040	\$235,199	\$25,923	\$261,122	-2.6%	-29.7%
AEPSC323	1	\$ 148,954	\$29,791	\$178,745	\$7,000	\$ 185,745		\$178,793	\$24,027	\$202,820	\$3,698	\$206,518	-10.1%	-27.9%
AEPSC324	3	\$ 179,179	\$35,836	\$215,015	\$7,000	\$ 222,015		\$154,326	\$14,448	\$168,774	\$420	\$169,194	31.2%	5.9%
AEPSC325	1	\$ 101,000	\$10,100	\$111,100	\$0	\$ 111,100		\$107,158	\$9,698	\$116,856	\$2,611	\$119,467	-7.0%	-15.5%
AEPSC326	5	\$ 141,637	\$21,246	\$162,883	\$0	\$ 162,883		\$148,099	\$4,050	\$152,149	\$0	\$152,149	7.1%	-6.9%
AEPSC327	1	\$ 119,025	\$11,903	\$130,928	\$0	\$ 130,928		\$113,901	\$9,441	\$123,342	\$0	\$123,342	6.1%	-3.5%
AEPSC328	3	\$ 126,337	\$12,634	\$138,971	\$0	\$ 138,971		\$124,081	\$8,632	\$132,713	\$0	\$132,713	4.7%	-4.8%
AEPSC329	2	\$ 112,000	\$11,200	\$123,200	\$0	\$ 123,200		\$107,062	\$6,286	\$113,348	\$0	\$113,348	8.7%	-1.2%
AEPSC330	21	\$ 120,731	\$12,073	\$132,804	\$0	\$ 132,804		\$124,081	\$8,632	\$132,713	\$0	\$132,713	0.1%	-9.0%
AEPSC331	3	\$ 91,036	\$9,104	\$100,139	\$0	\$ 100,139		\$109,038	-\$2,384	\$106,654	\$0	\$106,654	-6.1%	-14.6%
AEPSC332	1	\$ 160,000	\$32,000	\$192,000	\$7,000	\$ 199,000		\$148,750	\$7,968	\$156,718	\$0	\$156,718	27.0%	2.1%
AEPSC333	1	\$ 123,481	\$12,348	\$135,829	\$0	\$ 135,829		\$115,459	\$9,423	\$124,882	\$152	\$125,034	8.6%	-1.2%
AEPSC334	5	\$ 153,725	\$30,745	\$184,470	\$7,000	\$ 191,470		\$172,703	\$38,069	\$210,772	\$4,134	\$214,906	-10.9%	-28.5%
AEPSC335	1	\$ 94,500	\$9,450	\$103,950	\$0	\$ 103,950		\$120,615	\$11,729	\$132,344	-\$1,967	\$130,377	-20.3%	-27.5%
AEPSC336	19	\$ 79,666	\$7,170	\$86,836	\$0	\$ 86,836		\$90,837	\$3,355	\$94,192	\$270	\$94,462	-8.1%	-15.7%
AEPSC337	4	\$ 68,664	\$5,493	\$74,157	\$0	\$ 74,157		\$74,305	\$2,388	\$76,693	\$118	\$76,811	-3.5%	-10.6%
AEPSC338	9	\$ 98,138	\$9,814	\$107,952	\$0	\$ 107,952		\$116,403	\$5,737	\$122,140	\$185	\$122,325	-11.8%	-19.8%
AEPSC339	4	\$ 139,208	\$20,881	\$160,089	\$0	\$ 160,089		\$172,581	\$16,938	\$189,519	\$1,580	\$191,099	-16.2%	-27.2%
AEPSC340	14	\$ 123,283	\$12,328	\$135,611	\$0	\$ 135,611		\$142,040	\$9,455	\$151,495	\$756	\$152,251	-10.9%	-19.0%
AEPSC341	6	\$ 99,366	\$9,937	\$109,303	\$0	\$ 109,303		\$116,403	\$5,737	\$122,140	\$185	\$122,325	-10.6%	-18.8%
AEPSC342	1	\$ 101,410	\$10,141	\$111,551	\$0	\$ 111,551		\$116,252	\$10,315	\$126,567	-\$322	\$126,245	-11.6%	-19.7%
AEPSC343	1	\$ 86,217	\$7,760	\$93,976	\$0	\$ 93,976		\$96,858	\$2,123	\$98,981	\$439	\$99,420	-5.5%	-13.3%
AEPSC344	1	\$ 105,060	\$10,506	\$115,566	\$0	\$ 115,566		\$95,243	\$5,087	\$100,330	\$100	\$100,430	15.1%	4.6%
AEPSC345	2	\$ 70,123	\$5,610	\$75,733	\$0	\$ 75,733		\$75,796	\$2,237	\$78,033	\$24	\$78,057	-3.0%	-10.2%
AEPSC346	1	\$ 174,820	\$34,964	\$209,784	\$7,000	\$ 216,784		\$179,547	\$27,843	\$207,390	\$6,560	\$213,950	1.3%	-18.3%
AEPSC347	1	\$ 74,380	\$6,694	\$81,074	\$0	\$ 81,074		\$86,123	\$1,044	\$87,167	\$106	\$87,273	-7.1%	-14.8%
AEPSC348	1	\$ 108,469	\$10,847	\$119,316	\$0	\$ 119,316		\$111,041	\$4,150	\$115,191	\$328	\$115,519	3.3%	-6.1%
AEPSC349	1	\$ 135,783	\$13,578	\$149,361	\$0	\$ 149,361		\$134,028	\$12,213	\$146,241	\$55	\$146,296	2.1%	-7.2%
AEPSC350	1	\$ 160,253	\$32,051	\$192,304	\$7,000	\$ 199,304		\$170,460	\$18,034	\$188,494	\$0	\$188,494	5.7%	-15.0%
AEPSC351	2	\$ 105,975	\$10,598	\$116,573	\$0	\$ 116,573		\$111,873	\$4,267	\$116,140	\$174	\$116,314	0.2%	-8.9%
AEPSC352	2	\$ 75,840	\$6,067	\$81,907	\$0	\$ 81,907		\$73,524	\$1,291	\$74,815	\$0	\$74,815	9.5%	1.4%
AEPSC353	1	\$ 105,217	\$10,522	\$115,739	\$0	\$ 115,739		\$98,615	\$5,229	\$103,844	-\$153	\$103,691	11.6%	1.5%
AEPSC354	1	\$ 124,445	\$12,444	\$136,889	\$0	\$ 136,889		\$129,253	\$8,847	\$138,100	\$1,206	\$139,306	-1.7%	-10.7%
AEPSC355	1	\$ 180,718	\$36,144	\$216,862	\$7,000	\$ 223,862		\$166,509	\$22,687	\$189,196	\$4,216	\$193,412	15.7%	-6.6%
AEPSC356	1	\$ 63,750	\$5,100	\$68,850	\$0	\$ 68,850		\$79,855	\$3,268	\$83,123	\$132	\$83,255	-17.3%	-23.4%
AEPSC357	2	\$ 95,767	\$9,577	\$105,344	\$0	\$ 105,344		\$102,729	\$5,472	\$108,201	\$1,407	\$109,608	-3.9%	-12.6%
AEPSC358	2	\$ 132,761	\$19,914	\$152,675	\$0	\$ 152,675		\$146,404	\$21,486	\$167,890	\$1,525	\$169,415	-9.9%	-21.6%
AEPSC359	4	\$ 109,690	\$10,969	\$120,659	\$0	\$ 120,659		\$134,716	\$13,331	\$148,047	-\$493	\$147,554	-18.2%	-25.7%
AEPSC360	1	\$ 185,336	\$37,067	\$222,403	\$7,000	\$ 229,403		\$153,615	\$30,239	\$183,854	\$0	\$183,854	24.8%	0.8%
AEPSC361	4	\$ 184,923	\$36,985	\$221,907	\$7,000	\$ 228,907		\$180,018	\$14,861	\$194,879	\$9,817	\$204,696	11.8%	-9.7%
AEPSC362	1	\$ 115,440	\$11,544	\$126,984	\$0	\$ 126,984		\$126,304	\$5,941	\$132,245	\$0	\$132,245	-4.0%	-12.7%
AEPSC363	1	\$ 106,145	\$10,615	\$116,760	\$0	\$ 116,760		\$99,820	\$3,507	\$103,327	\$94	\$103,421	12.9%	2.6%
AEPSC364	2	\$ 138,922	\$20,838	\$159,761	\$0	\$ 159,761		\$160,182	\$24,649	\$184,831	\$0	\$184,831	-13.6%	-24.8%
AEPSC365	3	\$ 69,345	\$5,548	\$74,892	\$0	\$ 74,892		\$74,236	\$1,647	\$75,883	-\$29	\$75,854	-1.3%	-8.6%</

		AEP Incumbent Data						Survey Results <sup>1</sup>					% Difference	
			Target Short-Term Incentive (STI)	Target Total Cash Compensation n (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)				Long-Term Incentive (LTI)			Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>
Job Identifier <sup>2</sup>	Incumbent Count	Avg Base					Base	Target STI	Target TCC		Target TC			
AEPSC375	1	\$ 214,240	\$64,272	\$278,512	\$48,500	\$ 327,012	\$337,009	\$114,631	\$451,640	\$90,909	\$542,549		-39.7%	-60.5%
AEPSC376	1	\$ 247,200	\$86,520	\$333,720	\$93,000	\$ 426,720	\$312,737	\$112,701	\$425,438	\$141,508	\$566,946		-24.7%	-56.4%
AEPSC377	1	\$ 242,500	\$84,875	\$327,375	\$93,000	\$ 420,375	\$252,407	\$53,351	\$305,758	\$33,700	\$339,458		23.8%	-28.6%
AEPSC378	1	\$ 221,220	\$66,366	\$287,586	\$48,500	\$ 336,086	\$224,517	\$61,223	\$285,740	\$48,496	\$334,236		0.6%	-33.8%
AEPSC379	1	\$ 226,008	\$67,802	\$293,810	\$48,500	\$ 342,310	\$215,886	\$45,816	\$261,702	\$37,886	\$299,588		14.3%	-24.6%
AEPSC380	2	\$ 79,871	\$7,188	\$87,060	\$0	\$ 87,060	\$90,837	\$3,355	\$94,192	\$270	\$94,462		-7.8%	-15.4%
AEPSC381	3	\$ 73,572	\$5,886	\$79,458	\$0	\$ 79,458	\$74,305	\$2,388	\$76,693	\$118	\$76,811		3.4%	-4.2%
AEPSC382	3	\$ 120,067	\$12,007	\$132,074	\$0	\$ 132,074	\$142,040	\$9,455	\$151,495	\$756	\$152,251		-13.3%	-21.1%
AEPSC383	3	\$ 93,022	\$9,302	\$102,324	\$0	\$ 102,324	\$116,403	\$5,737	\$122,140	\$185	\$122,325		-16.4%	-24.0%
AEPSC384	4	\$ 93,099	\$9,310	\$102,408	\$0	\$ 102,408	\$109,173	\$8,548	\$117,721	\$96	\$117,817		-13.1%	-21.0%
AEPSC385	2	\$ 143,884	\$21,583	\$165,466	\$0	\$ 165,466	\$147,185	\$23,586	\$170,771	\$0	\$170,771		-3.1%	-15.7%
AEPSC386	5	\$ 116,352	\$11,635	\$127,988	\$0	\$ 127,988	\$133,988	\$14,293	\$148,281	\$110	\$148,391		-13.7%	-21.6%
AEPSC387	1	\$ 143,859	\$14,386	\$158,245	\$0	\$ 158,245	\$96,653	-\$1,951	\$94,702	\$18	\$94,720		67.1%	51.9%
AEPSC388	2	\$ 122,304	\$12,230	\$134,534	\$0	\$ 134,534	\$120,349	\$12,611	\$132,960	\$4	\$132,964		1.2%	-8.0%
AEPSC389	1	\$ 104,638	\$10,464	\$115,102	\$0	\$ 115,102	\$106,150	\$3,967	\$110,117	\$0	\$110,117		4.5%	-5.0%
AEPSC390	1	\$ 77,250	\$6,953	\$84,203	\$0	\$ 84,203	\$89,612	\$3,856	\$93,468	\$193	\$93,661		-10.1%	-17.5%
AEPSC391	1	\$ 76,250	\$6,863	\$83,113	\$0	\$ 83,113	\$102,507	\$9,736	\$112,243	\$0	\$112,243		-26.0%	-32.1%
AEPSC392	1	\$ 90,742	\$8,167	\$98,909	\$0	\$ 98,909	\$114,941	\$9,765	\$124,706	\$598	\$125,304		-21.1%	-27.6%
AEPSC393	1	\$ 134,264	\$13,426	\$147,690	\$0	\$ 147,690	\$131,642	\$10,821	\$142,463	\$51	\$142,514		3.6%	-5.8%
AEPSC394	1	\$ 129,540	\$12,954	\$142,494	\$0	\$ 142,494	\$136,436	\$26,875	\$163,311	\$0	\$163,311		-12.7%	-20.7%
AEPSC395	1	\$ 114,171	\$11,417	\$125,588	\$0	\$ 125,588	\$123,725	\$6,800	\$130,525	\$1,643	\$132,168		-5.0%	-13.6%
AEPSC396	24	\$ 119,607	\$11,961	\$131,567	\$0	\$ 131,567	\$129,877	\$10,117	\$139,994	\$682	\$140,676		-6.5%	-15.0%
AEPSC397	44	\$ 100,709	\$10,071	\$110,780	\$0	\$ 110,780	\$101,878	\$10,081	\$111,959	\$28	\$111,987		-1.1%	-10.1%
AEPSC398	43	\$ 136,235	\$20,435	\$156,670	\$0	\$ 156,670	\$142,425	\$20,679	\$163,104	\$1,152	\$164,256		-4.6%	-17.1%
AEPSC399	70	\$ 117,746	\$11,775	\$129,520	\$0	\$ 129,520	\$121,344	\$15,236	\$136,580	\$378	\$136,958		-5.4%	-14.0%
AEPSC400	1	\$ 76,000	\$6,840	\$82,840	\$0	\$ 82,840	\$96,783	\$5,495	\$102,278	\$466	\$102,744		-19.4%	-26.0%
AEPSC401	7	\$ 65,145	\$5,212	\$70,356	\$0	\$ 70,356	\$78,051	\$3,122	\$81,173	\$241	\$81,414		-13.6%	-20.0%
AEPSC402	6	\$ 86,826	\$7,814	\$94,640	\$0	\$ 94,640	\$90,738	-\$437	\$90,301	\$396	\$90,697		4.3%	-4.3%
AEPSC403	3	\$ 109,137	\$10,914	\$120,051	\$0	\$ 120,051	\$149,954	\$18,435	\$168,389	\$10,781	\$179,170		-33.0%	-39.1%
AEPSC404	1	\$ 145,000	\$29,000	\$174,000	\$7,000	\$ 181,000	\$173,292	\$29,626	\$202,918	\$7,376	\$210,294		-13.9%	-31.0%
AEPSC405	2	\$ 134,775	\$20,216	\$154,991	\$0	\$ 154,991	\$125,895	\$15,596	\$141,491	\$57	\$141,548		9.5%	-4.8%
AEPSC406	6	\$ 158,989	\$31,798	\$190,787	\$7,000	\$ 197,787	\$157,492	\$28,347	\$185,839	\$2,509	\$188,348		5.0%	-15.6%
AEPSC407	1	\$ 157,725	\$23,659	\$181,383	\$0	\$ 181,383	\$150,916	\$26,443	\$177,359	\$719	\$178,078		1.9%	-11.4%
AEPSC408	4	\$ 94,487	\$9,449	\$103,936	\$0	\$ 103,936	\$103,088	\$4,632	\$107,720	\$1,552	\$109,272		-4.9%	-13.5%
AEPSC409	2	\$ 111,108	\$11,111	\$122,219	\$0	\$ 122,219	\$130,378	\$6,368	\$136,746	\$960	\$137,706		-11.2%	-19.3%
AEPSC410	1	\$ 177,225	\$35,445	\$212,670	\$7,000	\$ 219,670	\$154,326	\$14,448	\$168,774	\$420	\$169,194		29.8%	4.7%
AEPSC411	5	\$ 179,532	\$35,906	\$215,439	\$7,000	\$ 222,439	\$165,556	\$27,264	\$192,820	\$4,525	\$197,345		12.7%	-9.0%
AEPSC412	10	\$ 83,617	\$7,526	\$91,142	\$0	\$ 91,142	\$87,363	\$6,993	\$94,356	\$0	\$94,356		-3.4%	-11.4%
AEPSC413	13	\$ 110,830	\$11,083	\$121,913	\$0	\$ 121,913	\$135,578	\$18,593	\$154,171	-\$26	\$154,145		-20.9%	-28.1%
AEPSC414	18	\$ 97,284	\$9,728	\$107,013	\$0	\$ 107,013	\$107,601	\$10,746	\$118,347	\$707	\$119,054		-10.1%	-18.3%
AEPSC415	1	\$ 102,713	\$10,271	\$112,985	\$0	\$ 112,985	\$99,177	\$4,537	\$103,714	\$94	\$103,808		8.8%	-1.1%
AEPSC416	1	\$ 88,000	\$7,920	\$95,920	\$0	\$ 95,920	\$89,749	\$8,057	\$97,806	\$799	\$98,605		-2.7%	-10.8%
AEPSC417	1	\$ 101,001	\$10,100	\$111,101	\$0	\$ 111,101	\$109,652	\$13,008	\$122,660	\$2,260	\$124,920		-11.1%	-19.1%
AEPSC418	2	\$ 73,559	\$5,885	\$79,444	\$0	\$ 79,444	\$76,740	\$6,459	\$83,199	\$0	\$83,199		-4.5%	-11.6%
AEPSC419	2	\$ 84,172	\$7,575	\$91,747	\$0	\$ 91,747	\$89,749	\$8,057	\$97,806	\$799	\$98,605		-7.0%	-14.6%
AEPSC420	1	\$ 82,352	\$7,412	\$89,764	\$0	\$ 89,764	\$84,782	\$10,461	\$95,243	\$449	\$95,692		-6.2%	-13.9%
AEPSC421	1	\$ 162,318	\$32,464	\$194,781	\$7,000	\$ 201,781	\$165,556	\$27,264	\$192,820	\$4,525	\$197,345		2.2%	-17.7%
AEPSC422	5	\$ 112,495	\$11,250	\$123,745	\$0	\$ 123,745	\$136,615	\$8,652	\$145,267	\$338	\$145,605		-15.0%	-22.7%
AEPSC423	1	\$ 108,708	\$10,871	\$119,578	\$0	\$ 119,578	\$109,752	\$4,922	\$114,674	-\$164	\$114,510		4.4%	-5.1%
AEPSC424	1	\$ 85,642	\$7,708	\$93,350	\$0	\$ 93,350	\$87,724	\$4,870	\$92,594	\$0	\$92,594		0.8%	-7.5%
AEPSC425	7	\$ 105,152	\$10,515	\$115,668	\$0	\$ 115,668	\$104,495	\$5,440	\$109,935	\$0	\$109,935		5.2%	-4.4%
AEPSC426	1	\$ 91,500	\$8,235	\$99,735	\$0	\$ 99,735	\$81,667	\$7,427	\$89,094	\$0	\$89,094		11.9%	2.7%
AEPSC427	9	\$ 136,718	\$20,508	\$157,226	\$0	\$ 157,226	\$151,698	\$16,324	\$168,022	\$0	\$168,022		-6.4%	-18.6%
AEPSC428	20	\$ 121,195	\$12,120	\$133,315	\$0	\$ 133,315	\$145,885	\$10,144	\$156,029	\$0	\$156,029		-14.6%	-22.3%
AEPSC429	3	\$ 142,653	\$21,398	\$164,051	\$0	\$ 164,051	\$151,698	\$16,324	\$168,022	\$0	\$168,022		-2.4%	-15.1%
AEPSC430	2	\$ 125,936	\$12,594	\$138,530	\$0	\$ 138,530	\$128,684	\$14,039	\$142,723	\$0	\$142,723		-2.9%	-11.8%
AEPSC431	1	\$ 169,618	\$25,443	\$195,061	\$0	\$ 195,061	\$134,231	\$9,346	\$143,577	\$2,062	\$145,639		33.9%	16.5%
AEPSC432	2	\$ 158,013	\$31,603	\$189,616	\$7,000	\$ 196,616	\$196,730	\$40,634	\$237,364	\$6,508	\$243,872		-19.4%	-35.2%
AEPSC433	12	\$ 158,828	\$31,766	\$190,594	\$7,000	\$ 197,594	\$193,775	\$36,507	\$230,282	\$20,801	\$251,083		-21.3%	-36.7%
AEPSC434	6	\$ 152,227	\$30,445	\$182,672	\$7,000	\$ 189,672	\$190,212	\$44,680	\$234,892	\$6,597	\$241,489		-21.5%	-37.0%
AEPSC435	17	\$ 139,468	\$20,920	\$160,388	\$0	\$ 160,388	\$138,730	\$19,114	\$157,844	\$192	\$158,036		1.5%	-11.7%
AEPSC436	2	\$ 134,276	\$20,141	\$154,418	\$0	\$ 154,418	\$135,433	\$11,259	\$146,692	\$0	\$146,692		5.3%	-8.5%
AEPSC437	2	\$ 153,657	\$23,049	\$176,705	\$0	\$ 176,705	\$135,433	\$11,259	\$146,692	\$0	\$146,692		20.5%	4.7%
AEPSC438	3	\$ 93,252	\$8,393	\$101,644	\$0	\$ 101,644	\$81,626	\$4,356	\$85,982	\$110	\$86,092		18.1%	

		AEP Incumbent Data					Survey Results <sup>1</sup>					% Difference		
Job Identifier <sup>2</sup>	Incumbent Count		Target Short-Term Incentive (STI)	Target Total Cash Compensation (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)				Long-Term Incentive (LTI)		Target TCC vs Survey Target TCC <sup>3</sup>	Base vs Survey Target TCC <sup>3</sup>	
		Avg Base					Base	Target STI	Target TCC		Target TC			
AEPSC461	3	\$ 173,369	\$43,342	\$216,712	\$25,000	\$ 241,712	\$198,071	\$49,518	\$247,589	\$21,947	\$269,536	-10.3%	-35.7%	
AEPSC462	5	\$ 152,740	\$30,548	\$183,288	\$7,000	\$ 190,288	\$177,237	\$25,641	\$202,878	\$1,369	\$204,247	-6.8%	-25.2%	
AEPSC463	5	\$ 173,364	\$43,341	\$216,705	\$25,000	\$ 241,705	\$193,775	\$36,507	\$230,282	\$20,801	\$251,083	-3.7%	-31.0%	
AEPSC464	12	\$ 155,245	\$31,049	\$186,294	\$7,000	\$ 193,294	\$158,966	\$21,671	\$180,637	\$2,226	\$182,863	5.7%	-15.1%	
AEPSC465	1	\$ 126,117	\$12,612	\$138,728	\$0	\$ 138,728	\$146,729	\$19,655	\$166,384	-\$201	\$166,183	-16.5%	-24.1%	
AEPSC466	19	\$ 88,163	\$7,935	\$96,098	\$0	\$ 96,098	\$89,749	\$8,057	\$97,806	\$799	\$98,605	-2.5%	-10.6%	
AEPSC467	2	\$ 79,968	\$6,397	\$86,365	\$0	\$ 86,365	\$76,740	\$6,459	\$83,199	\$0	\$83,199	3.8%	-3.9%	
AEPSC468	2	\$ 130,834	\$13,083	\$143,918	\$0	\$ 143,918	\$129,783	\$19,058	\$148,841	\$3,359	\$152,200	-5.4%	-14.0%	
AEPSC469	5	\$ 99,378	\$9,938	\$109,316	\$0	\$ 109,316	\$109,652	\$13,008	\$122,660	\$2,260	\$124,920	-12.5%	-20.4%	
AEPSC470	7	\$ 126,944	\$19,042	\$145,985	\$0	\$ 145,985	\$150,865	\$24,645	\$175,510	\$868	\$176,378	-17.2%	-28.0%	
AEPSC471	2	\$ 157,609	\$31,522	\$189,131	\$7,000	\$ 196,131	\$196,730	\$40,634	\$237,364	\$6,508	\$243,872	-19.6%	-35.4%	
AEPSC472	1	\$ 143,917	\$28,783	\$172,700	\$7,000	\$ 179,700	\$142,659	\$26,483	\$169,142	\$0	\$169,142	6.2%	-14.9%	
AEPSC473	7	\$ 68,176	\$5,454	\$73,630	\$0	\$ 73,630	\$77,277	\$4,619	\$81,896	\$40	\$81,936	-10.1%	-16.8%	
AEPSC474	1	\$ 55,000	\$3,300	\$58,300	\$0	\$ 58,300	\$64,678	\$4,179	\$68,857	\$0	\$68,857	-15.3%	-20.1%	
AEPSC475	1	\$ 93,209	\$9,321	\$102,530	\$0	\$ 102,530	\$118,720	\$7,804	\$126,524	\$0	\$126,524	-19.0%	-26.3%	
AEPSC476	9	\$ 86,211	\$7,759	\$93,970	\$0	\$ 93,970	\$101,002	\$9,938	\$110,940	\$1,830	\$112,770	-16.7%	-23.6%	
AEPSC477	1	\$ 177,476	\$35,495	\$212,971	\$7,000	\$ 219,971	\$172,025	\$25,825	\$197,850	\$5,603	\$203,453	8.1%	-12.8%	
AEPSC478	1	\$ 125,000	\$12,500	\$137,500	\$0	\$ 137,500	\$124,882	\$7,862	\$132,744	\$359	\$133,103	3.3%	-6.1%	
AEPSC479	1	\$ 140,929	\$21,139	\$162,068	\$0	\$ 162,068	\$142,040	\$9,455	\$151,495	\$756	\$152,251	6.4%	-7.4%	
AEPSC Incumbent Count:		2,683						Number of Jobs with Significant STI		521	AEPSC Average:		-1.9%	-15.9%
AEPSC Job Count:		479						Number of Jobs without Significant STI		7	GRAND AVERAGE:		-2.4%	-16.0%
GRAND TOTAL INCUMBENT COUNT:		2,754								% of Jobs Below Market Competitive Range <sup>3</sup>		15%	56%	
GRAND TOTAL JOB COUNT:		528								% of Jobs Above Market Competitive Range <sup>3</sup>		10%	2%	

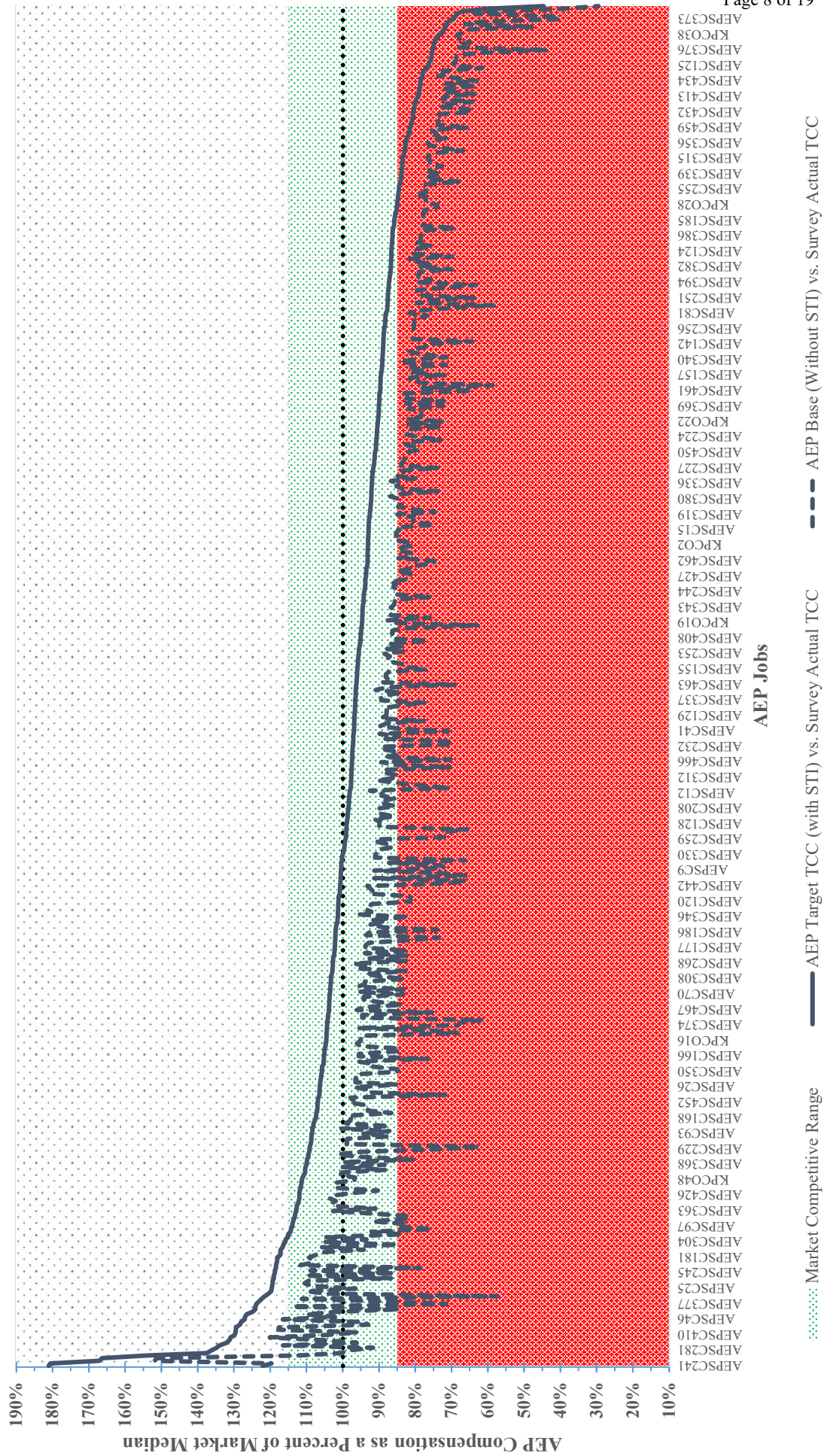
**Notes:**

<sup>1</sup> Survey Data from the 2024 Willis Towers Watson Energy Services and General Industry Middle Management, Professional & Support surveys or, in a few cases, the 2024 Willis Towers Watson Energy Services and General Industry Executive Compensation Surveys, in all cases aged from April 1, 2024 to May 31, 2025 at 3.5% annual rate.

<sup>2</sup> Includes all Kentucky Power Company and AEPSC jobs as of May 31, 2025 for which there was a matching survey job with a sufficient sample of compensation survey information.

<sup>3</sup> A market competitive range of +/- 15 percent has been used for these salaried nonexempt positions.

**Figure ARC-8**  
**KPCO and AEPSC Exempt Non-Officer Positions**  
**vs. Market-Competitive Compensation (High to Low)**  
**With and Without STI**



<b><u>AEP Job</u></b>	<b>AEP Target TCC (with STI) vs. Survey Actual TCC</b>	<b>AEP Base (Without STI) vs. Survey Actual TCC</b>	<b>Market Low</b>	<b>Market Median Compensation</b>	<b>Market Competitive Range</b>	<b>Market Max</b>
AEPSC241	181.1%	122.1%	85.0%	100.0%	30.0%	75.0%
AEPSC141	180.6%	119.7%	85.0%	100.0%	30.0%	75.0%
AEPSC387	167.1%	151.9%	85.0%	100.0%	30.0%	75.0%
AEPSC239	166.4%	151.3%	85.0%	100.0%	30.0%	75.0%
AEPSC131	154.0%	112.4%	85.0%	100.0%	30.0%	75.0%
AEPSC117	137.5%	100.5%	85.0%	100.0%	30.0%	75.0%
AEPSC281	136.2%	98.6%	85.0%	100.0%	30.0%	75.0%
AEPSC370	134.8%	91.6%	85.0%	100.0%	30.0%	75.0%
AEPSC431	133.9%	116.5%	85.0%	100.0%	30.0%	75.0%
AEPSC159	132.0%	96.2%	85.0%	100.0%	30.0%	75.0%
AEPSC324	131.2%	105.9%	85.0%	100.0%	30.0%	75.0%
AEPSC42	130.9%	120.1%	85.0%	100.0%	30.0%	75.0%
AEPSC410	129.8%	104.7%	85.0%	100.0%	30.0%	75.0%
AEPSC289	129.6%	95.9%	85.0%	100.0%	30.0%	75.0%
AEPSC92	129.5%	117.7%	85.0%	100.0%	30.0%	75.0%
AEPSC110	129.4%	117.6%	85.0%	100.0%	30.0%	75.0%
KPCO11	128.3%	93.0%	85.0%	100.0%	30.0%	75.0%
AEPSC191	128.0%	94.1%	85.0%	100.0%	30.0%	75.0%
AEPSC46	127.0%	116.5%	85.0%	100.0%	30.0%	75.0%
AEPSC332	127.0%	102.1%	85.0%	100.0%	30.0%	75.0%
KPCO29	126.5%	110.0%	85.0%	100.0%	30.0%	75.0%
AEPSC360	124.8%	100.8%	85.0%	100.0%	30.0%	75.0%
AEPSC282	124.1%	84.3%	85.0%	100.0%	30.0%	75.0%
AEPSC14	124.1%	113.8%	85.0%	100.0%	30.0%	75.0%
AEPSC377	123.8%	71.4%	85.0%	100.0%	30.0%	75.0%
KPCO43	123.1%	88.1%	85.0%	100.0%	30.0%	75.0%
AEPSC49	122.4%	111.3%	85.0%	100.0%	30.0%	75.0%
AEPSC235	121.5%	57.2%	85.0%	100.0%	30.0%	75.0%
AEPSC437	120.5%	104.7%	85.0%	100.0%	30.0%	75.0%
AEPSC63	119.7%	109.8%	85.0%	100.0%	30.0%	75.0%
AEPSC25	119.6%	96.5%	85.0%	100.0%	30.0%	75.0%
AEPSC212	119.5%	108.6%	85.0%	100.0%	30.0%	75.0%
AEPSC21	119.3%	110.5%	85.0%	100.0%	30.0%	75.0%
AEPSC22	119.3%	109.5%	85.0%	100.0%	30.0%	75.0%
AEPSC184	119.0%	86.7%	85.0%	100.0%	30.0%	75.0%
AEPSC193	119.0%	110.2%	85.0%	100.0%	30.0%	75.0%
AEPSC245	118.8%	86.0%	85.0%	100.0%	30.0%	75.0%
AEPSC242	118.7%	108.9%	85.0%	100.0%	30.0%	75.0%
AEPSC280	118.4%	78.5%	85.0%	100.0%	30.0%	75.0%
AEPSC165	118.4%	111.7%	85.0%	100.0%	30.0%	75.0%
AEPSC446	118.2%	108.4%	85.0%	100.0%	30.0%	75.0%
AEPSC438	118.1%	108.3%	85.0%	100.0%	30.0%	75.0%
AEPSC181	118.0%	109.3%	85.0%	100.0%	30.0%	75.0%
AEPSC243	117.2%	107.5%	85.0%	100.0%	30.0%	75.0%
AEPSC202	117.2%	106.5%	85.0%	100.0%	30.0%	75.0%
AEPSC197	117.1%	94.2%	85.0%	100.0%	30.0%	75.0%
AEPSC254	116.5%	105.9%	85.0%	100.0%	30.0%	75.0%
AEPSC150	116.4%	84.9%	85.0%	100.0%	30.0%	75.0%



AEPSC304	115.9%	105.3%	85.0%	100.0%	30.0%	75.0%
AEPSC355	115.7%	93.4%	85.0%	100.0%	30.0%	75.0%
AEPSC344	115.1%	104.6%	85.0%	100.0%	30.0%	75.0%
AEPSC240	115.1%	83.6%	85.0%	100.0%	30.0%	75.0%
AEPSC136	114.3%	92.0%	85.0%	100.0%	30.0%	75.0%
AEPSC379	114.3%	75.4%	85.0%	100.0%	30.0%	75.0%
AEPSC97	113.9%	83.8%	85.0%	100.0%	30.0%	75.0%
AEPSC288	113.9%	82.3%	85.0%	100.0%	30.0%	75.0%
AEPSC440	113.7%	91.6%	85.0%	100.0%	30.0%	75.0%
AEPSC69	113.4%	83.0%	85.0%	100.0%	30.0%	75.0%
AEPSC161	113.2%	81.3%	85.0%	100.0%	30.0%	75.0%
AEPSC198	113.1%	91.2%	85.0%	100.0%	30.0%	75.0%
AEPSC363	112.9%	102.6%	85.0%	100.0%	30.0%	75.0%
AEPSC411	112.7%	91.0%	85.0%	100.0%	30.0%	75.0%
AEPSC297	112.7%	102.4%	85.0%	100.0%	30.0%	75.0%
AEPSC133	112.3%	103.0%	85.0%	100.0%	30.0%	75.0%
AEPSC201	112.1%	102.0%	85.0%	100.0%	30.0%	75.0%
KPCO17	112.0%	103.7%	85.0%	100.0%	30.0%	75.0%
AEPSC426	111.9%	102.7%	85.0%	100.0%	30.0%	75.0%
AEPSC233	111.9%	97.3%	85.0%	100.0%	30.0%	75.0%
AEPSC361	111.8%	90.3%	85.0%	100.0%	30.0%	75.0%
AEPSC353	111.6%	101.5%	85.0%	100.0%	30.0%	75.0%
AEPSC247	111.5%	102.3%	85.0%	100.0%	30.0%	75.0%
AEPSC218	111.4%	102.2%	85.0%	100.0%	30.0%	75.0%
KPCO48	111.3%	96.8%	85.0%	100.0%	30.0%	75.0%
AEPSC248	111.1%	96.6%	85.0%	100.0%	30.0%	75.0%
AEPSC269	110.7%	100.6%	85.0%	100.0%	30.0%	75.0%
AEPSC279	110.4%	100.3%	85.0%	100.0%	30.0%	75.0%
AEPSC262	110.3%	88.3%	85.0%	100.0%	30.0%	75.0%
AEPSC192	110.3%	100.3%	85.0%	100.0%	30.0%	75.0%
AEPSC368	110.0%	88.5%	85.0%	100.0%	30.0%	75.0%
AEPSC80	109.9%	99.9%	85.0%	100.0%	30.0%	75.0%
AEPSC118	109.8%	80.4%	85.0%	100.0%	30.0%	75.0%
AEPSC405	109.5%	95.2%	85.0%	100.0%	30.0%	75.0%
AEPSC352	109.5%	101.4%	85.0%	100.0%	30.0%	75.0%
KPCO20	109.3%	95.0%	85.0%	100.0%	30.0%	75.0%
AEPSC229	109.1%	73.0%	85.0%	100.0%	30.0%	75.0%
AEPSC89	109.1%	62.3%	85.0%	100.0%	30.0%	75.0%
AEPSC415	108.8%	98.9%	85.0%	100.0%	30.0%	75.0%
AEPSC329	108.7%	98.8%	85.0%	100.0%	30.0%	75.0%
AEPSC333	108.6%	98.8%	85.0%	100.0%	30.0%	75.0%
AEPSC24	108.6%	87.3%	85.0%	100.0%	30.0%	75.0%
AEPSC93	108.5%	94.3%	85.0%	100.0%	30.0%	75.0%
AEPSC35	108.4%	87.2%	85.0%	100.0%	30.0%	75.0%
AEPSC139	108.3%	100.3%	85.0%	100.0%	30.0%	75.0%
AEPSC477	108.1%	87.2%	85.0%	100.0%	30.0%	75.0%
AEPSC143	108.0%	99.1%	85.0%	100.0%	30.0%	75.0%
AEPSC51	107.7%	97.9%	85.0%	100.0%	30.0%	75.0%
AEPSC168	107.4%	97.7%	85.0%	100.0%	30.0%	75.0%
AEPSC34	107.3%	98.5%	85.0%	100.0%	30.0%	75.0%
AEPSC246	107.3%	86.6%	85.0%	100.0%	30.0%	75.0%
AEPSC326	107.1%	93.1%	85.0%	100.0%	30.0%	75.0%

AEPSC189	107.0%	93.0%	85.0%	100.0%	30.0%	75.0%
AEPSC119	107.0%	93.0%	85.0%	100.0%	30.0%	75.0%
AEPSC452	106.9%	98.1%	85.0%	100.0%	30.0%	75.0%
AEPSC274	106.9%	97.1%	85.0%	100.0%	30.0%	75.0%
AEPSC194	106.7%	97.9%	85.0%	100.0%	30.0%	75.0%
AEPSC291	106.5%	71.8%	85.0%	100.0%	30.0%	75.0%
AEPSC479	106.4%	92.6%	85.0%	100.0%	30.0%	75.0%
AEPSC306	106.4%	92.5%	85.0%	100.0%	30.0%	75.0%
AEPSC26	106.3%	96.7%	85.0%	100.0%	30.0%	75.0%
AEPSC472	106.2%	85.1%	85.0%	100.0%	30.0%	75.0%
AEPSC327	106.1%	96.5%	85.0%	100.0%	30.0%	75.0%
AEPSC366	106.1%	96.5%	85.0%	100.0%	30.0%	75.0%
AEPSC317	105.9%	96.3%	85.0%	100.0%	30.0%	75.0%
KPCO4	105.9%	96.3%	85.0%	100.0%	30.0%	75.0%
AEPSC350	105.7%	85.0%	85.0%	100.0%	30.0%	75.0%
AEPSC464	105.7%	84.9%	85.0%	100.0%	30.0%	75.0%
AEPSC278	105.7%	91.9%	85.0%	100.0%	30.0%	75.0%
AEPSC436	105.3%	91.5%	85.0%	100.0%	30.0%	75.0%
AEPSC425	105.2%	95.6%	85.0%	100.0%	30.0%	75.0%
AEPSC90	105.2%	76.4%	85.0%	100.0%	30.0%	75.0%
AEPSC166	105.2%	95.6%	85.0%	100.0%	30.0%	75.0%
AEPSC292	105.1%	95.5%	85.0%	100.0%	30.0%	75.0%
AEPSC77	105.0%	84.6%	85.0%	100.0%	30.0%	75.0%
AEPSC406	105.0%	84.4%	85.0%	100.0%	30.0%	75.0%
AEPSC328	104.7%	95.2%	85.0%	100.0%	30.0%	75.0%
AEPSC102	104.7%	96.1%	85.0%	100.0%	30.0%	75.0%
KPCO16	104.5%	95.0%	85.0%	100.0%	30.0%	75.0%
AEPSC389	104.5%	95.0%	85.0%	100.0%	30.0%	75.0%
AEPSC423	104.4%	94.9%	85.0%	100.0%	30.0%	75.0%
AEPSC371	104.4%	68.3%	85.0%	100.0%	30.0%	75.0%
AEPSC205	104.4%	76.1%	85.0%	100.0%	30.0%	75.0%
AEPSC402	104.3%	95.7%	85.0%	100.0%	30.0%	75.0%
AEPSC374	104.3%	68.2%	85.0%	100.0%	30.0%	75.0%
AEPSC290	104.2%	67.6%	85.0%	100.0%	30.0%	75.0%
AEPSC91	104.2%	61.7%	85.0%	100.0%	30.0%	75.0%
KPCO30	104.1%	94.6%	85.0%	100.0%	30.0%	75.0%
KPCO3	104.1%	94.6%	85.0%	100.0%	30.0%	75.0%
AEPSC68	103.9%	75.4%	85.0%	100.0%	30.0%	75.0%
AEPSC467	103.8%	96.1%	85.0%	100.0%	30.0%	75.0%
AEPSC221	103.8%	94.3%	85.0%	100.0%	30.0%	75.0%
AEPSC10	103.7%	83.4%	85.0%	100.0%	30.0%	75.0%
AEPSC270	103.7%	90.2%	85.0%	100.0%	30.0%	75.0%
AEPSC393	103.6%	94.2%	85.0%	100.0%	30.0%	75.0%
AEPSC52	103.6%	94.2%	85.0%	100.0%	30.0%	75.0%
AEPSC70	103.6%	83.3%	85.0%	100.0%	30.0%	75.0%
AEPSC381	103.4%	95.8%	85.0%	100.0%	30.0%	75.0%
AEPSC79	103.4%	83.2%	85.0%	100.0%	30.0%	75.0%
KPCO5	103.4%	95.7%	85.0%	100.0%	30.0%	75.0%
AEPSC478	103.3%	93.9%	85.0%	100.0%	30.0%	75.0%
AEPSC348	103.3%	93.9%	85.0%	100.0%	30.0%	75.0%
AEPSC308	103.2%	83.0%	85.0%	100.0%	30.0%	75.0%
AEPSC206	103.2%	89.8%	85.0%	100.0%	30.0%	75.0%

AEPSC445	103.0%	93.7%	85.0%	100.0%	30.0%	75.0%
AEPSC104	102.9%	82.7%	85.0%	100.0%	30.0%	75.0%
AEPSC267	102.8%	95.2%	85.0%	100.0%	30.0%	75.0%
AEPSC82	102.7%	93.4%	85.0%	100.0%	30.0%	75.0%
AEPSC268	102.7%	96.9%	85.0%	100.0%	30.0%	75.0%
AEPSC158	102.7%	82.6%	85.0%	100.0%	30.0%	75.0%
AEPSC3	102.7%	93.3%	85.0%	100.0%	30.0%	75.0%
AEPSC183	102.4%	82.0%	85.0%	100.0%	30.0%	75.0%
AEPSC146	102.3%	93.9%	85.0%	100.0%	30.0%	75.0%
AEPSC421	102.2%	82.3%	85.0%	100.0%	30.0%	75.0%
AEPSC177	102.2%	93.7%	85.0%	100.0%	30.0%	75.0%
AEPSC171	102.1%	93.7%	85.0%	100.0%	30.0%	75.0%
AEPSC349	102.1%	92.8%	85.0%	100.0%	30.0%	75.0%
AEPSC62	102.1%	82.1%	85.0%	100.0%	30.0%	75.0%
AEPSC153	102.0%	73.5%	85.0%	100.0%	30.0%	75.0%
AEPSC182	102.0%	93.6%	85.0%	100.0%	30.0%	75.0%
AEPSC186	102.0%	92.7%	85.0%	100.0%	30.0%	75.0%
AEPSC285	101.9%	74.0%	85.0%	100.0%	30.0%	75.0%
AEPSC407	101.9%	88.6%	85.0%	100.0%	30.0%	75.0%
AEPSC45	101.7%	92.5%	85.0%	100.0%	30.0%	75.0%
AEPSC435	101.5%	88.3%	85.0%	100.0%	30.0%	75.0%
AEPSC294	101.5%	92.2%	85.0%	100.0%	30.0%	75.0%
AEPSC346	101.3%	81.7%	85.0%	100.0%	30.0%	75.0%
AEPSC257	101.3%	95.6%	85.0%	100.0%	30.0%	75.0%
AEPSC29	101.3%	92.1%	85.0%	100.0%	30.0%	75.0%
AEPSC301	101.3%	93.8%	85.0%	100.0%	30.0%	75.0%
KPCO32	101.2%	92.9%	85.0%	100.0%	30.0%	75.0%
AEPSC388	101.2%	92.0%	85.0%	100.0%	30.0%	75.0%
AEPSC120	101.2%	81.3%	85.0%	100.0%	30.0%	75.0%
AEPSC293	101.2%	81.3%	85.0%	100.0%	30.0%	75.0%
AEPSC276	101.1%	81.5%	85.0%	100.0%	30.0%	75.0%
AEPSC424	100.8%	92.5%	85.0%	100.0%	30.0%	75.0%
KPCO6	100.8%	91.6%	85.0%	100.0%	30.0%	75.0%
AEPSC47	100.7%	92.4%	85.0%	100.0%	30.0%	75.0%
AEPSC442	100.7%	93.3%	85.0%	100.0%	30.0%	75.0%
AEPSC172	100.7%	72.3%	85.0%	100.0%	30.0%	75.0%
AEPSC283	100.6%	66.0%	85.0%	100.0%	30.0%	75.0%
AEPSC94	100.6%	91.5%	85.0%	100.0%	30.0%	75.0%
AEPSC378	100.6%	66.2%	85.0%	100.0%	30.0%	75.0%
AEPSC215	100.5%	72.8%	85.0%	100.0%	30.0%	75.0%
AEPSC9	100.5%	91.3%	85.0%	100.0%	30.0%	75.0%
AEPSC169	100.4%	72.1%	85.0%	100.0%	30.0%	75.0%
AEPSC39	100.4%	72.8%	85.0%	100.0%	30.0%	75.0%
AEPSC271	100.4%	87.3%	85.0%	100.0%	30.0%	75.0%
AEPSC167	100.2%	66.2%	85.0%	100.0%	30.0%	75.0%
AEPSC351	100.2%	91.1%	85.0%	100.0%	30.0%	75.0%
AEPSC330	100.1%	91.0%	85.0%	100.0%	30.0%	75.0%
AEPSC175	99.8%	90.7%	85.0%	100.0%	30.0%	75.0%
AEPSC135	99.7%	90.6%	85.0%	100.0%	30.0%	75.0%
AEPSC305	99.5%	86.6%	85.0%	100.0%	30.0%	75.0%
AEPSC196	99.5%	86.5%	85.0%	100.0%	30.0%	75.0%
AEPSC36	99.4%	90.3%	85.0%	100.0%	30.0%	75.0%



AEPSC259	99.3%	91.1%	85.0%	100.0%	30.0%	75.0%
AEPSC112	99.1%	71.9%	85.0%	100.0%	30.0%	75.0%
AEPSC284	99.1%	72.0%	85.0%	100.0%	30.0%	75.0%
AEPSC210	99.1%	71.9%	85.0%	100.0%	30.0%	75.0%
AEPSC237	99.0%	65.7%	85.0%	100.0%	30.0%	75.0%
AEPSC397	98.9%	89.9%	85.0%	100.0%	30.0%	75.0%
AEPSC128	98.9%	89.9%	85.0%	100.0%	30.0%	75.0%
AEPSC444	98.8%	89.8%	85.0%	100.0%	30.0%	75.0%
AEPSC365	98.7%	91.4%	85.0%	100.0%	30.0%	75.0%
AEPSC230	98.6%	85.8%	85.0%	100.0%	30.0%	75.0%
AEPSC250	98.6%	89.6%	85.0%	100.0%	30.0%	75.0%
AEPSC311	98.6%	89.6%	85.0%	100.0%	30.0%	75.0%
AEPSC208	98.5%	90.4%	85.0%	100.0%	30.0%	75.0%
KPCO21	98.3%	85.5%	85.0%	100.0%	30.0%	75.0%
AEPSC448	98.3%	89.3%	85.0%	100.0%	30.0%	75.0%
AEPSC354	98.3%	89.3%	85.0%	100.0%	30.0%	75.0%
AEPSC316	98.2%	85.4%	85.0%	100.0%	30.0%	75.0%
AEPSC275	98.2%	89.3%	85.0%	100.0%	30.0%	75.0%
AEPSC12	98.1%	89.1%	85.0%	100.0%	30.0%	75.0%
AEPSC174	98.0%	92.5%	85.0%	100.0%	30.0%	75.0%
KPCO42	97.7%	70.5%	85.0%	100.0%	30.0%	75.0%
AEPSC100	97.7%	78.6%	85.0%	100.0%	30.0%	75.0%
AEPSC8	97.7%	84.9%	85.0%	100.0%	30.0%	75.0%
AEPSC7	97.7%	90.4%	85.0%	100.0%	30.0%	75.0%
AEPSC312	97.6%	84.9%	85.0%	100.0%	30.0%	75.0%
AEPSC429	97.6%	84.9%	85.0%	100.0%	30.0%	75.0%
AEPSC20	97.6%	88.7%	85.0%	100.0%	30.0%	75.0%
AEPSC121	97.6%	88.7%	85.0%	100.0%	30.0%	75.0%
AEPSC86	97.5%	70.5%	85.0%	100.0%	30.0%	75.0%
AEPSC451	97.5%	84.8%	85.0%	100.0%	30.0%	75.0%
AEPSC466	97.5%	89.4%	85.0%	100.0%	30.0%	75.0%
AEPSC322	97.4%	70.3%	85.0%	100.0%	30.0%	75.0%
AEPSC95	97.4%	88.5%	85.0%	100.0%	30.0%	75.0%
AEPSC164	97.3%	84.6%	85.0%	100.0%	30.0%	75.0%
AEPSC455	97.3%	84.6%	85.0%	100.0%	30.0%	75.0%
AEPSC416	97.3%	89.2%	85.0%	100.0%	30.0%	75.0%
AEPSC232	97.3%	89.2%	85.0%	100.0%	30.0%	75.0%
AEPSC287	97.1%	70.0%	85.0%	100.0%	30.0%	75.0%
AEPSC96	97.1%	70.0%	85.0%	100.0%	30.0%	75.0%
AEPSC430	97.1%	88.2%	85.0%	100.0%	30.0%	75.0%
AEPSC203	97.1%	84.4%	85.0%	100.0%	30.0%	75.0%
AEPSC345	97.0%	89.8%	85.0%	100.0%	30.0%	75.0%
AEPSC41	96.9%	70.8%	85.0%	100.0%	30.0%	75.0%
AEPSC385	96.9%	84.3%	85.0%	100.0%	30.0%	75.0%
AEPSC163	96.8%	89.7%	85.0%	100.0%	30.0%	75.0%
AEPSC151	96.8%	88.0%	85.0%	100.0%	30.0%	75.0%
AEPSC272	96.8%	77.6%	85.0%	100.0%	30.0%	75.0%
KPCO7	96.8%	89.6%	85.0%	100.0%	30.0%	75.0%
AEPSC129	96.8%	88.0%	85.0%	100.0%	30.0%	75.0%
AEPSC138	96.7%	88.0%	85.0%	100.0%	30.0%	75.0%
AEPSC249	96.6%	87.9%	85.0%	100.0%	30.0%	75.0%
AEPSC412	96.6%	88.6%	85.0%	100.0%	30.0%	75.0%

AEPSC223	96.6%	84.0%	85.0%	100.0%	30.0%	75.0%
AEPSC31	96.5%	77.4%	85.0%	100.0%	30.0%	75.0%
AEPSC337	96.5%	89.4%	85.0%	100.0%	30.0%	75.0%
AEPSC148	96.5%	89.4%	85.0%	100.0%	30.0%	75.0%
AEPSC195	96.4%	87.6%	85.0%	100.0%	30.0%	75.0%
AEPSC264	96.4%	83.8%	85.0%	100.0%	30.0%	75.0%
AEPSC309	96.4%	90.9%	85.0%	100.0%	30.0%	75.0%
AEPSC40	96.3%	87.6%	85.0%	100.0%	30.0%	75.0%
AEPSC463	96.3%	69.0%	85.0%	100.0%	30.0%	75.0%
AEPSC258	96.2%	89.1%	85.0%	100.0%	30.0%	75.0%
AEPSC357	96.1%	87.4%	85.0%	100.0%	30.0%	75.0%
AEPSC16	96.1%	88.1%	85.0%	100.0%	30.0%	75.0%
AEPSC234	96.0%	88.1%	85.0%	100.0%	30.0%	75.0%
AEPSC362	96.0%	87.3%	85.0%	100.0%	30.0%	75.0%
AEPSC155	95.9%	77.1%	85.0%	100.0%	30.0%	75.0%
AEPSC11	95.9%	83.4%	85.0%	100.0%	30.0%	75.0%
AEPSC114	95.8%	83.3%	85.0%	100.0%	30.0%	75.0%
AEPSC228	95.8%	87.1%	85.0%	100.0%	30.0%	75.0%
AEPSC265	95.8%	87.9%	85.0%	100.0%	30.0%	75.0%
AEPSC123	95.7%	87.0%	85.0%	100.0%	30.0%	75.0%
AEPSC253	95.5%	88.5%	85.0%	100.0%	30.0%	75.0%
AEPSC457	95.5%	83.1%	85.0%	100.0%	30.0%	75.0%
AEPSC418	95.5%	88.4%	85.0%	100.0%	30.0%	75.0%
AEPSC398	95.4%	82.9%	85.0%	100.0%	30.0%	75.0%
AEPSC101	95.2%	87.3%	85.0%	100.0%	30.0%	75.0%
AEPSC156	95.1%	76.6%	85.0%	100.0%	30.0%	75.0%
AEPSC408	95.1%	86.5%	85.0%	100.0%	30.0%	75.0%
AEPSC395	95.0%	86.4%	85.0%	100.0%	30.0%	75.0%
AEPSC180	95.0%	86.4%	85.0%	100.0%	30.0%	75.0%
KPCO36	94.9%	86.2%	85.0%	100.0%	30.0%	75.0%
AEPSC122	94.8%	82.4%	85.0%	100.0%	30.0%	75.0%
AEPSC220	94.8%	62.6%	85.0%	100.0%	30.0%	75.0%
KPCO19	94.7%	86.1%	85.0%	100.0%	30.0%	75.0%
KPCO40	94.6%	87.6%	85.0%	100.0%	30.0%	75.0%
AEPSC152	94.6%	76.0%	85.0%	100.0%	30.0%	75.0%
KPCO1	94.6%	86.8%	85.0%	100.0%	30.0%	75.0%
AEPSC399	94.6%	86.0%	85.0%	100.0%	30.0%	75.0%
AEPSC468	94.6%	86.0%	85.0%	100.0%	30.0%	75.0%
AEPSC343	94.5%	86.7%	85.0%	100.0%	30.0%	75.0%
AEPSC226	94.4%	85.8%	85.0%	100.0%	30.0%	75.0%
AEPSC66	94.3%	85.7%	85.0%	100.0%	30.0%	75.0%
AEPSC72	94.2%	85.7%	85.0%	100.0%	30.0%	75.0%
AEPSC303	94.2%	75.6%	85.0%	100.0%	30.0%	75.0%
AEPSC263	94.2%	85.6%	85.0%	100.0%	30.0%	75.0%
AEPSC244	94.1%	85.6%	85.0%	100.0%	30.0%	75.0%
AEPSC331	93.9%	85.4%	85.0%	100.0%	30.0%	75.0%
AEPSC420	93.8%	86.1%	85.0%	100.0%	30.0%	75.0%
AEPSC107	93.8%	85.2%	85.0%	100.0%	30.0%	75.0%
KPCO26	93.7%	86.8%	85.0%	100.0%	30.0%	75.0%
AEPSC132	93.7%	81.5%	85.0%	100.0%	30.0%	75.0%
AEPSC427	93.6%	81.4%	85.0%	100.0%	30.0%	75.0%
AEPSC367	93.5%	81.3%	85.0%	100.0%	30.0%	75.0%

AEPSC396	93.5%	85.0%	85.0%	100.0%	30.0%	75.0%
AEPSC19	93.5%	81.3%	85.0%	100.0%	30.0%	75.0%
AEPSC55	93.2%	81.1%	85.0%	100.0%	30.0%	75.0%
AEPSC238	93.2%	74.9%	85.0%	100.0%	30.0%	75.0%
AEPSC462	93.2%	74.8%	85.0%	100.0%	30.0%	75.0%
KPCO33	93.2%	84.7%	85.0%	100.0%	30.0%	75.0%
AEPSC116	93.2%	81.0%	85.0%	100.0%	30.0%	75.0%
AEPSC320	93.1%	81.0%	85.0%	100.0%	30.0%	75.0%
AEPSC456	93.1%	84.6%	85.0%	100.0%	30.0%	75.0%
AEPSC23	93.1%	84.6%	85.0%	100.0%	30.0%	75.0%
KPCO2	93.1%	80.9%	85.0%	100.0%	30.0%	75.0%
AEPSC447	93.0%	80.9%	85.0%	100.0%	30.0%	75.0%
AEPSC419	93.0%	85.4%	85.0%	100.0%	30.0%	75.0%
AEPSC325	93.0%	84.5%	85.0%	100.0%	30.0%	75.0%
AEPSC145	93.0%	85.3%	85.0%	100.0%	30.0%	75.0%
AEPSC347	92.9%	85.2%	85.0%	100.0%	30.0%	75.0%
AEPSC15	92.9%	84.4%	85.0%	100.0%	30.0%	75.0%
AEPSC187	92.8%	85.2%	85.0%	100.0%	30.0%	75.0%
AEPSC449	92.8%	74.7%	85.0%	100.0%	30.0%	75.0%
AEPSC140	92.7%	80.6%	85.0%	100.0%	30.0%	75.0%
AEPSC299	92.7%	80.6%	85.0%	100.0%	30.0%	75.0%
AEPSC144	92.6%	80.5%	85.0%	100.0%	30.0%	75.0%
AEPSC319	92.5%	84.9%	85.0%	100.0%	30.0%	75.0%
AEPSC222	92.5%	74.5%	85.0%	100.0%	30.0%	75.0%
AEPSC199	92.5%	80.4%	85.0%	100.0%	30.0%	75.0%
AEPSC1	92.3%	84.7%	85.0%	100.0%	30.0%	75.0%
KPCO31	92.2%	83.9%	85.0%	100.0%	30.0%	75.0%
AEPSC130	92.2%	83.8%	85.0%	100.0%	30.0%	75.0%
AEPSC380	92.2%	84.6%	85.0%	100.0%	30.0%	75.0%
AEPSC188	92.1%	86.9%	85.0%	100.0%	30.0%	75.0%
AEPSC28	92.1%	83.7%	85.0%	100.0%	30.0%	75.0%
AEPSC4	92.1%	73.8%	85.0%	100.0%	30.0%	75.0%
AEPSC225	92.1%	83.7%	85.0%	100.0%	30.0%	75.0%
AEPSC75	92.0%	85.2%	85.0%	100.0%	30.0%	75.0%
AEPSC336	91.9%	84.3%	85.0%	100.0%	30.0%	75.0%
AEPSC273	91.9%	86.7%	85.0%	100.0%	30.0%	75.0%
AEPSC178	91.9%	79.9%	85.0%	100.0%	30.0%	75.0%
AEPSC2	91.8%	85.0%	85.0%	100.0%	30.0%	75.0%
AEPSC154	91.8%	85.0%	85.0%	100.0%	30.0%	75.0%
AEPSC231	91.7%	83.4%	85.0%	100.0%	30.0%	75.0%
AEPSC227	91.6%	73.7%	85.0%	100.0%	30.0%	75.0%
AEPSC6	91.5%	83.9%	85.0%	100.0%	30.0%	75.0%
KPCO47	91.3%	83.8%	85.0%	100.0%	30.0%	75.0%
AEPSC200	91.3%	83.0%	85.0%	100.0%	30.0%	75.0%
AEPSC439	91.2%	82.9%	85.0%	100.0%	30.0%	75.0%
AEPSC213	91.1%	82.9%	85.0%	100.0%	30.0%	75.0%
AEPSC450	91.1%	82.8%	85.0%	100.0%	30.0%	75.0%
AEPSC236	90.9%	79.0%	85.0%	100.0%	30.0%	75.0%
AEPSC109	90.8%	79.0%	85.0%	100.0%	30.0%	75.0%
AEPSC300	90.8%	82.6%	85.0%	100.0%	30.0%	75.0%
AEPSC318	90.8%	82.5%	85.0%	100.0%	30.0%	75.0%
AEPSC302	90.7%	72.9%	85.0%	100.0%	30.0%	75.0%

AEPSC224	90.6%	78.8%	85.0%	100.0%	30.0%	75.0%
AEPSC321	90.6%	82.4%	85.0%	100.0%	30.0%	75.0%
AEPSC84	90.5%	82.3%	85.0%	100.0%	30.0%	75.0%
KPCO46	90.5%	82.3%	85.0%	100.0%	30.0%	75.0%
KPCO44	90.5%	72.8%	85.0%	100.0%	30.0%	75.0%
AEPSC298	90.4%	82.2%	85.0%	100.0%	30.0%	75.0%
KPCO22	90.3%	72.3%	85.0%	100.0%	30.0%	75.0%
AEPSC53	90.2%	82.0%	85.0%	100.0%	30.0%	75.0%
AEPSC61	90.2%	78.4%	85.0%	100.0%	30.0%	75.0%
AEPSC358	90.1%	78.4%	85.0%	100.0%	30.0%	75.0%
AEPSC179	90.1%	78.3%	85.0%	100.0%	30.0%	75.0%
KPCO45	90.1%	81.9%	85.0%	100.0%	30.0%	75.0%
AEPSC369	90.0%	72.4%	85.0%	100.0%	30.0%	75.0%
AEPSC217	90.0%	82.6%	85.0%	100.0%	30.0%	75.0%
AEPSC323	89.9%	72.1%	85.0%	100.0%	30.0%	75.0%
AEPSC390	89.9%	82.5%	85.0%	100.0%	30.0%	75.0%
AEPSC414	89.9%	81.7%	85.0%	100.0%	30.0%	75.0%
AEPSC473	89.9%	83.2%	85.0%	100.0%	30.0%	75.0%
AEPSC461	89.7%	64.3%	85.0%	100.0%	30.0%	75.0%
AEPSC32	89.7%	78.0%	85.0%	100.0%	30.0%	75.0%
AEPSC160	89.7%	58.7%	85.0%	100.0%	30.0%	75.0%
AEPSC261	89.6%	77.9%	85.0%	100.0%	30.0%	75.0%
AEPSC252	89.6%	81.5%	85.0%	100.0%	30.0%	75.0%
AEPSC137	89.6%	81.4%	85.0%	100.0%	30.0%	75.0%
AEPSC157	89.5%	71.9%	85.0%	100.0%	30.0%	75.0%
AEPSC341	89.4%	81.2%	85.0%	100.0%	30.0%	75.0%
AEPSC54	89.3%	77.6%	85.0%	100.0%	30.0%	75.0%
AEPSC173	89.2%	81.1%	85.0%	100.0%	30.0%	75.0%
AEPSC334	89.1%	71.5%	85.0%	100.0%	30.0%	75.0%
KPCO27	89.1%	84.0%	85.0%	100.0%	30.0%	75.0%
AEPSC340	89.1%	81.0%	85.0%	100.0%	30.0%	75.0%
AEPSC71	89.0%	71.3%	85.0%	100.0%	30.0%	75.0%
AEPSC5	89.0%	77.4%	85.0%	100.0%	30.0%	75.0%
KPCO13	88.9%	81.6%	85.0%	100.0%	30.0%	75.0%
AEPSC417	88.9%	80.9%	85.0%	100.0%	30.0%	75.0%
KPCO12	88.8%	77.3%	85.0%	100.0%	30.0%	75.0%
AEPSC142	88.8%	77.3%	85.0%	100.0%	30.0%	75.0%
AEPSC286	88.8%	64.4%	85.0%	100.0%	30.0%	75.0%
AEPSC409	88.8%	80.7%	85.0%	100.0%	30.0%	75.0%
AEPSC65	88.7%	80.7%	85.0%	100.0%	30.0%	75.0%
AEPSC307	88.7%	80.6%	85.0%	100.0%	30.0%	75.0%
AEPSC214	88.6%	80.5%	85.0%	100.0%	30.0%	75.0%
AEPSC256	88.6%	80.5%	85.0%	100.0%	30.0%	75.0%
AEPSC342	88.4%	80.3%	85.0%	100.0%	30.0%	75.0%
AEPSC310	88.3%	80.3%	85.0%	100.0%	30.0%	75.0%
AEPSC338	88.2%	80.2%	85.0%	100.0%	30.0%	75.0%
AEPSC103	88.2%	80.2%	85.0%	100.0%	30.0%	75.0%
AEPSC277	88.2%	76.7%	85.0%	100.0%	30.0%	75.0%
AEPSC81	88.1%	81.6%	85.0%	100.0%	30.0%	75.0%
AEPSC454	87.7%	79.8%	85.0%	100.0%	30.0%	75.0%
AEPSC295	87.7%	70.8%	85.0%	100.0%	30.0%	75.0%
AEPSC211	87.7%	58.4%	85.0%	100.0%	30.0%	75.0%

AEPSC209	87.6%	79.6%	85.0%	100.0%	30.0%	75.0%
AEPSC87	87.6%	76.2%	85.0%	100.0%	30.0%	75.0%
AEPSC251	87.6%	63.4%	85.0%	100.0%	30.0%	75.0%
KPCO9	87.5%	79.6%	85.0%	100.0%	30.0%	75.0%
AEPSC469	87.5%	79.6%	85.0%	100.0%	30.0%	75.0%
AEPSC313	87.4%	79.5%	85.0%	100.0%	30.0%	75.0%
AEPSC105	87.3%	70.3%	85.0%	100.0%	30.0%	75.0%
AEPSC115	87.3%	63.2%	85.0%	100.0%	30.0%	75.0%
AEPSC394	87.3%	79.3%	85.0%	100.0%	30.0%	75.0%
AEPSC67	87.1%	75.8%	85.0%	100.0%	30.0%	75.0%
AEPSC204	87.1%	79.1%	85.0%	100.0%	30.0%	75.0%
AEPSC384	86.9%	79.0%	85.0%	100.0%	30.0%	75.0%
KPCO37	86.8%	78.9%	85.0%	100.0%	30.0%	75.0%
AEPSC17	86.8%	69.9%	85.0%	100.0%	30.0%	75.0%
AEPSC382	86.7%	78.9%	85.0%	100.0%	30.0%	75.0%
AEPSC441	86.7%	75.4%	85.0%	100.0%	30.0%	75.0%
KPCO8	86.6%	79.5%	85.0%	100.0%	30.0%	75.0%
AEPSC74	86.6%	81.7%	85.0%	100.0%	30.0%	75.0%
AEPSC85	86.6%	69.8%	85.0%	100.0%	30.0%	75.0%
AEPSC126	86.6%	80.2%	85.0%	100.0%	30.0%	75.0%
AEPSC124	86.6%	78.7%	85.0%	100.0%	30.0%	75.0%
AEPSC56	86.6%	79.4%	85.0%	100.0%	30.0%	75.0%
AEPSC364	86.4%	75.2%	85.0%	100.0%	30.0%	75.0%
AEPSC401	86.4%	80.0%	85.0%	100.0%	30.0%	75.0%
AEPSC216	86.4%	78.5%	85.0%	100.0%	30.0%	75.0%
AEPSC73	86.3%	78.5%	85.0%	100.0%	30.0%	75.0%
AEPSC386	86.3%	78.4%	85.0%	100.0%	30.0%	75.0%
AEPSC33	86.2%	78.4%	85.0%	100.0%	30.0%	75.0%
AEPSC43	86.2%	78.4%	85.0%	100.0%	30.0%	75.0%
AEPSC404	86.1%	69.0%	85.0%	100.0%	30.0%	75.0%
AEPSC18	85.9%	78.1%	85.0%	100.0%	30.0%	75.0%
AEPSC108	85.8%	78.0%	85.0%	100.0%	30.0%	75.0%
AEPSC185	85.8%	78.0%	85.0%	100.0%	30.0%	75.0%
AEPSC207	85.6%	77.8%	85.0%	100.0%	30.0%	75.0%
AEPSC50	85.5%	77.8%	85.0%	100.0%	30.0%	75.0%
AEPSC428	85.4%	77.7%	85.0%	100.0%	30.0%	75.0%
KPCO35	85.1%	77.4%	85.0%	100.0%	30.0%	75.0%
AEPSC190	85.1%	74.0%	85.0%	100.0%	30.0%	75.0%
KPCO28	85.0%	73.9%	85.0%	100.0%	30.0%	75.0%
AEPSC422	85.0%	77.3%	85.0%	100.0%	30.0%	75.0%
KPCO23	84.8%	77.1%	85.0%	100.0%	30.0%	75.0%
AEPSC443	84.8%	77.1%	85.0%	100.0%	30.0%	75.0%
AEPSC474	84.7%	79.9%	85.0%	100.0%	30.0%	75.0%
AEPSC27	84.6%	76.9%	85.0%	100.0%	30.0%	75.0%
AEPSC255	84.5%	77.5%	85.0%	100.0%	30.0%	75.0%
AEPSC314	84.4%	76.8%	85.0%	100.0%	30.0%	75.0%
AEPSC76	84.3%	77.3%	85.0%	100.0%	30.0%	75.0%
KPCO10	84.0%	67.5%	85.0%	100.0%	30.0%	75.0%
KPCO25	83.9%	77.0%	85.0%	100.0%	30.0%	75.0%
AEPSC64	83.9%	76.3%	85.0%	100.0%	30.0%	75.0%
AEPSC339	83.8%	72.8%	85.0%	100.0%	30.0%	75.0%
AEPSC99	83.8%	76.2%	85.0%	100.0%	30.0%	75.0%

AEPSC383	83.6%	76.0%	85.0%	100.0%	30.0%	75.0%
AEPSC113	83.5%	72.7%	85.0%	100.0%	30.0%	75.0%
AEPSC98	83.5%	75.9%	85.0%	100.0%	30.0%	75.0%
AEPSC465	83.5%	75.9%	85.0%	100.0%	30.0%	75.0%
AEPSC315	83.4%	76.6%	85.0%	100.0%	30.0%	75.0%
AEPSC476	83.3%	76.4%	85.0%	100.0%	30.0%	75.0%
AEPSC162	83.1%	75.5%	85.0%	100.0%	30.0%	75.0%
AEPSC296	83.0%	66.8%	85.0%	100.0%	30.0%	75.0%
AEPSC470	82.8%	72.0%	85.0%	100.0%	30.0%	75.0%
AEPSC127	82.7%	75.9%	85.0%	100.0%	30.0%	75.0%
AEPSC356	82.7%	76.6%	85.0%	100.0%	30.0%	75.0%
AEPSC260	82.6%	75.1%	85.0%	100.0%	30.0%	75.0%
KPCO34	82.3%	71.5%	85.0%	100.0%	30.0%	75.0%
AEPSC111	81.8%	74.4%	85.0%	100.0%	30.0%	75.0%
AEPSC359	81.8%	74.3%	85.0%	100.0%	30.0%	75.0%
KPCO41	81.6%	75.6%	85.0%	100.0%	30.0%	75.0%
AEPSC459	81.4%	65.4%	85.0%	100.0%	30.0%	75.0%
AEPSC78	81.1%	73.8%	85.0%	100.0%	30.0%	75.0%
AEPSC475	81.0%	73.7%	85.0%	100.0%	30.0%	75.0%
KPCO14	80.8%	73.4%	85.0%	100.0%	30.0%	75.0%
AEPSC44	80.7%	73.4%	85.0%	100.0%	30.0%	75.0%
AEPSC400	80.6%	74.0%	85.0%	100.0%	30.0%	75.0%
AEPSC432	80.6%	64.8%	85.0%	100.0%	30.0%	75.0%
AEPSC471	80.4%	64.6%	85.0%	100.0%	30.0%	75.0%
AEPSC37	80.2%	72.9%	85.0%	100.0%	30.0%	75.0%
KPCO24	80.1%	72.8%	85.0%	100.0%	30.0%	75.0%
AEPSC453	79.9%	64.2%	85.0%	100.0%	30.0%	75.0%
AEPSC335	79.7%	72.5%	85.0%	100.0%	30.0%	75.0%
AEPSC413	79.1%	71.9%	85.0%	100.0%	30.0%	75.0%
AEPSC458	79.1%	63.5%	85.0%	100.0%	30.0%	75.0%
AEPSC392	78.9%	72.4%	85.0%	100.0%	30.0%	75.0%
AEPSC134	78.9%	71.7%	85.0%	100.0%	30.0%	75.0%
AEPSC433	78.7%	63.3%	85.0%	100.0%	30.0%	75.0%
AEPSC83	78.6%	71.4%	85.0%	100.0%	30.0%	75.0%
AEPSC434	78.5%	63.0%	85.0%	100.0%	30.0%	75.0%
AEPSC38	78.4%	68.1%	85.0%	100.0%	30.0%	75.0%
KPCO49	78.0%	73.6%	85.0%	100.0%	30.0%	75.0%
KPCO18	78.0%	70.9%	85.0%	100.0%	30.0%	75.0%
KPCO39	77.8%	72.4%	85.0%	100.0%	30.0%	75.0%
AEPSC460	76.7%	61.5%	85.0%	100.0%	30.0%	75.0%
AEPSC125	76.4%	69.4%	85.0%	100.0%	30.0%	75.0%
AEPSC13	76.3%	69.3%	85.0%	100.0%	30.0%	75.0%
AEPSC60	75.7%	68.8%	85.0%	100.0%	30.0%	75.0%
AEPSC58	75.6%	68.7%	85.0%	100.0%	30.0%	75.0%
AEPSC176	75.5%	68.6%	85.0%	100.0%	30.0%	75.0%
AEPSC30	75.4%	60.6%	85.0%	100.0%	30.0%	75.0%
AEPSC376	75.3%	43.6%	85.0%	100.0%	30.0%	75.0%
AEPSC48	75.1%	68.3%	85.0%	100.0%	30.0%	75.0%
AEPSC266	74.9%	68.1%	85.0%	100.0%	30.0%	75.0%
AEPSC59	74.6%	64.9%	85.0%	100.0%	30.0%	75.0%
KPCO15	74.4%	67.6%	85.0%	100.0%	30.0%	75.0%
AEPSC391	74.0%	67.9%	85.0%	100.0%	30.0%	75.0%

KPCO38	73.2%	68.4%	85.0%	100.0%	30.0%	75.0%
AEPSC147	72.4%	66.4%	85.0%	100.0%	30.0%	75.0%
AEPSC57	72.0%	65.5%	85.0%	100.0%	30.0%	75.0%
AEPSC219	71.6%	47.3%	85.0%	100.0%	30.0%	75.0%
AEPSC149	71.5%	66.2%	85.0%	100.0%	30.0%	75.0%
AEPSC106	71.0%	61.7%	85.0%	100.0%	30.0%	75.0%
AEPSC373	69.5%	40.7%	85.0%	100.0%	30.0%	75.0%
AEPSC372	69.0%	40.3%	85.0%	100.0%	30.0%	75.0%
AEPSC170	68.6%	63.5%	85.0%	100.0%	30.0%	75.0%
AEPSC403	67.0%	60.9%	85.0%	100.0%	30.0%	75.0%
AEPSC375	60.3%	39.5%	85.0%	100.0%	30.0%	75.0%
AEPSC88	44.6%	29.6%	85.0%	100.0%	30.0%	75.0%

KPCO and AEPSC Compensation for Officer Positions Versus Market Competitive Compensation

		Incumbent Data						Market Median Survey Results <sup>1</sup>					% Difference		
		Incumbent Count	Actual or Avg. Base Salary	Target Incentive	Target Total Cash Compensation (TCC)	Long-Term Incentive (LTI)	Target Total Compensation (TC)	Base Salary	Target Incentive	Target TCC	LTI	Target TC	Target TC vs Survey Target TC <sup>3</sup>	Target TCC vs Survey Target TC <sup>3</sup>	Base Salary vs Survey TC <sup>3</sup>
Job Identifier <sup>2</sup>															
EX1	1	\$ 342,990	\$ 205,794	\$ 548,784	\$ 300,000	\$848,784	\$ 359,163	\$ 183,639	\$ 542,802	\$ 272,923	\$ 815,725	4.1%	-32.7%	-58.0%	
EX2	1	\$ 184,886	\$ 46,221	\$ 231,107	\$ 25,000	\$256,107	\$ 177,514	\$ 15,257	\$ 192,771	\$ 20,163	\$ 212,934	20.3%	8.5%	-13.2%	
EX3	1	\$ 268,452	\$ 93,958	\$ 362,410	\$ 93,000	\$ 455,410	\$ 217,435	\$ 33,175	\$ 250,610	\$ 16,558	\$ 267,168	70.5%	35.6%	0.5%	
EX4	1	\$ 267,105	\$ 93,487	\$ 360,591	\$ 93,000	\$ 453,591	\$ 283,890	\$ 85,167	\$ 369,057	\$ 125,922	\$ 494,979	-8.4%	-27.2%	-46.0%	
EX5	2	\$ 293,825	\$ 117,530	\$ 411,355	\$ 147,000	\$ 558,355	\$ 286,187	\$ 127,796	\$ 413,983	\$ 167,522	\$ 581,505	-4.0%	-29.3%	-49.5%	
EX6	1	\$ 291,500	\$ 102,025	\$ 393,525	\$ 93,000	\$ 486,525	\$ 287,172	\$ 104,488	\$ 391,660	\$ 136,381	\$ 528,041	-7.9%	-25.5%	-44.8%	
EX7	1	\$ 310,000	\$ 108,500	\$ 418,500	\$ 93,000	\$ 511,500	\$ 296,268	\$ 130,213	\$ 426,481	\$ 156,088	\$ 582,569	-12.2%	-28.2%	-46.8%	
EX8	1	\$ 327,827	\$ 131,131	\$ 458,958	\$ 147,000	\$ 605,958	\$ 327,916	\$ 117,136	\$ 445,052	\$ 148,947	\$ 593,999	2.0%	-22.7%	-44.8%	
EX9	1	\$ 295,000	\$ 118,000	\$ 413,000	\$ 147,000	\$ 560,000	\$ 327,934	\$ 122,681	\$ 450,615	\$ 157,663	\$ 608,278	-7.9%	-32.1%	-51.5%	
EX10	1	\$ 325,000	\$ 146,250	\$ 471,250	\$ 266,500	\$ 737,750	\$ 331,554	\$ 150,425	\$ 481,979	\$ 223,684	\$ 705,663	4.5%	-33.2%	-53.9%	
EX11	1	\$ 411,066	\$ 205,533	\$ 616,599	\$ 344,000	\$ 960,599	\$ 342,145	\$ 130,419	\$ 472,563	\$ 263,429	\$ 735,993	30.5%	-16.2%	-44.1%	
EX12	1	\$ 317,785	\$ 127,114	\$ 444,898	\$ 147,000	\$ 591,898	\$ 343,425	\$ 137,338	\$ 480,763	\$ 157,704	\$ 638,467	-7.3%	-30.3%	-50.2%	
EX13	1	\$ 401,750	\$ 180,788	\$ 582,538	\$ 266,500	\$ 849,038	\$ 343,712	\$ 162,122	\$ 505,834	\$ 101,445	\$ 607,279	39.8%	-4.1%	-33.8%	
EX14	1	\$ 288,500	\$ 100,975	\$ 389,475	\$ 93,000	\$ 482,475	\$ 345,036	\$ 160,108	\$ 505,144	\$ 190,448	\$ 695,592	-30.6%	-44.0%	-58.5%	
EX15	1	\$ 346,725	\$ 138,690	\$ 485,415	\$ 147,000	\$ 632,415	\$ 353,330	\$ 150,349	\$ 503,679	\$ 223,666	\$ 727,345	-13.1%	-33.3%	-52.3%	
EX16	1	\$ 390,000	\$ 195,000	\$ 585,000	\$ 400,000	\$ 985,000	\$ 356,900	\$ 158,900	\$ 515,800	\$ 197,100	\$ 712,900	38.2%	-17.9%	-45.3%	
EX17	1	\$ 368,991	\$ 166,046	\$ 535,037	\$ 266,500	\$ 801,537	\$ 373,345	\$ 153,731	\$ 527,076	\$ 224,296	\$ 751,372	6.7%	-28.8%	-50.9%	
EX18	1	\$ 339,900	\$ 135,960	\$ 475,860	\$ 180,000	\$ 655,860	\$ 382,346	\$ 166,926	\$ 549,272	\$ 183,368	\$ 732,640	-10.5%	-35.0%	-53.6%	
EX19	1	\$ 477,140	\$ 238,570	\$ 715,710	\$ 344,000	\$ 1,059,710	\$ 397,915	\$ 168,550	\$ 566,465	\$ 270,575	\$ 837,040	26.6%	-14.5%	-43.0%	
EX20	1	\$ 430,904	\$ 193,907	\$ 624,811	\$ 400,000	\$ 1,024,811	\$ 410,110	\$ 204,437	\$ 614,547	\$ 295,697	\$ 910,244	12.6%	-31.4%	-52.7%	
EX21	1	\$ 360,500	\$ 162,225	\$ 522,725	\$ 266,500	\$ 789,225	\$ 437,300	\$ 212,500	\$ 649,800	\$ 272,600	\$ 922,400	-14.4%	-43.3%	-60.9%	
EX22 <sup>4</sup>	1	\$ 510,640	\$ 306,384	\$ 817,024	\$ 475,000	\$ 1,292,024	\$ 485,392	\$ 249,237	\$ 734,629	\$ 464,143	\$ 1,198,771	7.8%	-31.8%	-57.4%	
EX23	1	\$ 614,663	\$ 460,997	\$ 1,075,659	\$ 1,200,000	\$ 2,275,659	\$ 652,799	\$ 457,932	\$ 1,110,732	\$ 1,311,190	\$ 2,421,922	-6.0%	-55.6%	-74.6%	
EX24	1	\$ 735,000	\$ 588,000	\$ 1,323,000	\$ 1,200,000	\$ 2,523,000	\$ 698,500	\$ 488,950	\$ 1,187,450	\$ 1,210,000	\$ 2,397,450	5.2%	-44.8%	-69.3%	
EX25	1	\$ 975,000	\$ 975,000	\$ 1,950,000	\$ 3,800,000	\$ 5,750,000	\$ 750,000	\$ 663,000	\$ 1,413,000	\$ 2,089,000	\$ 3,502,000	64.2%	-44.3%	-72.2%	
EX26	1	\$ 803,140	\$ 602,355	\$ 1,405,495	\$ 2,100,000	\$ 3,505,495	\$ 764,067	\$ 624,215	\$ 1,388,282	\$ 1,908,853	\$ 3,297,135	6.3%	-57.4%	-75.6%	
EX27	1	\$ 1,500,000	\$ 2,400,000	\$ 3,900,000	\$ 11,100,000	\$ 15,000,000	\$ 1,345,000	\$ 1,875,000	\$ 3,220,000	\$ 9,905,000	\$ 13,125,000	14.3%	-70.3%	-88.6%	
Incumbent Count:	28						Number of Jobs with Significant STI:					8.6%	-29.2%	-51.5%	
Job Count:	27						Number of Jobs without Significant STI:					19%	89%	96%	
							AVERAGE:					33%	4%	0%	
							% of Jobs Below Market Competitive Range <sup>3</sup>					% of Jobs Above Market Competitive Range <sup>3</sup>			

Notes:

<sup>1</sup> Survey Data from the 2024 Willis Towers Watson Energy Services and General Industry Executive Compensation Surveys or, in some cases, Middle Management, Professional & Support surveys, in all cases aged from April 1, 2024 to May 31, 2025 at 3.5% annual rate.

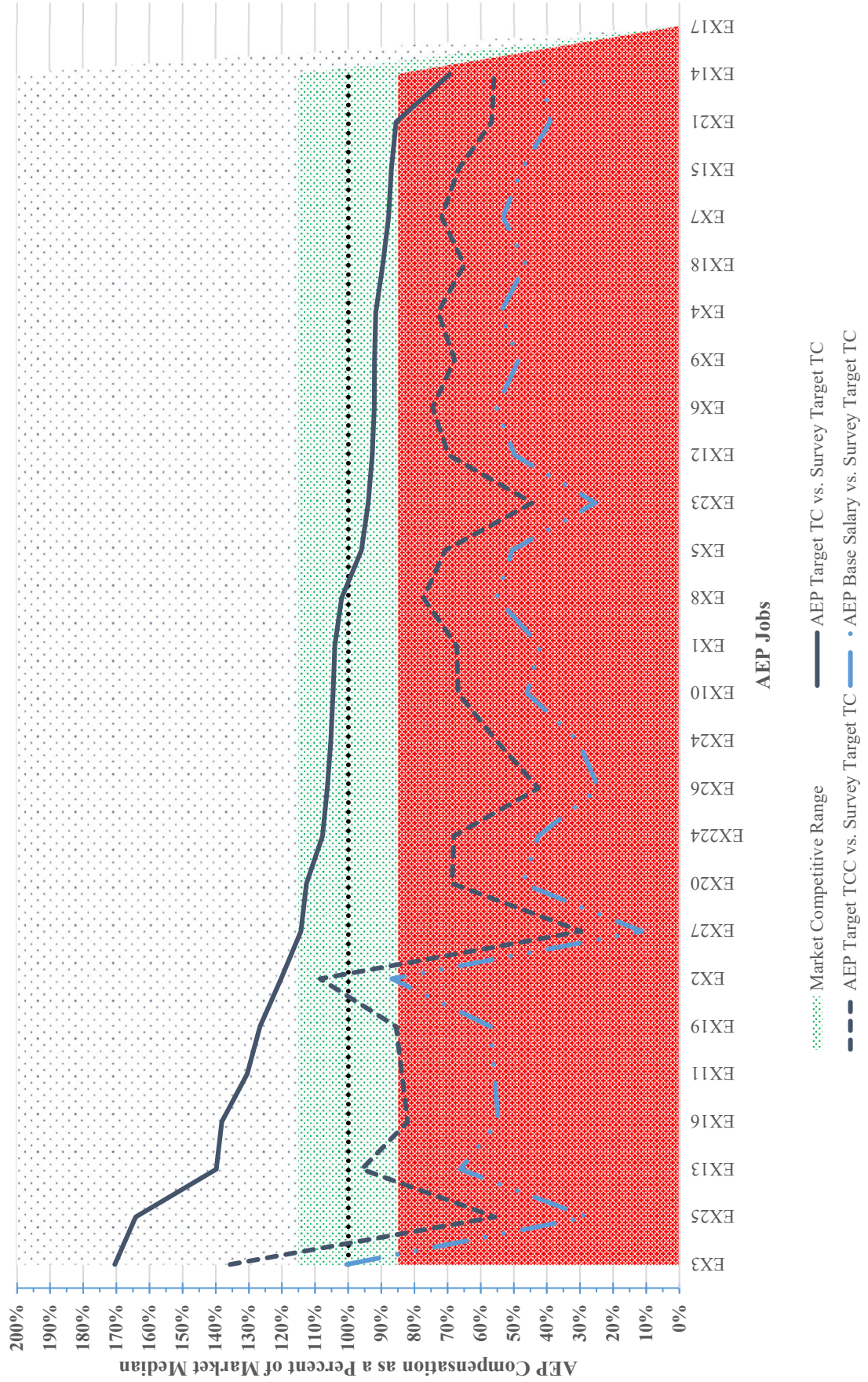
<sup>2</sup> Includes all Kentucky Power Company and AEPSC Officers positions as of May 31, 2025 for which there was a matching survey job with a sufficient sample of compensation survey information.

<sup>3</sup> A market competitive range of +/- 15 percent has been used for these salaried nonexempt positions.

<sup>4</sup> This position is benchmarked against the 75th percentile because this was a competitive hire with skills and experience that Sr. Management and the HR Committee of AEP's Board of Directors believed would bring sufficient additional value to offset the additional expense.



**Figure ARC 9**  
**KPCO and AEPSC Officer Positions**  
**vs. Market-Competitive Compensation (High to Low)**  
**1. With AEP STI & LTI, 2. With AEP STI but not LTI, and 3. without AEP STI and LTI**



<b><u>AEP Job</u></b>	<b>AEP Target TC vs. Survey Target TC</b>	<b>AEP Target TCC vs. Survey Target TC</b>	<b>AEP Base Salary vs. Survey Target TC</b>	<b>Market Low</b>	<b>Market Median Compensation</b>	<b>Market Competitive Range</b>	<b>Market Max</b>
EX3	170.5%	135.6%	100.5%	85.0%	100.0%	30.0%	85.0%
EX25	164.2%	55.7%	27.8%	85.0%	100.0%	30.0%	85.0%
EX13	139.8%	95.9%	66.2%	85.0%	100.0%	30.0%	85.0%
EX16	138.2%	82.1%	54.7%	85.0%	100.0%	30.0%	85.0%
EX11	130.5%	83.8%	55.9%	85.0%	100.0%	30.0%	85.0%
EX19	126.6%	85.5%	57.0%	85.0%	100.0%	30.0%	85.0%
EX2	120.3%	108.5%	86.8%	85.0%	100.0%	30.0%	85.0%
EX27	114.3%	29.7%	11.4%	85.0%	100.0%	30.0%	85.0%
EX20	112.6%	68.6%	47.3%	85.0%	100.0%	30.0%	85.0%
EX22 <sup>4</sup>	107.8%	68.2%	42.6%	85.0%	100.0%	30.0%	85.0%
EX26	106.3%	42.6%	24.4%	85.0%	100.0%	30.0%	85.0%
EX24	105.2%	55.2%	30.7%	85.0%	100.0%	30.0%	85.0%
EX10	104.5%	66.8%	46.1%	85.0%	100.0%	30.0%	85.0%
EX1	104.1%	67.3%	42.0%	85.0%	100.0%	30.0%	85.0%
EX8	102.0%	77.3%	55.2%	85.0%	100.0%	30.0%	85.0%
EX5	96.0%	70.7%	50.5%	85.0%	100.0%	30.0%	85.0%
EX23	94.0%	44.4%	25.4%	85.0%	100.0%	30.0%	85.0%
EX12	92.7%	69.7%	49.8%	85.0%	100.0%	30.0%	85.0%
EX6	92.1%	74.5%	55.2%	85.0%	100.0%	30.0%	85.0%
EX9	92.1%	67.9%	48.5%	85.0%	100.0%	30.0%	85.0%
EX4	91.6%	72.8%	54.0%	85.0%	100.0%	30.0%	85.0%
EX18	89.5%	65.0%	46.4%	85.0%	100.0%	30.0%	85.0%
EX7	87.8%	71.8%	53.2%	85.0%	100.0%	30.0%	85.0%
EX15	86.9%	66.7%	47.7%	85.0%	100.0%	30.0%	85.0%
EX21	85.6%	56.7%	39.1%	85.0%	100.0%	30.0%	85.0%
EX14	69.4%	56.0%	41.5%	85.0%	100.0%	30.0%	85.0%
EX17							


# Kentucky Power Scorecard: Wiseman

KPI		WGHT	2022 Actual	2023 Actual	2024 Actual	2025 Target	2025 Forecast
CUSTOMER SERVICE	• Industry-best customer experience		8.33%	138	144	≤140	
			8.33%	N/A	0.68	≤0.61	
EMPLOYEE COMMITMENT	• Safe & secure workplace • Engaged, trained & developed employees	Total Recordable Incident Rate	4.16%	1,547	1,550	0.794	≤0.715
		DART Rate	4.16%	0.774	1.937	0.794	≤0.715
		Phishing Failure Rate (%)	4.16%	1.96	1.06	1.52	≤1.0
		Engage, Train & Develop	4.16%	N/A	N/A	N/A	Achieve
REGULATORY & LEGISLATIVE INTEGRITY	• Balanced regulatory outcomes • Trusted industry leadership	Achieve Plan ROE (%)	8.33%	5.35	3.71	4.44	≥5.40
		Reduce NOV's (Number of Events)	8.33%	N/A	N/A	0	=0
ENVIRONMENTAL RESPECT	• Creative sustainable solutions	Environmental Respect Index (Number of Events)	16.67%	N/A	N/A	0	=0
OPERATIONAL EXCELLENCE	• World class asset performance	Delivery SAIDI - T&D (Minutes)	8.33%	490.62	331.76	405.85	≤382.00
		EFORd (%)	8.33%	4.17	3.52	1.78	≤1.77
FINANCIAL STRENGTH	• Strong financial discipline	Operating Earnings (\$)	5.56%	48M	35M	43M	≥47M
		O&M Budget (\$)	5.56%	28M	48M	48M	≤48M
		FFO/Debt (%)	5.56%	9.50	5.80	8.84	≥8.70




# AEP Scorecard

## CUSTOMER SERVICE




- Industry-best customer experience

## EMPLOYEE COMMITMENT



- Safe & secure workplace
- Engaged, trained & developed employees

## REGULATORY & LEGISLATIVE INTEGRITY




- Balanced regulatory outcomes
- Trusted industry leadership

## ENVIRONMENTAL RESPECT




- Creative sustainable solutions

## OPERATIONAL EXCELLENCE



- World class asset performance

## FINANCIAL STRENGTH



- Strong financial discipline

KPI	WGHT	2022 Actual	2023 Actual	2024 Actual	2025 Target	2025 Forecast
Customer Satisfaction (JD Power avg rank)	8.33%	88.33	102.67	93.17	89.17	
Perfect Power >= 13 interruptions (%)	8.33%	N/A	N/A	13.19%	<=11.87%	
Total Recordable Incident Rate	4.17%	0.719	0.690	0.913	0.822	
DART Rate	4.17%	0.424	0.384	0.556	0.500	
Safety Improvement Plan & Training	4.17%	N/A	N/A	N/A	Achieve	
Engage, Train & Develop Plan	4.17%	N/A	N/A	N/A	Achieve	
Achieve Plan ROE	16.67%	9.13%	8.78%	9.05%	9.375%	
Environmental Respect Index	16.67%	N/A	N/A	139	123	
Delivery SAIDI (T&D)	8.33%	272.85	219.39	234.19	219.20	
Transmission Reliability Index	8.33%	43.43	50.87	49.01	2.5% Improvement	
Financial Performance Operating EPS	16.67%	5.090	5.250	5.6178	5.90	

**January 1, 2025 - December 31, 2025**

**PARTICIPANT MEDICAL CONTRIBUTIONS**

The pre-tax monthly cost to active full-time employees is calculated based on a percentage of the total cost of coverage. The pre-tax monthly costs to active part-time employees are two and one-half times the monthly costs of active full-time employees.

**MEDICAL PLAN SURCHARGES**

**Spousal Surcharge**

Effective January 1, 2014, if an active employee covers his/her spouse/domestic partner on AEP's medical plan, and that spouse/domestic partner has access to medical coverage through his/her employer, the employee will be assessed a surcharge of \$50.00 per month.

**Tobacco Surcharge**

Effective January 1, 2021, a \$50.00 per month tobacco surcharge applies to spouses or domestic partners enrolled in AEP medical coverage who indicate they use tobacco or nicotine products. This works in conjunction with the rule that was effective January 1, 2015, for employees who use tobacco and nicotine products will have a surcharge, in the amount of \$50.00 per month, assessed when they elect coverage under AEP's medical plan.



January 1, 2025 – December 31, 2025

**GROUP MEDICAL PLANS**

Health Savings Account (HSA) Plan Options	HSA Basic		HSA Plus	
	In-Network	Out-of-Network	In-Network	Out-of-Network
<b>Company Annual Contribution to HSA</b>	NA	NA	participant only: \$500 participant + spouse or participant + child(ren): \$750 participant + family: \$1,000	
<b>Annual Deductible (includes medical, prescription and behavioral health)</b>	\$3,300/participant \$6,000/participant + spouse \$6,000/participant + 1 child \$9,000/participant + children \$9,000/participant + family	\$4,000/participant \$8,000/participant + spouse \$8,000/participant + 1 child \$12,000/participant + children \$12,000/participant + family	\$2,000/participant \$3,300/participant + spouse \$3,300/participant + child(ren) \$4,000/participant + family	\$3,000/participant \$4,500/participant + spouse \$4,500/participant + child(ren) \$6,000/participant + family
<b>Annual out-of-pocket maximum</b>	\$4,000/participant \$8,000/participant + spouse \$8,000/participant + 1 child \$12,000/participant + child(ren) \$12,000/participant + family	\$8,000/participant \$16,000/participant + spouse \$16,000/participant + 1 child \$24,000/participant + child(ren) \$24,000/participant + family	\$4,000/participant \$6,000/participant + spouse \$6,000/participant + child(ren) \$8,000/participant + family	\$6,000/participant \$9,000/participant + spouse \$9,000/participant + child(ren) \$12,000/participant + family
<b>Co-Insurance</b>	10% after deductible	30% after deductible	15% after deductible	30% after deductible
<b>Preventive Care</b>	\$0%; no deductible	30% after deductible	\$0%; no deductible	30% after deductible
<b>Prescription Coverage</b>	10% after deductible		15% after deductible	
<b>2025 Full-Time Employee Monthly Cost</b>	\$40.34 participant only \$147.33 participant + spouse/domestic partner \$119.59 participant + child(ren) \$226.57 participant + family		\$106.80 participant only \$303.49 participant + spouse/domestic partner \$252.49 participant + child(ren) \$449.19 participant + family	

January 1, 2025– December 31, 2025

HRA Plan				
		Participant Only	Participant + Spouse or Participant + Child(ren)	Participant + Family
Health Reimbursement Account (HRA)	AEP Annual Allocation	\$1,000	\$1,500	\$2,000
Traditional Health Coverage (Prescription coverage same as any other medical expense)	Annual Deductible (includes medical, prescription drug and behavioral health)	\$1,500	\$2,250	\$3,000
	Then, employee pays coinsurance for covered services	15% for in-network providers 30% for out-of-network providers		
	Annual Out-of-Pocket Maximum	\$4,000 if in-network \$6,500 if out-of-network	\$6,000 if in-network \$9,750 if out-of-network	\$8,000 if in-network \$13,000 if out-of-network
Annual Preventive (not applied to Company's HRA allocation)	In-network: 0%; no deductible Out-of-network: 30% after deductible			
2025 Full-Time Employee Monthly Cost	\$185.95 participant only \$489.51 participant + spouse/domestic partner \$410.81 participant + child(ren) \$714.36 participant + family			

### Live Health Online

Live Health Online provides employees and their eligible dependents with 24/7/365 access to US board-certified physicians by online video. Live Health Online can diagnose, recommend treatment and prescribe medication when appropriate, including sinus problem, bronchitis, allergies, poison ivy, cold and flu symptoms, urinary tract infection, respiratory infection and more. This program is available to participants enrolled in an AEP health plan.

### Wellness Program

Healthy living habits are an essential ingredient for healthy employees. For that reason, AEP sponsors a number of programs, including incentives, and initiatives designed to help employees achieve and maintain a healthy lifestyle. All active employees (regardless of whether they are enrolled in a medical plan) are eligible to participate in the following wellness programs along with spouses and domestic partners of active employees who are covered under an AEP medical plan. Rewards are offered for annual well check, dental exams, eye exam or skin cancer screening, and financial wellbeing coaching calls, diabetes prevention and weight management programs, and healthy living challenges during the year.

January 1, 2025– December 31, 2025

## **GROUP DENTAL**

### **DPPO option**

Coverage Level	Participant Only	Participant + Spouse	Participant + Child(ren)	Participant + Family
Deductible (not applicable to preventive services)	\$50/individual	\$50/individual	\$50/individual \$150/family	\$150/Family
Annual Maximum	\$1,750 per covered person			
Coinsurance				
Preventive	100%			
Basic Services	80% after deductible			
Major Services	50% after deductible			
Orthodontia	50% up to a lifetime maximum of \$1,750 per covered child (eligible children under age 19)			

### **DMO Option**

A DMO option is available to employees who live within the same zip code area as a network DMO dentist. Similar to a medical Health Maintenance Organization (HMO), the DMO provides dental service through a group of network dentist. The DMO offers no deductibles or annual maximum, no co-pay for covered preventive services and low, fixed co-pays on other dental services.

The pre-tax monthly costs to active part-time employees are two and one-half times the monthly costs to active full-time employees. The monthly costs to certain grandfathered retirees and surviving dependents are the same as active employees. The monthly cost to most other retirees and eligible surviving dependents are 100% of the total cost of coverage.

Employee Monthly Contribution	Employee Only	Employee + Spouse/domestic partner	Employee + Child(ren)	Employee + Family
DPPO Plan	\$12.55	\$26.75	\$40.08	\$54.20
DMO Plan	\$9.37	\$19.93	\$22.56	\$33.11

## **VISION PLAN**

AEP offers comprehensive employee paid vision coverage for eye care and vision correction. AEP's Comprehensive Vision Plan provides coverage through the Fidelity Security Life Insurance Company for eye exams, contacts (including disposable contacts) and eyeglass lenses and frames. It also offers discounts on special features, such as scratch-resistant lenses, laser eye surgery and more.

Vision plan participants can take advantage of the discounted retinal-imaging exam option; in addition, members who have Type 1 or Type 2 diabetes are eligible for a follow-up exam and additional testing two times per benefit year.

Benefits are provided through EyeMed Vision Care's Access national network of private practice optometrists, ophthalmologists, opticians and retailers.

Employee Monthly Contribution	Employee Only	Employee + Spouse	Employee + Child(ren)	Employee + Family
	\$ 6.82	\$12.93	\$13.61	\$20.41



## Employee And Employer Contribution Rates

Full Plan Monthly Rates - Active Employees				
2025	EE Only	EE + Spouse	EE + Child(ren)	EE + Family
HRA	\$778.04	\$1,828.40	\$1,556.09	\$2,606.44
HSA Plus	\$698.89	\$1,642.38	\$1,397.77	\$2,341.27
HSA Basic	\$632.43	\$1,486.22	\$1,264.87	\$2,118.65
Dental PPO	\$31.37	\$62.74	\$92.55	\$123.92
Dental DMO	\$23.43	\$46.89	\$52.73	\$76.17

Full-time Active Employee Contributions				
2025	EE Only	EE + Spouse	EE + Child(ren)	EE + Family
HRA	\$185.95	\$489.51	\$410.81	\$714.36
HSA Plus	\$106.80	\$303.49	\$252.49	\$449.19
HSA Basic	\$40.34	\$147.33	\$119.59	\$226.57
Dental PPO	\$12.55	\$26.75	\$40.08	\$54.20
Dental DMO	\$9.37	\$19.93	\$22.56	\$33.11
Vision	\$6.82	\$12.93	\$13.61	\$20.41

Part-time Active Employee Contributions				
2025	EE Only	EE + Spouse	EE + Child(ren)	EE + Family
HRA	\$464.88	\$1,223.76	\$1,027.02	\$1,785.90
HSAPlus	\$267.00	\$758.71	\$631.22	\$1,122.97
HSABasic	\$100.85	\$368.31	\$298.97	\$566.42
Dental PPO	\$31.37	\$62.74	\$92.55	\$123.92
Dental DMO	\$23.43	\$46.89	\$52.73	\$76.17
Vision	\$6.82	\$12.93	\$13.61	\$20.41

Full-time Active Employer Subsidy				
2025	EE Only	EE + Spouse	EE + Child(ren)	EE + Family
HRA	\$592.09	\$1,338.89	\$1,145.28	\$1,892.08
HSAPlus	\$592.09	\$1,338.89	\$1,145.28	\$1,892.08
HSABasic	\$592.09	\$1,338.89	\$1,145.28	\$1,892.08
Dental PPO	\$18.82	\$35.99	\$52.47	\$69.72
Dental DMO	\$14.06	\$26.96	\$30.17	\$43.07

Confidential Exhibit ARC-10 is redacted in its entirety.

Confidential Exhibit ARC-11 is redacted in its entirety.

**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 Certain Regulatory And Accounting     )  
Treatments; and (4) All Other Required Approvals     )  
And Relief                                                         )

Case No. 2025-00257

**DIRECT TESTIMONY OF**  
**CLINTON M. STUTLER**  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
CLINTON M. STUTLER ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**DIRECT TESTIMONY OF  
CLINTON M. STUTLER ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is Clinton M. Stutler. My business address is 1 Riverside Plaza, Columbus, Ohio  
3       43215. I am employed by American Electric Power Service Corporation (“AEPSC”) as the  
4       Director of Natural Gas Procurement. AEPSC, is a wholly owned subsidiary of American  
5       Electric Power Company, Inc. (“AEP”). AEP is the parent company of Kentucky Power  
6       Company (“Kentucky Power” or the “Company”).

**II. BACKGROUND**

7   **Q.   PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
8       **BUSINESS EXPERIENCE.**

9   A.   I earned a Bachelor of Science in Business Administration degree, with a major in  
10       Transportation & Logistics and Marketing, from the Ohio State University in 2002, and a  
11       Master’s degree in Business Administration from Bowling Green State University in 2007.

12       I have 23 years of energy industry experience in fuel procurement, logistics,  
13       marketing, scheduling, and transportation. My professional background began in 2002 as  
14       a Scheduler with Marathon Petroleum Company. In 2008, I joined AEPSC in the Fuel,  
15       Emissions, and Logistics organization as a Coal Buyer, with responsibilities for the  
16       procurement of coal for Ohio Power Company. In 2014, I joined AEP Generation  
17       Resources, with responsibilities for purchasing natural gas, coal, urea, and fuel oil, in

1 addition to marketing fly ash and flue gas desulfurization gypsum. In 2016, I accepted a  
2 position in the regulated Commercial Operations organization as a Coal Buyer and became  
3 responsible for the procurement of coal for Appalachian Power Company (“APCo”),  
4 Kentucky Power, and Southwestern Electric Power Company (“SWEPCO”). On May 4,  
5 2018, I was promoted to Manager of Natural Gas and Fuel Oil Procurement, becoming  
6 responsible for the procurement and delivery of natural gas and fuel oil to AEP’s regulated  
7 generating fleet. On February 3, 2024, I was promoted to Director of Natural Gas  
8 Procurement.

9 **Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?**

10 A. I am responsible for the procurement and delivery of natural gas and fuel oil to AEP’s  
11 regulated generating fleet, which includes regulated power plants owned and/or operated  
12 by Kentucky Power and its affiliates.

13 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY**  
14 **PROCEEDINGS?**

15 A. Yes. I have submitted testimony and testified before the Public Service Commission of  
16 Kentucky on behalf of Kentucky Power in fuel adjustment clause review cases, including  
17 Case Nos. 2025-00073, 2024-00144, 2024-00136, and 2023-00008. I have also submitted  
18 testimony and testified before the Public Service Commission of West Virginia on behalf  
19 of APCo and Wheeling Power Company, and before the Oklahoma Corporation  
20 Commission on behalf of Public Service Company of Oklahoma (“PSO”). Furthermore, I  
21 have filed testimony before the Public Utility Commission of Texas and before the  
22 Arkansas Public Service Commission on behalf of SWEPCO, and before the State  
23 Corporation Commission of Virginia on behalf of APCo.

### **III. PURPOSE OF TESTIMONY**

1   **Q.   WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS**  
2   **PROCEEDING?**

3   A.   The purpose of my Direct Testimony in this proceeding is to discuss Kentucky Power's  
4       natural gas procurement strategy, which includes how Kentucky Power mitigates spot  
5       market price volatility, in connection with Kentucky Power's request to recover gains and  
6       losses on incidental gas sales (discussed further by Company Witness Wolfram). In  
7       addition, I support the total amount of gains and losses on incidental gas sales included  
8       within the test year.

### **IV. NATURAL GAS PROCUREMENT**

9   **Q.   PLEASE DESCRIBE HOW THE BIG SANDY PLANT IS SUPPLIED WITH**  
10   **NATURAL GAS.**

11   A.   Natural gas procurement for the Big Sandy Plant is based on two components: supply and  
12       transportation. Natural gas *supply* agreements provide the commodity used to fuel the  
13       power plant. Natural gas pipeline *transportation* agreements secure the necessary means  
14       to transfer the natural gas supply from the source to the plant.

15       The Big Sandy Plant utilizes a firm natural gas transportation agreement to move  
16       purchased natural gas supply from applicable receipt points. From a natural gas supply  
17       perspective, the Big Sandy Plant utilizes both baseload and spot market natural gas supply  
18       contracts. In order to mitigate spot market price volatility, forward-month, fixed-price  
19       natural gas supply is secured for the Big Sandy Plant. This practice is also called "hedging,"  
20       which I explain in more detail in the next section. Kentucky Power utilizes the spot natural



1 gas market to balance daily positions and makes additional purchases and sales as  
2 necessary.

## V. PHYSICAL NATURAL GAS HEDGING

### 3 Q. WHAT IS HEDGING?

4 A. Hedging is the practice of entering into transactions for the purpose of limiting exposure  
5 to one or more risks in a particular market. Kentucky Power's energy costs can be hedged  
6 by purchasing fixed-cost fuel for owned generation assets or by buying other energy  
7 products that fix the cost of the megawatt hours consumed. In this way, hedging brings  
8 greater energy cost certainty in advance of energy consumption.

### 9 Q. DOES KENTUCKY POWER CURRENTLY HEDGE ENERGY COSTS FOR ITS 10 CUSTOMERS?

11 A. Yes. Kentucky Power hedges energy costs using physical sources of energy, which  
12 includes natural gas. As described earlier, in order to mitigate spot market natural gas price  
13 volatility, Kentucky Power engages in physical natural gas hedging by securing  
14 forward-month, fixed-price natural gas supply for the Big Sandy Plant. These hedging  
15 purchases are made via a competitive request for proposal ("RFP") process. AEPSC, on  
16 behalf of Kentucky Power, issues RFPs to obtain specific quantities of baseload natural gas  
17 supply in specific forward months. Transactions are completed with the most reliable, least  
18 cost offers.

### 19 Q. HOW DOES HEDGING NATURAL GAS BENEFIT CUSTOMERS?

20 A. As explained below in my Direct Testimony, natural gas prices have been very volatile in  
21 the last several years. Kentucky Power's natural gas hedging strategy allows Kentucky  
22 Power to bring more fuel cost certainty and stability to customers, with the intent of helping

1 to levelize fuel costs. While I discuss some of the risks inherent in any hedging strategy  
2 later in my Direct Testimony, and as described in more detail by Company Witness  
3 Wolffram, Kentucky Power determined that providing more fuel cost certainty to  
4 customers through hedging outweighs those risks, to the benefit of customers.

5 **Q. PLEASE DESCRIBE KENTUCKY POWER'S COMPREHENSIVE ENERGY**  
6 **HEDGING PROGRAM.**

7 A. Kentucky Power forecasts weather-normalized customer load by month over a rolling  
8 36-month period and compares available fixed-cost resources in each month to that load.  
9 At predetermined milestones of 36 months, 18 months, and two to six months before flow,  
10 Kentucky Power increases the level of fixed-cost physical hedges to cover "target hedge  
11 percentages" of the weather-normalized customer load. These target hedge percentages  
12 increase over time to result in a larger portion of the cost of customer load becoming fixed.  
13 At each milestone, the lowest cost available alternative is chosen for procurement. Through  
14 this "layering" of resources beginning 36 months in advance of a flow month for energy,  
15 Kentucky Power also diversifies the market risk of procuring fixed-price fuel over time.

16 **Q. FOR THE BIG SANDY PLANT, WHAT IS THE MAXIMUM HEDGE QUANTITY**  
17 **THAT KENTUCKY POWER MAY PURCHASE FOR A SPECIFIC FORWARD**  
18 **MONTH AND HOW IS SUCH QUANTITY DETERMINED?**

19 A. The Big Sandy Plant is capable of consuming 72,000 million British thermal units  
20 ("MMBtu") per day of natural gas supply. However, such consumption is variable and is  
21 dependent on real-time market conditions. In general, when the Big Sandy Plant is online,  
22 consumption will range between 30,000 MMBtu and 60,000 MMBtu, which is dependent  
23 on real-time electricity demand. While it is impossible to accurately predict natural gas

1 consumption one day in advance, it is exponentially impossible to predict natural gas  
2 consumption months or years in advance. As a conservative, general rule, Kentucky Power  
3 limits forward natural gas physical hedge purchases to 32,000 MMBtu per day. However,  
4 in peak months where Kentucky Power has been projected to have an energy need,  
5 purchases of up to 43,000 MMBtu have been made.

6 There are some rare instances where Kentucky Power may purchase even greater  
7 quantities, but such events are the exception. For example, in advance of January 2024,  
8 when temperatures were expected to be significantly below normal, Kentucky Power  
9 purchased a total of 54,000 MMBtu per day. The weighted average of such supply equaled  
10 \$2.805 per MMBtu. As referenced in Section VI below, the Columbia Gas, App. market  
11 index, which is specific to the Big Sandy Plant, settled near \$14 per MMBtu for four  
12 consecutive days in January 2024. Because Kentucky Power pursued fixed-price, physical  
13 hedges (most of which were done months in advance) customers saved approximately \$2.4  
14 million in fuel costs during this four-day period.

15 **Q. WHAT ARE THE RISKS ASSOCIATED WITH PHYSICALLY HEDGING**  
16 **NATURAL GAS SUPPLY MONTHS IN ADVANCE OF FLOW?**

17 A. The primary risk is related to the uncertainty of demand. As illustrated in the previous  
18 section, Kentucky Power has been very thoughtful in its approach with regard to the timing  
19 and quantity related to forward month baseload purchases. However, forced and  
20 maintenance outages do occur, and planned outages change. In addition, changes in market  
21 conditions also impact the dispatch of the Big Sandy Plant, causing deviations in expected  
22 versus actual consumption. These risks are outweighed, however, by the impact of not

1 pursuing fixed-price, forward-month natural gas supply and, as a result, being fully  
2 exposed to spot market price volatility.

3 **Q. DOES PURCHASING FIXED-PRICE, FORWARD-MONTH BASELOAD**  
4 **NATURAL GAS SUPPLY ALWAYS RESULT IN LOWER FUEL COSTS?**

5 A. No, not always. But, the intent of Kentucky Power's hedging strategy is to limit exposure  
6 to spot market price volatility, and to spread market risk over time. At liquidation,  
7 sometimes the forward month purchases will be the least cost alternative, and sometimes  
8 the settled spot market price will be the least cost alternative. In the current market  
9 environment, physical natural gas hedging is essential in providing price stability and  
10 supply surety.

11 An example was provided above, where the purchase of fixed-priced,  
12 forward-month natural gas supply proved to be a substantial benefit to customers during a  
13 four-day period in January 2024. As calendar year 2024 progressed, the forward market  
14 was in continual decline (from one month to the next), and thus purchases made many  
15 months in advance were more expensive than spot market settlement pricing. Such  
16 purchases were either consumed at the Big Sandy Plant, or if the plant was not operating,  
17 the purchases were sold into the spot market at applicable pricing.

18 The market has become much stronger in January and February 2025. Kentucky  
19 Power had made prior baseload purchases equaling 32,000 MMBtu per day, priced at  
20 \$3.659 per MMBtu. Spot market pricing in January and February 2025 averaged \$4.192  
21 per MMBtu, and thus the baseload purchases were more favorable by \$1.01 million. As of  
22 the time of this filing, baseload purchases have been secured in eight forward months, as

1 far in the future as June 2027. These purchases are currently lower in cost than the projected  
2 forward month settlements.

3 **Q. HOW IS THE DEVIATION BETWEEN PHYSICAL NATURAL GAS**  
4 **PURCHASED AND ACTUAL NATURAL GAS CONSUMED MANAGED?**

5 A. There will always be a difference between natural gas purchased and natural gas consumed.  
6 The goal is to minimize the difference as much as possible, with such difference reverting  
7 to an Operational Balancing Account (“OBA”). An OBA is meant to account for small  
8 differences and is not to be used as storage or a more elaborate balancing tool. For example,  
9 assume that the OBA is flat, or zero. For a particular month, Kentucky Power has purchased  
10 32,000 MMBtu per day of forward baseload natural gas supply. On day one, the Big Sandy  
11 Plant consumed 34,000 MMBtu, creating an OBA deficit of 2,000 MMBtu. On day two,  
12 the Big Sandy Plant consumes 29,000 MMBtu, causing the OBA to now have a surplus of  
13 1,000 MMBtu. On day three through day five, the Big Sandy Plant is required to perform  
14 a maintenance outage. If the pipeline is unwilling to allow Kentucky Power to add 96,000  
15 MMBtu to its OBA, which would often be the case, the only other alternative is to sell the  
16 natural gas supply into the spot market.

17 **Q. DO MOST PIPELINES OPERATE IN THIS MANNER, AND ARE THERE**  
18 **DIFFERENT METHODS OF HANDLING LONG AND SHORT IMBALANCES?**

19 A. For Columbia Gas Transmission, which is the pipeline that serves the Big Sandy Plant, any  
20 balance on the OBA carries forward month-to-month. Other pipelines may have provisions  
21 in their tariffs that require daily or monthly cashouts. A cashout occurs when the excess  
22 quantity is sold to the pipeline, or the deficit is purchased from the pipeline (daily or

1 monthly basis). There also are provisions in the pipeline tariff or statement of operating  
2 conditions that specify how the sale and purchase price is derived.

3 **Q. WHAT IS KENTUCKY POWER PROPOSING WITH RESPECT TO GAINS OR**  
4 **LOSSES ON INCIDENTAL GAS SALES?**

5 A. As discussed in detail in the next section, energy market volatility has been elevated in  
6 recent years, and such volatility is expected to continue in the future. Mitigating spot  
7 market price risk, by competitively pursuing fixed-price, forward-month baseload natural  
8 gas supply is the appropriate path for customers.

9 However, securing this supply in advance can sometimes present some practical  
10 issues about how to handle any excess natural gas purchased and that is not ultimately used  
11 at the Big Sandy Plant. In these instances, Kentucky Power must sell that natural gas into  
12 the spot market. Once sold into the spot market, the price received for that gas may be  
13 higher or lower than the fixed-price Kentucky Power originally purchased it for, resulting  
14 in either a gain or loss on that sale.

15 Kentucky Power is proposing in this case that any gains or losses from such sales  
16 be included in and recovered from or credited to customers through the annual true-up  
17 mechanism in Tariff Purchase Power Adjustment (“P.P.A.”), which is explained in more  
18 detail by Company Witness Wolfram.

19 **Q. DID KENTUCKY POWER EXPERIENCE GAINS OR LOSSES ON INCIDENTAL**  
20 **SALES OF NATURAL GAS DURING THE TEST YEAR?**

21 A. For natural gas sales, which were made when the Big Sandy Plant did not ultimately require  
22 the prior purchased natural gas supply, Kentucky Power experienced net losses amounting  
23 to \$1.872 million during the test year (inclusive of offsetting gains). However, such losses

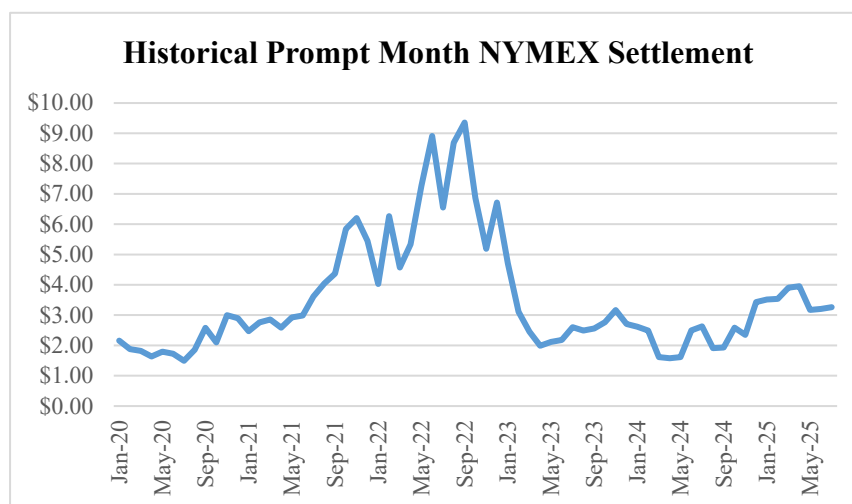
1 must be balanced with consumed fixed-price supply. In certain instances, the fixed-price  
2 natural gas supply under contract was lower than what could have been purchased in the  
3 spot market, an example of which is detailed in Section VI of my Direct Testimony.  
4 Because the Big Sandy Plant was operating, there was no need to sell these “in-the-money”  
5 fixed-price purchases, and thus customers enjoyed lower fuel costs during these periods of  
6 volatility.

7 As explained by Company Witness Wolfram, Kentucky Power proposes to set the  
8 test year amount of losses as the base amount for Tariff P.P.A., and to defer the \$1.872  
9 million of test year losses and amortize those costs through Tariff P.P.A., as well as  
10 proposing to recover gains and losses on incidental sales of gas going forward. As  
11 explained above, purchasing fixed-price natural gas supply is in the best interest of  
12 customers, thus it is reasonable to expect that any gains or losses resulting from this  
13 strategy, benefit, or be borne by customers.

## **VI. NATURAL GAS MARKET VOLATILITY**

14 **Q. HAS THE NATURAL GAS MARKET BEEN PARTICULARLY VOLATILE IN**  
15 **RECENT YEARS?**

16 A. Yes. As I discuss in detail below, the natural gas market has been quite volatile in recent  
17 years. Specifically, since about 2020, natural gas prices have fallen and risen inconsistently  
18 and unpredictably. Figure CMS-1 provides a visual representation of this volatility.

**Figure CMS-1**

**Q. IS SUCH PRICE VOLATILITY EXPECTED TO CONTINUE?**

A. Yes. Natural gas price volatility is expected to continue in the coming years due to factors such as, but not limited to, increasing demand for electricity, increasing global demand for liquefied natural gas (“LNG”), the increasing severity of winter storms, and potential imbalances between domestic natural gas supply and demand.

**Q. WHAT ACTION HAS KENTUCKY POWER TAKEN TO MITIGATE NATURAL GAS PRICE VOLATILITY?**

A. In early 2023, Kentucky Power began purchasing for the Big Sandy Plant specific quantities of fixed-price natural gas supply, for specific forward months to mitigate spot market natural gas price volatility. I explained this comprehensive hedging strategy in the previous section of my Direct Testimony. Such purchases provide price and supply surety and are immune to spontaneous movement that may occur in the spot market.



1 **Q. BEFORE DESCRIBING THE RECENT MARKET VOLATILITY, IT MAY BE**  
2 **HELPFUL TO UNDERSTAND SOME COMMON TERMS. CAN YOU EXPLAIN**  
3 **THE MEANING OF “INJECTION SEASON” AND “WITHDRAWAL SEASON”**  
4 **AND WHY THE ASSOCIATED STATISTICS ARE MEANINGFUL WITH**  
5 **REGARD TO NATURAL GAS PRICES AND SUPPLY?**

6 A. Injection season typically occurs between the months of April and October, when excess  
7 natural gas production is stored in preparation for the higher-demand winter months.  
8 Correspondingly, withdrawal season typically occurs between the months of November  
9 and March, when natural gas is withdrawn from storage to meet excess demand. Natural  
10 gas storage is closely monitored by the market, as storage is the best gauge of the balance  
11 between supply and demand. For example, if warmer than normal temperatures are  
12 experienced in the months of January and February, natural gas inventory will be elevated  
13 at the end of withdrawal season. Elevated inventory will limit injections during injection  
14 season, creating excess natural gas supply in the market, and causing overall prices to  
15 decrease.

16 **Q. CAN YOU PLEASE DESCRIBE THE MARKET VOLATILITY EXPERIENCED**  
17 **BEGINNING IN 2020?**

18 A. From calendar year 2015 through calendar year 2020, the prompt month New York  
19 Mercantile Exchange (“NYMEX”) contract averaged a settlement price below \$2.70 per  
20 MMBtu. Of particular interest during this time period is calendar year 2020, where prices  
21 were heavily influenced by the COVID-19 pandemic, which caused noticeable decreases  
22 in both domestic and global demand for natural gas. In fact, the prompt month NYMEX  
23 contract settled below \$2 per MMBtu from February 2020 through August 2020. To add

1 perspective, dating back to at least calendar year 2014, there were only a total of four  
2 months where the prompt month NYMEX price settled below \$2 per MMBtu. Due to very  
3 low demand and pricing, producers were forced to scale back on natural gas production.

4 **Q. PLEASE DESCRIBE THE MARKET SUBSEQUENT TO THE ONSET OF THE**  
5 **COVID-19 PANDEMIC.**

6 A. Following a colder than normal winter season in 2021, and correspondingly strong pulls  
7 from natural gas storage, the market began to recognize that the natural gas supply and  
8 demand balance would remain tight for the foreseeable future. Stronger demand for natural  
9 gas, from both a domestic and international perspective, coupled with a lack of natural gas  
10 production growth, caused natural gas prices to become much higher. By the final quarter  
11 of 2021, prompt month NYMEX contract prices were settling in the \$5 to \$6 per MMBtu  
12 range. Going from strong production and low demand to stagnant production and strong  
13 demand (in a very short period of time) put the wheels in motion for significant volatility  
14 into calendar year 2022.

15 “Unprecedented volatility” would best describe the natural gas market in calendar  
16 year 2022. There were 18 days in 2022 where the closing price of the NYMEX prompt  
17 month contract shifted by more than 10%. This was the largest number of days for such a  
18 shift since the NYMEX contract made its debut more than 30 years ago. In January 2022  
19 and February 2022, cold winter temperatures throughout the country resulted in natural gas  
20 storage withdrawals that surpassed the five-year average level by 28%. At the same time,  
21 demand for US LNG exports continued to increase. On February 24, 2022, Russia invaded  
22 Ukraine, which added further instability to an already volatile energy market and put more

1 pressure on US LNG exports, particularly to Europe. In early March 2022, global LNG  
2 prices spiked to nearly \$60 per MMBtu.

3 In April 2022, as the US natural gas market transitioned from withdrawal season to  
4 injection season, natural gas inventory was about 17% below the five-year average level.  
5 With storage much below average, weaker injections, and stagnant production, natural gas  
6 prices began a steep upward climb. The May 2022 NYMEX contract settled at \$7.27 per  
7 MMBtu, while the June 2022 NYMEX contract settled at \$8.91 per MMBtu. The last time  
8 prompt month NYMEX contracts settled in this range was during calendar year 2008.  
9 During the first week of June 2022, the July 2022 NYMEX was trading above \$9.50 per  
10 MMBtu. Then, on June 8, 2022, there was an explosion and fire at the Freeport LNG  
11 terminal. This facility exports the equivalent of 2 billion of cubic feet (“Bcf”) per day of  
12 natural gas, which equates to approximately 2% of total domestic dry gas production. After  
13 about a week, it was determined that due to the damage, the facility would be in an outage  
14 until late 2022, which meant that 2 Bcf per day of natural gas would be backed into the  
15 domestic market providing additional supply. This caused the July 2022 NYMEX contract  
16 to retreat into the \$6 per MMBtu range, ultimately settling at \$6.55 per MMBtu.

17 As the market entered the peak summer months of July 2022 and August 2022,  
18 natural gas production began to trend higher. In addition, despite the elevated prices,  
19 natural gas demand from domestic power generators remained at record levels throughout  
20 the summer. The August 2022 NYMEX contract settled at \$8.69 per MMBtu, while the  
21 September 2022 NYMEX contract settled at \$9.35 per MMBtu. Injections to storage were  
22 about 6% lower than the five-year average, which was not helpful considering total

1 domestic inventory was low at the outset. In the international market, global demand for  
2 LNG was still very high, with record prices assessed above \$70 per MMBtu.

3 During the month of September 2022, storage injections started to become stronger.  
4 The market began seeing weekly injections outpacing the five-year average, making the  
5 total storage deficit smaller. This, in turn, caused natural gas forward market and spot  
6 market prices to decrease. The October 2022 NYMEX contract settled at \$6.87 per  
7 MMBtu, which was a decrease of about 27% from the prior month.

8 Strong storage injections, as well as record natural gas production, continued into  
9 October 2022. By mid-October, there was a run of four consecutive triple-digit storage  
10 injections, which is a streak that had only been observed twice in the last decade. By the  
11 end of the month, the storage deficit to the five-year average had shrunk to under 4%. This  
12 is quite an accomplishment considering that injection season began at a 17% deficit to the  
13 five-year average.

14 In early November 2022, with unseasonably warm weather and low demand, spot  
15 market prices started to collapse. In fact, during the first two weeks of the month, the  
16 Columbia Gas, App. market index, which is the applicable index for the Big Sandy Plant,  
17 averaged a daily settlement price of \$2.73 per MMBtu. In the international market, demand  
18 for LNG started to wane and prices retreated below \$14 per MMBtu. In the second half of  
19 the month, cold weather returned which caused spot prices to rebound to over \$5 per  
20 MMBtu. However, the important news was that domestic storage levels had increased at  
21 such a pace that total inventory was now consistent with the five-year average. The  
22 December 2022 NYMEX contract settled at \$6.71 per MMBtu.

**Q. WHAT DEVELOPMENTS PRIMED THE TRAJECTORY OF THE NATURAL GAS MARKET FOR CALENDAR YEAR 2023?**

A. There were two significant developments during the month of December 2022. The first was Winter Storm Elliott, which wreaked havoc in the PJM service territory. While demand was very high, spot market natural gas prices in the supply-rich Appalachian Basin were much lower than expected. During the storm, the Columbia Gas, App. market index settled between \$6.20 and \$7.43 per MMBtu.

The second significant development was the situation regarding the forward natural gas market. Despite the problems that the cold weather associated with Winter Storm Elliott was causing, the forward market was simultaneously collapsing. The 11- to 15-day weather forecast predicted above normal temperatures and the market was reacting. In the final days of calendar year 2022, the Columbia Gas, App. spot price settled just above the \$3 per MMBtu mark. The January 2023 NYMEX contract settled at \$4.71 per MMBtu, which was the lowest monthly settlement in almost a year.

As the market moved into January 2023, the mild winter weather continued to put downward pressure on natural gas prices. In fact, in the middle of the month, rather than a small storage withdrawal, there was a small storage injection reported. This was the first January storage injection on record, according to EIA data going back to 1994. Over the last 30 years, the US has only had a weekly injection five times during the months of December, January, and February, with the last injection occurring in December 2017. From an international perspective, Europe was experiencing the same type of weather conditions. According to data from Gas Infrastructure Europe, natural gas storage levels in Europe were 80% full in mid-January. This compares to levels closer to 45%, experienced

1 the year prior. The February 2023 NYMEX contract settled at \$3.11 per MMBtu, which  
2 was a 19-month low.

3 Above-normal temperatures continued to put downward pressure on natural gas  
4 prices into February 2023. As the most typically severe winter months (December through  
5 February) were coming to an end, it became apparent that storage would end withdrawal  
6 season at a significant surplus to the five-year average. In fact, if production were to remain  
7 strong, by the next withdrawal season, total storage would be expected to match or surpass  
8 historical records. The March 2023 NYMEX contract settled at \$2.45 per MMBtu, with  
9 the April 2023 NYMEX contract settling at \$1.99 per MMBtu. This was the first time that  
10 the prompt month contract settled below \$2.00 per MMBtu since August 2020.

11 At the start of the 2023 injection season, natural gas injections into storage were  
12 very strong. During the first two weeks of April 2023, total inventory increased by 100  
13 Bcf, exceeding the five-year average injection for the corresponding time period of 69 Bcf.  
14 Strong injections continued into May 2023, and by early June 2023, total storage injections  
15 were about 9% higher than the five-year average. Strong production and healthy storage  
16 continued to weigh heavily on market prices as the May 2023 and June 2023 prompt month  
17 NYMEX contracts settled at \$2.12 per MMBtu and \$2.18 per MMBtu, respectively.

18 During the summer months, excessive heat was experienced across Texas and the  
19 Midcontinent Region. The associated cooling demand caused natural gas-fired power  
20 burns to set daily records, at more than 50 Bcf. The hot weather caused a slowdown in  
21 storage injections and moderate increases in natural gas pricing. By the end of August  
22 2023, total storage injections were now just slightly below the five-year average. The

1 prompt month NYMEX contracts for the months of July 2023, August 2023, and  
2 September 2023 settled in the \$2.50 to \$2.60 per MMBtu range.

3 The stretch of below-average storage injections continued into the fall shoulder  
4 season. By mid-September 2023 the market realized the eleventh consecutive  
5 below-average injection, which caused the total inventory surplus to retreat to 7% above  
6 average. From a natural gas production standpoint, production was robust throughout the  
7 year, which helped to offset the higher consumption, and to keep total storage at a surplus  
8 to the average.

9 While prompt prices remained relatively low, the forward market was stronger. Due  
10 to the winter risk associated with the months of January and February, in early October  
11 2023 the forward NYMEX contract for the months of January 2024 and February 2024  
12 was trading just below \$4.00 per MMBtu. As injection season was coming to an end, total  
13 storage was near 3.8 trillion cubic feet (“Tcf”), which was about 5% higher than average.  
14 Even with the bearish sentiment in the market, due to high storage and strong production,  
15 the November 2023 NYMEX contract settled at \$3.16 per MMBtu, which was the first  
16 prompt month settlement above \$3.00 per MMBtu since the very beginning of the year.

17 However, any potential bull run regarding natural gas prices was quickly dismissed  
18 as the market entered November 2023. Typically, in the month of November, the market  
19 will see a net storage withdrawal of 41 Bcf. In November 2023, the market saw a net  
20 storage *injection* of 57 Bcf. The December 2023 NYMEX contract ultimately settled at  
21 \$2.71 per MMBtu. Weather forecasts continued to warm up, causing lower natural gas  
22 demand, and corresponding lower natural gas prices. As the days rolled forward, the market  
23 continued losing heating degree days in the month of December 2023. In fact, by the time

December 2023 came to a close, it was recorded as the third warmest December since 1950. At the same time, the market was witnessing record high natural gas production. These events, coupled with above average natural gas storage, removed much of the winter premium from the forward market. The January 2024 NYMEX contract settled at \$2.62 per MMBtu.

**Q. DID THE MARKET WEAKNESS CONTINUE INTO 2024?**

A. Yes, with one exception. By early January 2024, withdrawals from natural gas storage totaled 289 Bcf, which was 28% below the five-year average. However, the weather forecast was shifting much cooler, with the storage surplus expected to soon narrow by triple digits due to excessive demand. Between January 13, 2024, and January 16, 2024, spot market pricing applicable for the Big Sandy Plant increased to nearly \$14 per MMBtu. Total natural gas demand during this period reached an all-time high (greater than both Winter Storm Uri and Winter Storm Elliott). At the same time, due to well freeze-offs and other weather-related problems, natural gas production decreased by more than 10%. The storage withdrawal during the winter storm exceeded 300 Bcf, which was only the third time in history the withdrawal has met that benchmark. Throughout calendar year 2023, Kentucky Power had made multiple fixed-price, physical natural gas purchases for January 2024 delivery, thus the Company's customers were somewhat protected from the volatile spot market prices.

Subsequent to the winter storm, the natural gas storage surplus began to erode, as total inventory was moving toward average levels. However, the weather forecast was projecting plenty of warmth, putting a lid on any potential bull market run. The February 2024 NYMEX contract settled at \$2.49 per MMBtu. By the time that February 2024 was



1 over, it was recorded as the second warmest February since 1950. With winter over, and  
2 natural gas storage and production as strong as ever, the March 2024 NYMEX contract  
3 settled at \$1.62 per MMBtu, while the April 2024 NYMEX contract settled at \$1.58 per  
4 MMBtu. Because of the steep decline in pricing, the market clearly oversupplied, and the  
5 lack of opportunity to reverse course, producers began to announce production cuts.

6 During the month of April 2024, the production cuts started to become realized, as  
7 production decreased by approximately 5% from the 2023 peak. Nevertheless, injections  
8 into storage continued to outpace the five-year average. Forward pricing remained  
9 extremely depressed with the May 2024 NYMEX contract settling at \$1.61 per MMBtu.

10 In May 2024, the market started to see consecutive below-average storage  
11 injections. The lower storage injections began to close the gap between actual and average  
12 storage levels. The June 2024 NYMEX contract settled at \$2.49 per MMBtu, sharply  
13 higher than the previous three months. By the beginning of June 2024, storage injections  
14 totaled 536 Bcf, or about 8% lower than the five-year average. Weak storage injections  
15 were expected to continue through the summer, supported by warming temperatures, rising  
16 gas-fired power demand and the eventual end to LNG terminal maintenance, which limited  
17 feedgas demand for much of the spring.

18 With the continued warm weather, the July 2024 NYMEX contract settled at \$2.63  
19 per MMBtu. Into July 2024, the market continued seeing below-average inventory  
20 injections, which limited inventory growth. Storage injections lagged the five-year average  
21 by 14% by the middle of the month. It was reported that June 2024 and July 2024 were the  
22 warmest in the last 130 years.

1 With stronger pricing, the market began seeing additional natural gas production  
2 return. With production returning, and LNG feedgas demand waning, natural gas forward  
3 pricing returned to the bearish side. The August 2024 NYMEX contract settled at \$1.91  
4 per MMBtu, with the September 2024 NYMEX contract settling at \$1.93 per MMBtu.

5 By mid-September 2024, natural gas injections totaled 1.09 Tcf, which was 22%  
6 below average. For the balance of the month, storage injections continued to be on the low  
7 side, further dwindling the storage surplus. By the end of September 2024, weather  
8 forecasts were predicting lingering hot weather into October 2024, which would continue  
9 to support strong natural gas-fired power demand. The October 2024 NYMEX contract  
10 settled at \$2.59 per MMBtu.

11 By mid-October 2024, it was recognized that if storage injections continued to lag  
12 average levels by the same margin for the balance of the month, total inventory would  
13 decrease to less than 3% above average. By the end of the month, October 2024 was  
14 recognized as the third warmest October in the US in the last 60 years. However, warm  
15 October weather is received differently than warm July or August weather. Storage  
16 injections were stronger during the second half of the month, exceeding average injections  
17 for the corresponding period.

18 **Q. PLEASE EXPLAIN THE APPLICABLE MARKET SHIFT AT THE END OF**  
19 **CALENDAR YEAR 2024, LEADING INTO CALENDAR YEAR 2025.**

20 A. Exceptionally mild weather during November 2024 kept heating demand much below  
21 average. Instead of the expected storage withdrawals, the market saw continued injections,  
22 which strengthened the overall inventory position. Furthermore, the United States was  
23 beginning winter heating season with its highest level of natural gas storage since 2016.

1        However, toward the end of November 2024 it became clear that a shot of cold weather  
2        would hit the United States in the beginning of December 2024. The expected cold weather  
3        caused spot market pricing to jump above the \$3.00 per MMBtu threshold. The December  
4        2024 NYMEX contract settled at \$3.43 per MMBtu, which was the highest prompt month  
5        settlement since January 2023.

6                By mid-December 2024, the market realized the first triple digit withdrawal of the  
7        season, substantially above the average withdrawal for the corresponding week. With cold  
8        weather in December 2024, more cold weather expected in January 2025, as well as large  
9        withdrawals from storage, the market was setting itself up to become more bullish, from a  
10       natural gas pricing perspective. The January 2025 NYMEX contract settled at \$3.51 per  
11       MMBtu.

12               After the first week of January 2025, it was reported that withdrawals from storage  
13       totaled 559 Bcf, approximately 15% higher than average. With additional cold weather  
14       expected, which would most likely impact natural gas production, spot market pricing  
15       started to become volatile. Similar to January 2024, Kentucky Power was insulated from  
16       this spot market volatility as a significant quantity of purchases for the Big Sandy Plant  
17       were made many months prior, at fixed prices.

18               In addition to the expected cold weather, LNG feedgas demand was hitting record  
19       highs, creating additional momentum for rising prices. Cold weather continued to persist  
20       throughout the month, and by the time January 2025 was over, it was considered the third  
21       coldest January this century, and the coldest January in the last decade. Continued strong  
22       storage withdrawals caused inventory to dip below the five-year average for the first time  
23       in two years.

1 Additional cold weather was in store for February 2025. By mid-month, it was  
2 reported that from the first withdrawal of the season, US natural gas storage had dropped  
3 by 1.575 Tcf, or 27% larger than the five-year average. By the end of February 2025, the  
4 March 2025 NYMEX contract was trading above \$4.25 per MMBtu, which was the highest  
5 prompt month value seen since December 2022. Ultimately, the contract retreated and  
6 settled at \$3.91 per MMBtu. In March 2025, the natural gas market quickly transitioned  
7 from below average storage withdrawals to above average storage injections. For the week  
8 ending March 14, 2025, the EIA reported a surprise storage injection of 9 Bcf. Typically,  
9 during this time period, the market is still withdrawing natural gas from storage. Natural  
10 gas storage injections have continued to be strong, causing forward prices to retreat. In fact,  
11 between April 2025 and June 2025, the EIA reported seven consecutive triple digit storage  
12 injections, which was the longest streak since June 2014. Correspondingly, the May 2025  
13 and June 2025 NYMEX contracts became much weaker than prior months, settling at \$3.17  
14 and \$3.20 per MMBtu, respectively. However, many analysts are seeing natural gas market  
15 strength heading into the second half of 2025 as demand for natural gas is expected to  
16 outstrip supply. This strength is expected to become even more prevalent in 2026.

17 As presented in the foregoing, the natural gas market has been impacted by events  
18 that have caused natural gas prices to fluctuate from one extreme to the other. Kentucky  
19 Power's comprehensive natural gas hedging strategy helps mitigate against this kind of  
20 volatility by limiting exposure to spot market price volatility and spreading market risk  
21 over time.

**VII. CONCLUSION**

1    **Q.     DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

2    **A.     Yes.**

## VERIFICATION

The undersigned, Clinton M. Stutler, being duly sworn, deposes and says he is the Director of Natural Gas Procurement 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.

Signed by:

*Clinton M. Stutler*

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Clinton M. Stutler

Commonwealth of KY

County of Boyd

Case No. 2025-00257

Subscribed and sworn to before me, a Notary Public in and before said County  
and State, by Clinton M. Stutler, on 8/22/2025 | 9:07 AM EDT.

Signed by:

*Michelle Caldwell*

E9B1BC7AC31F421...

Notary Public

MARILYN MICHELLE CALDWELL  
ONLINE NOTARY PUBLIC  
COMMONWEALTH OF KENTUCKY  
Commission #KYNP71841  
My Commission Expires 5/5/2027

My Commission Expires 05/05/2027

Notary ID Number KYNP71841

**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;	)	Case No. 2025-00257
(3) Approval Of Certain Regulatory And Accounting	)	
Treatments; and (4) All Other Required Approvals	)	
And Relief	)	

**DIRECT TESTIMONY OF**  
**TIMOTHY S. LYONS**  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
TIMOTHY S. LYONS  
ON BEHALF OF KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**LIST OF EXHIBITS**

Exhibit TSL-1 – Summary of Qualifications

Exhibit TSL-2 – Summary of Lead-Lag Study

Exhibit TSL-3 – Lead-Lag Schedules



1    **I.    INTRODUCTION**

2    **Q.    PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3    A.    My name is Timothy S. Lyons. My business address is 1 Speen Street, Suite 150,  
4        Framingham, Massachusetts 01701.

5    **Q.    BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

6    A.    I am a Partner at ScottMadden, Inc. (“ScottMadden”).

7    **Q.    ON WHOSE BEHALF ARE YOU SPONSORING THIS TESTIMONY?**

8    A.    I am sponsoring this testimony on behalf of the Kentucky Power Company (the  
9        “Company”).

10   **Q.    WOULD YOU PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE?**

11   A.    I have more than 30 years of experience in the energy industry. I started my career in 1985  
12        at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis.  
13        In 1993, I moved to Providence Gas Company, eventually becoming Vice President of  
14        Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting  
15        positions in the energy industry, first at KEMA and then at Quantec, LLC. In 2005, I  
16        became Vice President of Sales and Marketing at Vermont Gas Systems, Inc., before  
17        joining Sussex Economic Advisors, LLC (“Sussex”) in 2013. Sussex was acquired by  
18        ScottMadden in 2016.

1   **Q.    WHAT IS YOUR EDUCATIONAL BACKGROUND?**

2    A.    I hold a bachelor's degree from St. Anselm College, a master's degree in economics from  
3           The Pennsylvania State University, and a master's degree in business administration from  
4           Babson College.

5   **Q.    HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THE PUBLIC**  
6       **SERVICE COMMISSION OF KENTUCKY?**

7    A.    Yes. I have sponsored testimony before more than 30 U.S. and Canadian regulatory  
8           authorities. A summary of my qualifications is included in Exhibit TSL-1.

9   **II.   PURPOSE AND OVERVIEW OF TESTIMONY**

10   **Q.    WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

11   A.    The purpose of my testimony is to sponsor the results of the lead-lag study. The lead-lag  
12       study was used to determine the Company's cash working capital ("CWC") requirement.<sup>1</sup>

13   **Q.    HAVE YOU PREPARED EXHIBITS SUPPORTING YOUR TESTIMONY?**

14   A.    Yes. I am sponsoring the exhibits in the list of exhibits (above). The exhibits were  
15       prepared by me or under my direction.

16   **Q.    PLEASE DEFINE THE TERM "CASH WORKING CAPITAL."**

17   A.    The term "working capital" refers to the net funds required by the Company to finance  
18       goods and services used to provide service to customers from the time those goods and

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<sup>1</sup> The Commission directed the Company in Case No. 2020-00174 to submit a lead-lag study in all general rate case filings until further notice. *See* Order at 9, *In The Matter Of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) For 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. Jan. 13, 2021).

1 services are paid for by the Company to the time that payment is received from customers.  
2 Goods and services considered in this lead-lag study included: operations and maintenance  
3 (“O&M”) expenses, including labor and non-labor expenses; income taxes; and taxes other  
4 than income taxes.

5 **Q. HOW WAS THE COMPANY’S CWC REQUIREMENT DETERMINED?**

6 A. The Company’s CWC requirement was determined by applying the results of the lead-lag  
7 study to the Company’s adjusted test year expenses. The lead-lag study compares  
8 differences between the Company’s revenue lags and expense leads.

9 The revenue lag represents the number of days from the time customers receive  
10 service to the time customers pay for their service, *i.e.*, when funds are available to the  
11 Company. The longer the revenue lag, the more cash the Company needs to finance its  
12 day-to-day operations.

13 The expense leads represent the number of days from the time the Company  
14 receives goods and services used to provide electric service to the time payments are made  
15 for those goods and services, *i.e.*, when the funds are no longer available to the Company.  
16 The longer the expense leads, the less cash the Company needs to fund its day-to-day  
17 operations.

18 Together, the revenue lag and expense leads are used to develop lead-lag days. The  
19 Company’s CWC requirement was determined by applying the results of the lead-lag study  
20 to the Company’s adjusted test year expenses. The Company’s CWC requirement is  
21 included in the Company’s proposed rate base, which is sponsored by Company Witness  
22 Ciborek.

1    **III.    LEAD-LAG STUDY APPROACH**

2    **Q.    PLEASE SUMMARIZE THE APPROACH USED TO DEVELOP THE LEAD-LAG**  
3    **STUDY.**

4    A.    The lead-lag study compares differences between the Company's revenue lag and expense  
5    leads. The revenue lag measures the number of days from the time service is provided to  
6    customers to the time payment is received from customers. Expense leads measure the  
7    number of days from the time goods and services used to provide utility service are  
8    provided to the Company to the time payments are made by the Company for those goods  
9    and services. The revenue lag and expense leads are measured in days for individual  
10   expenses and then converted to "dollar-days" that reflect a weighting by expense amounts.

11   **Q.    DO THE METHODOLOGIES USED IN THIS LEAD-LAG STUDY GENERALLY**  
12   **FOLLOW INDUSTRY PRACTICE AND ARE THEY GENERALLY CONSISTENT**  
13   **WITH THE METHODOLOGIES USED IN THE COMPANY'S MOST RECENT**  
14   **RATE CASE FILING?**

15   A.    Yes. The methodologies used in this lead-lag study generally follow industry practice and  
16   are generally consistent with the methodologies used in the Company's most recent base  
17   rate case filing.

18   **Q.    PLEASE DESCRIBE THE FINANCIAL DATA USED TO DEVELOP THE LEAD-**  
19   **LAG STUDY.**

20   A.    The lead-lag study was based on the Company's test year financial data from April 1, 2024,  
21   through March 31, 2025. The data included customer revenues, O&M expenses, and  
22   federal, state, local, and employment taxes.

1   **Q.     PLEASE SUMMARIZE THE RESULTS OF THE LEAD-LAG STUDY.**

2   A.     The results of the lead-lag study are summarized in Exhibit TSL-2.

3       **A.     Revenue Lag**

4   **Q.     HOW WAS THE REVENUE LAG DETERMINED?**

5   A.     The revenue lag measures the number of days from the time electric service is provided to  
6           customers to the time payment is received from customers. The revenue lag consists of  
7           three components:

8               **Service lag** – measures the average number of days in the service period (*i.e.*, the  
9               time between the start and end of the billing month);

10              **Billing lag** – measures the number of days from the time meters are read to the time  
11              bills are recorded and sent to customers;

12              **Collection lag** – measures the number of days from the time bills are recorded and  
13              sent to customers to the time customer payments are received (*i.e.*, funds are  
14              available to the Company).

15           The revenue lag of 1.44 days in this study was based on the Company's accounts  
16           receivables factoring process, which reflects payments to the Company (*i.e.*, funds are  
17           available to the Company) on the business day after the electricity is used. The revenue  
18           lag is shown in Exhibit TSL-3.

1        **B.     Expense Lead Days**

2        **Q.     HOW WERE LEAD DAYS FOR EXPENSES DETERMINED?**

3        A.     Lead days for expenses were measured separately for the following expense categories: (1)  
4               Operations and Maintenance (“O&M”) expenses; (2) Income Taxes; (3) Taxes Other than  
5               Income Taxes; and (4) Interest Payments on Long-Term Debt.

6               **1.     O&M Expenses**

7        **Q.     HOW WERE LEAD DAYS FOR O&M EXPENSES DETERMINED?**

8        A.     Lead days for O&M expenses were measured separately for the following expense  
9               categories: (1) fuel expenses; (2) purchased power expenses; (3) payroll expenses,  
10              including vacation pay and incentive compensation expenses; (4) savings plan and benefits;  
11              and (5) other O&M expenses.

12       **Q.     HOW WERE LEAD DAYS FOR FUEL EXPENSES DETERMINED?**

13       A.     Lead days for fuel expenses were measured separately for coal, oil and natural gas and then  
14               dollar-weighted by payment amounts. Lead days for natural gas expenses of 40.80 days as  
15               shown in Exhibit TSL-2 were based on the number of days from the midpoint of the service  
16               period to the payment date. The midpoint reflects the average number of days in the service  
17               period (*i.e.*, the time between the start and end of the service period). Lead days for coal  
18               and oil of 12.82 days as shown in Exhibit TSL-2 were based on the number of days from  
19               the shipment date to the payment date.

1 **Q. HOW WERE LEAD DAYS FOR PURCHASED POWER EXPENSES**  
2 **DETERMINED?**

3 A. Lead days for purchased power expenses of 29.66 days as shown in Exhibit TSL-2 were  
4 based on the number of days from the midpoint of the service period to the payment date  
5 for each payment and then dollar-weighted by payment amounts.

6 **Q. HOW WERE LEAD DAYS FOR REGULAR PAYROLL EXPENSES**  
7 **DETERMINED?**

8 A. Lead days for regular payroll expenses of 24.46 days as shown in Exhibit TSL-2 were  
9 based on the Company's payroll process, which pays employees on a bi-weekly basis.  
10 Lead days were based on the number of days from the midpoint of the payroll period to the  
11 payroll payment date.

12 **Q. DOES THE LEAD-LAG STUDY ADJUST FOR VACATION PAY?**

13 A. Yes, the lead-lag study adjusts for vacation pay. The adjustment reflects that vacation pay  
14 is earned before it is taken. The adjustment is based on the midpoint of the calendar year.

15 **Q. HOW WERE LEAD DAYS FOR THE ANNUAL INCENTIVE PAYMENTS**  
16 **DETERMINED?**

17 A. Lead days for the annual incentive payments of 256.00 days as shown in Exhibit TSL-2  
18 were based on the number of days from the midpoint of the performance period to the  
19 payment date.

1 **Q. DOES THE LEAD-LAG STUDY ADJUST FOR CASH RECEIPTS OF PAPER**  
2 **CHECKS?**

3 A. Yes, the lead-lag study adjusts for cash receipts of paper checks. The adjustment reflects  
4 that wages paid by paper checks clear a few days after payroll is disbursed (i.e., when funds  
5 are no longer available to the Company). The adjustment in this study was based on  
6 analysis of clearing dates for paper checks issued by the Company. Wages paid by direct  
7 deposit clear on the day payroll is disbursed.

8 **Q. HOW WERE LEAD DAYS FOR SAVINGS PLAN AND BENEFITS**  
9 **DETERMINED?**

10 A. Lead days for the savings plan and benefits of 28.75 days as shown in Exhibit TSL-2 were  
11 based on the number of days from the midpoint of the service period to the payment date.

12 **Q. HOW WERE LEAD DAYS FOR OTHER O&M EXPENSES DETERMINED?**

13 A. Lead days for other O&M expenses of 19.82 days as shown in Exhibit TSL-2 were  
14 measured separately for the following categories: (1) AEP Service Corporation expenses;  
15 (2) AEP Inter-Company expenses; and (3) Other O&M expenses.<sup>2</sup>

16 **Q. HOW WERE LEAD DAYS FOR AEP SERVICE CORPORATION EXPENSES**  
17 **DETERMINED?**

18 A. Lead days for AEP Service Corporation expenses were based on the number of days from  
19 the midpoint of the service period to the payment date. The payments are made  
20 electronically; thus, there are no adjustments to the study for cash receipts of paper checks.

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<sup>2</sup> Please note during preparation of this testimony, and after the Company's revenue requirement had been finalized for customer notification, an inadvertent calculation error was discovered that increased the calculation of lead days for other O&M expenses. The correct lead days should be 37.38 days instead of 19.82.



1 **Q. HOW WERE LEAD DAYS FOR AEP INTER-COMPANY EXPENSES**  
2 **DETERMINED?**

3 A. Lead days for AEP Inter-Company expenses were based on the number of days from the  
4 midpoint of the service period to the payment date.

5 **Q. HOW WERE LEAD DAYS FOR OTHER O&M EXPENSES DETERMINED?**

6 A. Lead days for Other O&M expenses were based on the sum of three components: (1) lead  
7 days from the service period to the invoice date; (2) lead days from the invoice date to the  
8 payment date; and (3) lead days from the payment date to the check clear date.

9       Lead days from the service period to the invoice date were based on a stratified  
10 sample of invoices paid by the Company from April 1, 2024, through March 31, 2025.

11       Lead days were measured for each invoice in the sample as the number of days from the  
12 midpoint of the service period to the invoice date. Invoices were then dollar-weighted by  
13 invoice amounts to determine the lead days.

14       Lead days from the invoice date to the payment date were based on invoices paid  
15 by the Company from April 1, 2024, through March 31, 2025. Lead days were measured  
16 for each invoice as the number of days from the invoice date to the payment date. Invoices  
17 were then dollar-weighted by invoice amounts to determine the lead days.

18       Lead days from the payment date to the check clear date were based on invoices  
19 paid by the Company from April 1, 2024, through March 31, 2025. Lead days were  
20 measured for each invoice as the number of days from the payment date to the check clear  
21 date. Invoices were then dollar-weighted by invoice amounts to determine the lead days.

1                   **2.       Federal and State Income Taxes**

2   **Q.       HOW WERE LEAD DAYS FOR FEDERAL INCOME TAXES DETERMINED?**

3   A.       Lead days for federal income taxes of 37.50 days as shown in Exhibit TSL-2 were based  
4           on due dates for tax payments: April 15, June 15, September 15, and December 15. Lead  
5           days for federal income taxes were measured as the number of days from the midpoint of  
6           the taxing period (*i.e.*, the calendar year) to the due dates. The study assumes the tax  
7           payments reflect equal installments.

8   **Q.       HOW WERE LEAD DAYS FOR STATE INCOME TAXES DETERMINED?**

9   A.       Lead days for state income taxes of 37.50 days as shown in Exhibit TSL-2 were based on  
10          due dates for tax payments: April 15, June 15, September 15, and December 15. Lead days  
11          for state income taxes were measured as the number of days from the midpoint of the taxing  
12          period (*i.e.*, the calendar year) to the due dates. The study assumes the tax payments reflect  
13          equal installments.

14                   **3.       Taxes Other than Income Taxes**

15   **Q.       HOW WERE LEAD DAYS FOR TAXES OTHER THAN INCOME TAXES**  
16   **DETERMINED?**

17   A.       Lead days for taxes other than income taxes were measured separately for the following  
18          categories: (1) Payroll-related taxes (FICA, Federal Unemployment, and State  
19          Unemployment); (2) Utility Gross Receipts License Tax (UGRLT); (3) Property taxes; (4)  
20          Sales & Use Tax; (5) Kentucky Sales and Use Tax - Energy Exemption Annual Return;  
21          and (6) Other taxes (Federal Excise Tax, Local Franchise Fee, Local Street Lighting Fee).

1   **Q.   HOW WERE LEAD DAYS FOR PAYROLL TAXES DETERMINED?**

2   A.   Lead days for FICA taxes of 27.31 days, Federal Unemployment taxes of 30.09 days, State  
3       Unemployment – Kentucky taxes of 30.07 days, and State Unemployment – West Virginia  
4       tax of 30.45 days, as shown in Exhibit TSL-2, were based on the number of days from the  
5       midpoint of the taxing period to the payment date.

6   **Q.   HOW WERE LEAD DAYS FOR UGRLT AND SALES AND USE TAXES**  
7       **DETERMINED?**

8   A.   Lead days for UGRLT taxes of 34.87 days, Sales and Use taxes of 40.13 days, and Sales  
9       and Use – Energy Exemption taxes of 34.88 days, as shown in Exhibit TSL-2, were based  
10      on the number of days from the midpoint of the taxing period to the payment date.

11   **Q.   HOW WERE LEAD DAYS FOR PROPERTY TAXES DETERMINED?**

12   A.   Lead days for property taxes of 365.90 days, as shown in Exhibit TSL-2, were measured  
13      separately for each property tax payment. Lead days were based on the number of days  
14      from the midpoint of the taxing period to the payment date.

15   **Q.   HOW WERE LEAD DAYS FOR FEDERAL EXCISE TAXES, AND LOCAL**  
16       **FRANCHISE AND STREETLIGHTING FEES DETERMINED?**

17   A.   Lead days for Federal Excise taxes of 76.24 days, and Local Franchise fees of 47.96 days,  
18      and streetlighting fees of 207.72 days, as shown in Exhibit TSL-2, were based on the  
19      number of days from the midpoint of the taxing period to the payment date.

1                   **4.     Interest Expense**

2   **Q.     HOW WERE LEAD DAYS FOR INTEREST PAYMENTS ON LONG-TERM**  
3   **DEBT DETERMINED?**

4   A.     Interest payments on the Company's long-term debt of 82.99 days, as shown in Exhibit  
5           TSL-2, are generally made at the end of the borrowing period. Lead days for interest  
6           payments on long-term debt were based on the number of days from the midpoint of the  
7           borrowing period to the payment date.

8   **IV.    CONCLUSION**

9   **Q.     WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?**

10  A.     The results of the lead-lag study are shown in Exhibit TSL-2. The methodologies used in  
11           the lead-lag study generally follow industry practice and are generally consistent with the  
12           methodology used in the Company's most recent rate case filing.<sup>3</sup>

13           The results of the lead-lag study when applied to the Company's adjusted test year  
14           expenses are used to determine the Company's CWC requirement.

15  **Q.     DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

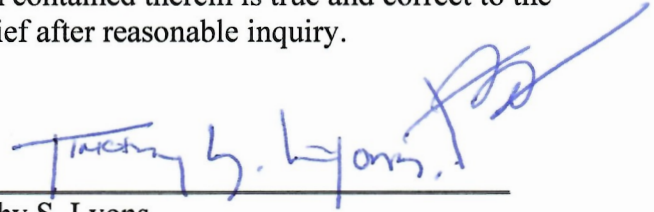
16  A.     Yes, it does.

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<sup>3</sup> See generally Application, Case No. 2023-00159.

## VERIFICATION

The undersigned, Timothy S. Lyons, being duly sworn, deposes and says he is a partner at ScottMadden, 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.



Timothy S. Lyons

State of Vermont )

County of Chittenden )

Case No. 2025-00257

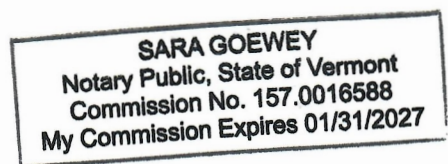
Subscribed and sworn to before me, a Notary Public in and before said County and State, by Timothy S. Lyons, on 8-11-25. Chittenden VT



Notary Public

My Commission Expires 01-31-27

Notary ID Number 157.0016588



### *Summary of Qualifications*

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before more than 30 U.S. and Canadian regulatory agencies. Tim holds a bachelor's degree from St. Anselm College, a master's degree in economics from The Pennsylvania State University, and a master's degree in business administration from Babson College.

### *Areas of Specialization*

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

### *Capabilities*

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

### *Articles and Speeches*

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." **American Gas Association**, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." **American Gas Association**, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." **Power & Gas Marketing**, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." **Public Utilities Fortnightly**, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
<b>Regulatory Commission of Alaska</b>			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
<b>Arizona Corporation Commission</b>			
Southwest Gas Corporation	02/24	Docket No. G-01551A-23-0341	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
<b>Arkansas Public Service Commission</b>			
Summit Utilities, Inc.	01/24	Docket No. 23-079-U	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (The Empire District Electric Company)	2/23	Docket No. 22-085-U	Sponsored testimony supporting the class cost of service, rate design, bill impact studies, and revenue decoupling for a general rate case proceeding.
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
<b>California Public Utilities Commission</b>			
Liberty Utilities (CalPeco Electric)	9/24	Application No. 24-09-010	Sponsored testimony supporting the marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (Apple Valley Water)	01/24	Application No. 24-01-0003	Sponsored testimony supporting rate design studies for a general rate case proceeding.
Liberty Utilities (Park Water)	01/24	Application No. 24-01-0002	Sponsored testimony supporting rate design studies for a general rate case proceeding.
Bear Valley Electric Service, Inc.	10/22	Application No. 22-08-010	Sponsored testimony supporting marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (CalPeco Electric)	5/21	Application No. 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California, and South Lake Tahoe jurisdictions)	8/19	Application No. 19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
<b>Colorado Public Utilities Commission</b>			
Colorado Natural Gas (Summit Utilities)	01/24	Proceeding No. 23A-0570G	Sponsored the Fully Distributed Cost (FDC) study in support of a Cost Assignment and Allocation Manual (CAAM) application.
<b>Connecticut Public Utilities Regulatory Authority</b>			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures, and analysis.
<b>Delaware Public Service Commission</b>			
Artesian Water Company	04/25	Docket No. 25-0346	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Tidewater Utilities, Inc	08/24	Docket No. 24-0991	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Artesian Water Company	04/23	Docket No. 23-0601	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
<b>Illinois Commerce Commission</b>			
Ameren Illinois Company d/b/a Ameren Illinois	6/24	Docket 22-0487/ 23-0082/ 24-0238 (cons.)	Sponsored rebuttal testimony supporting a marginal cost study for a Multi-Year Integrated Grid Plan (Grid Plan) proceeding.
Liberty Utilities (Midstates Natural Gas)	12/23	Docket No. 23-0380	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Ameren Illinois Company d/b/a Ameren Illinois	1/23	Docket No. 22-0487	Sponsored testimony supporting a Multi-Year Integrated Grid Plan (Grid Plan). Prepared research and analysis evaluating the reasonableness of the Grid Plan through comparison to how other electric utilities have responded to the changing energy landscape.
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
<b>Iowa Utilities Board</b>			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
<b>Kansas Corporation Commission</b>			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
<b>Kentucky Public Service Commission</b>			
Kentucky Utilities Company	05/25	Case No 2025-00113	Sponsored testimony supporting cost of service and rate design studies for a general rate case proceeding.
Louisville Gas and Electric Company	05/25	Case No 2025-00114	Sponsored testimony supporting cost of service and rate design studies for a general rate case proceeding.
Bluegrass Water Utility (Central States Water Company)	02/23	Case No. 2022-00432	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
<b>Maine Public Utilities Commission</b>			
Maine Water Company	12/24	Docket No. 2024-00378	Sponsored testimony supporting a two-phased approach to consolidate or unify rate schedules for 10 water utility divisions.
Maine Water Company	10/24	Docket No. 2024-00291	Sponsored testimony supporting the class cost of service, rate design, and bill impact studies for a general rate case proceeding for the Camden and Rockland Division.
Calpine Corporation and Casco Bay Energy Company	10/24	Docket No. 2024-00137	Sponsored testimony regarding ratemaking treatment of Net Energy Billing stranded cost rate design.
Northern Utilities, Inc. d/b/a Unutil	05/23	Docket No. 2023-00051	Sponsored testimony supporting a marginal cost study, class cost of service study, rate design and customer bill impact for a general rate case proceeding.
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unutil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unutil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
<b>Maryland Public Service Commission</b>			
The Potomac Edison Company (FirstEnergy)	03/23	Case No. 9695	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.



Sponsor	Date	Docket No.	Subject
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
<b>Massachusetts Department of Public Utilities</b>			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings, and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
<b>Michigan Public Service Commission</b>			
DTE Energy	04/25	Docket No. U-21860	Sponsored testimony regarding DTE Energy's use of constant dollar averaging to develop its cost forecasts.
Lansing Board of Water & Light and Michigan State University	04/25	Docket No. U-21806	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/24	Docket No. U-21490	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/23	Docket No. U-21308	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/22	Docket No. U-21148	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
<b>Minnesota Public Utilities Commission</b>			

Sponsor	Date	Docket No.	Subject
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE) adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changes in financial market conditions.
<b>Missouri Public Service Commission</b>			
The Empire District Electric Company	11/24	Docket No. ER-2024-0261	Sponsored testimony supporting the class cost of service, rate design, bill impact, and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	11/24	Docket No. GR-2024-0107	Sponsored testimony supporting the class cost of service, rate design, bill impact, and lead-lag studies for a general rate case proceeding.
Liberty Utilities (Missouri Water)	03/24	Docket No. WR-2024-0104	Sponsored testimony supporting lead-lag study for a general rate case proceeding.
Liberty Utilities (Midstates Natural Gas)	02/24	Docket No. GR-2024-0106	Sponsored testimony supporting the class cost of service, rate design, bill impact, and lead-lag studies for a general rate case proceeding.
Confluence Rivers Utility Operating Company	12/22	Case No. WR-2023-0006/ SR-2023-0007	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
<b>Nevada Public Utilities Commission</b>			
Southwest Gas Corporation	09/23	Docket No. 23-09012	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
<b>New Hampshire Public Utilities Commission</b>			
Unitil Energy Systems, Inc.	05/25	Docket No. DE 25-025	Sponsored testimony supporting a marginal cost study, class cost of service study, rate design, customer bill impacts, and revenue decoupling for a general rate case proceeding.
Unitil (Northern Utilities, Inc.)	08/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	04/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
<b>New Jersey Board of Public Utilities</b>			
Middlesex Water Company	07/25	Docket No. WR25060372	Sponsored testimony supporting the class cost of service, rate design, and customer bill impacts for a general rate case proceeding.
Elizabethtown Gas Company	02/24	Docket No. GR24020158	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Jersey Central Power and Light Company (FirstEnergy)	03/23	Docket No. ER23030144	Sponsored testimony supporting the class cost of service and Lead/Lag studies for a general rate case proceeding.
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
<b>New Mexico Public Regulation Commission</b>			
New Mexico Gas Company, Inc.	06/25	Advice Notice No. 109 in Case No. 23-00255-UT	Sponsored testimony supporting the Weather Normalization Adjustment Mechanism.
New Mexico Gas Company, Inc.	12/24	Advice Notice No. 105	Sponsored testimony supporting changes in Rule No. 16 – Line Extension Policy.
New Mexico Gas Company, Inc.	07/24	Case No. 18-00038-UT	Sponsored testimony supporting the Weather Normalization Adjustment Mechanism.
New Mexico Gas Company, Inc.	09/23	Case No. 23-00255-UT	Sponsored testimony supporting the class cost of service, rate design, bill impact and weather normalization adjustment mechanisms for a general rate case proceeding.
<b>New York Public Service Commission</b>			
New York Power Authority	09/04	Case No. 04-E-0572	Sponsored testimony evaluating Con Edison's class cost of service study.

Sponsor	Date	Docket No.	Subject
<b>Corporation Commission of Oklahoma</b>			
Summit Utilities Oklahoma	06/25	Cause No. PUD 2025-000028	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The proposed rate design included a three-year phase-in of the proposed rate increase.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
<b>Ohio Public Utilities Commission</b>			
Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company	06/24	Case Nos. 24-0468-EL-AIR, 24-0469-EL-ATA, 24-0470-EL-AAM, 24-0471-EL-UNC	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
<b>Pennsylvania Public Utility Commission</b>			
FirstEnergy Pennsylvania Electric Company	04/24	Docket No. R-2024-3047068	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
<b>Rhode Island Public Utilities Commission</b>			
Providence Gas Company	09/00 01/97 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	08/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	11/95	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	07/94	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Providence Gas Company	07/93	Docket No. 2076/2082	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.

Sponsor	Date	Docket No.	Subject
<b>Railroad Commission of Texas</b>			
Texas Gas Service Company – Central-Gulf, West North, and Rio Grande Valley Service Areas	06/25	Case No. 00028202	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Central-Gulf Service Area	06/24	Case No. 00017471	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gas Division	10/23	Case No. 00015513	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/23	Case No. 00014399	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – West Texas, North Texas, and Borger/Skellytown Service Areas	06/22	Case No. 00009896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
<b>Public Utility Commission of Texas</b>			
CenterPoint Energy Houston Electric, LLC	03/24	Docket No. 56211	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
<b>Vermont Public Utilities Commission</b>			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by \$90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
<b>Virginia State Corporation Commission</b>			

Sponsor	Date	Docket No.	Subject
Rappahannock Electric Cooperative	3/25	Case No. PUR-2025-00048	Sponsored testimony supporting a new Large Power-Dedicated Facilities (LP-DF) rate schedule
Rappahannock Electric Cooperative	8/24	Case No. PUR-2024-00132	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.
Shenandoah Valley Electric Cooperative	01/24	Case No. PUR-2023-00207	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.
American Electric Power - Appalachian Power Company	03/23	Case No. PUR-2023-00002	Sponsored testimony supporting the Lead/Lag study for the 2023 triennial review of base rates, terms, and conditions.
Rappahannock Electric Cooperative	10/22	Case No. PUR-2022-00160	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms, and conditions.
<b>West Virginia Public Service Commission</b>			
American Electric Power - Appalachian Power Company and Wheeling Power Company	11/24	Case No. 24-0854-E-42T	Sponsored testimony supporting the lead-lag study for a general rate case proceeding.
Monongahela Power Company and The Potomac Edison Company (FirstEnergy)	06/23	Case No. 23-0460-E-42T	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
<b>Nova Scotia Utility and Review Board</b>			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.
<b>Ontario Energy Board</b>			
Toronto Hydro-Electric System Limited	11/23	Docket No. EB-2023-0195	Sponsored evidence supporting Toronto Hydro's Custom Rate Framework. Prepared research and analysis evaluating the appropriateness of the Rate Framework in the context of how other electric utility ratemaking practices have responded to developments in the energy industry.
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals.
<b>Commission of Canada Energy Regulator</b>			
Trans-Northern Pipelines, Inc.	06/23	Docket No. RH-001-2023	Sponsored evidence related to application for approval of incentive tolls.



Kentucky Power Company  
2025 Lead-Lag Study  
Working Capital Requirement  
Summary

Line	Description	Test Year Expenses	Average Daily Expenses	Revenue Lag	Ref.	Expense Lead	Ref.	(Lead)/Lag Days	Working Capital Requirement
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	<b>Operations and Maintenance Expenses</b>								
2	Fuel - Coal and Oil	\$ -	\$ -	1.44	A	(12.82)	B	(11.38)	\$ -
3	Fuel - Gas	-	-	1.44	A	(40.80)	B	(39.36)	-
4	Purchased Power	-	-	1.44	A	(29.66)	D	(28.22)	-
5	Payroll	-	-	1.44	A	(24.46)	C	(23.02)	-
6	Incentive Award (CIP)	-	-	1.44	A	(256.00)	C	(254.56)	-
7	Savings Plan and Benefits	-	-	1.44	A	(28.75)	C	(27.31)	-
8	Other O&M - Excluding Payroll	-	-	1.44	A	(19.82)	D	(18.38)	-
9	<b>Federal Income Tax</b>	\$ -	\$ -	1.44	A	(37.50)	E	(36.06)	\$ -
10	<b>State Income Tax</b>	-	-	1.44	A	(37.50)	F	(36.06)	-
11	<b>Taxes Other Than Income Taxes</b>								
12	Property Tax	\$ -	\$ -	1.44	A	(365.90)	G	(364.46)	\$ -
13	Federal Insurance Contributions Act (FICA) Taxes	-	-	1.44	A	(27.31)	H	(25.87)	-
14	Federal Unemployment Taxes	-	-	1.44	A	(30.09)	H	(28.65)	-
15	State Unemployment Taxes - Kentucky	-	-	1.44	A	(30.07)	H	(28.63)	-
16	State Unemployment Taxes - West Virginia	-	-	1.44	A	(30.45)	H	(29.01)	-
17	Utility Gross Receipts License Tax (UGRLT)	-	-	1.44	A	(34.87)	I	(33.43)	-
18	Sales and Use Tax	-	-	1.44	A	(40.13)	J	(38.69)	-
19	KY Sales and Use Tax - Energy Exemption Annual Return	-	-	1.44	A	(34.88)	K	(33.44)	-
20	Federal Excise Taxes	-	-	1.44	A	(76.24)	L	(74.80)	-
21	Local Franchise Fee	-	-	1.44	A	(47.96)	L	(46.52)	-
22	Local Street Lighting Fee	-	-	1.44	A	(207.72)	L	(206.28)	-
23	<b>Interest on Long-Term Debt</b>	\$ -	\$ -	1.44	A	(82.99)	M	(81.55)	\$ -
24	<b>Cash Working Capital Requirement</b>	\$ -	\$ -	-					\$ -

Kentucky Power Company  
2025 Lead-Lag Study  
Revenue Lag

Line	Description	Revenue Lag	Reference
1	Service Period Lag		
2	Billing Lag	1.44	A-1
3	<u>Composite Revenue Lag</u>	<u>1.44</u>	



Kentucky Power Company  
2025 Lead-Lag Study  
Fuel

Line	Fuel Type	Payments	(Lead)/ Lag Days	Dollar Days	Reference
1	Coal	\$ 117,222,132	(12.96)	\$ (1,519,442,954)	WP (B) - Fuel
2	Oil	6,908,737	(10.35)	(71,489,519)	WP (B) - Fuel
3	Coal and Oil	\$ 124,130,869	(12.82)	\$ (1,590,932,472)	
4	Gas	\$ 40,754,344	(40.80)	\$ (1,662,833,104)	WP (B) - Fuel
5	Total	\$ 164,885,212	(19.73)	\$ (3,253,765,576)	

Kentucky Power Company  
2025 Lead-Lag Study  
Payroll

Line	Description	Amount	(Lead)/Lag Days	Weighted Dollar Days	Reference
1	Payroll	\$ 38,891,435	(24.46)	\$ (951,238,681)	C-1
2	Incentive Award (CIP)	1,929,422	(256.00)	(493,931,948)	C-2
3	Savings Plan and Benefits	11,463,312	(28.75)	(329,545,705)	C-3

Kentucky Power Company  
2025 Lead-Lag Study  
O&M Expense (Including Purchased Power)

Line	Description	Amount	Total (Lead)/Lag Days	Weighted Dollar Days	Reference
1	Purchased Power	\$ 127,936,606	(29.66)	\$ (3,794,620,565)	D-1
2	Other O&M - Excluding Payroll	62,563,726	(19.82)	(1,240,325,529)	D-2
3	<u>Total</u>	<u>\$ 190,500,332</u>	<u>(26.43)</u>	<u>\$ (5,034,946,094)</u>	

Kentucky Power Company  
2025 Lead-Lag Study  
Other O&M

Line	Business Unit	Amount	Total (Lead)/Lag	Weighted Dollar Days	Reference
1	AEP Service Corp Billing - BU 117 - Gen	\$ 9,060,290	(18.21)	\$ (164,967,157)	D-2a
2	AEP Service Corp Billing - BU 110 - Dist	23,228,691	(18.19)	(422,495,262)	D-2a
3	AEP Service Corp Billing - BU 180 - Trans	24,990,060	(18.23)	(455,648,219)	D-2a
4	AEP Inter-Company Billings - BU 117 - Gen	\$ 289,009	(19.71)	\$ (5,696,150)	D-2b
5	AEP Inter-Company Billings - BU 110 - Dist	1,835,964	(19.43)	(35,676,946)	D-2b
6	AEP Inter-Company Billings - BU 180 - Trans	481,326	(20.50)	(9,868,369)	D-2b
7	BU 117 - Gen	\$ 597,400	(12.19)	\$ (7,285,205)	D-2c
8	BU 110 - Dist	1,499,830	(71.85)	(107,764,493)	D-2d
9	BU 180 - Trans	581,156	(53.21)	(30,923,728)	D-2e
10	Total Other O&M Lead Days	\$ 62,563,726	(19.82)	\$ (1,240,325,529)	

Kentucky Power Company  
2025 Lead-Lag Study  
Federal Income Tax

Line	Service Period Start	Service Period End	Midpoint of Service	Payment Date	(Lead)/Lag	Percent of Total Taxes	Weighted Days
1	1/1/2024	12/31/2024	(183.00)	4/15/2024	77.00	25%	19.25
2	1/1/2024	12/31/2024	(183.00)	6/15/2024	16.00	25%	4.00
3	1/1/2024	12/31/2024	(183.00)	9/15/2024	(76.00)	25%	(19.00)
4	1/1/2024	12/31/2024	(183.00)	12/15/2024	(167.00)	25%	(41.75)
5	Total						(37.50)

Kentucky Power Company  
2025 Lead-Lag Study  
State Income Tax

Line	Service Period Start	Service Period End	Midpoint of Service	Payment Date	(Lead)/Lag	Percent of Total Taxes	Weighted Days
1	1/1/2024	12/31/2024	(183.00)	4/15/2024	77.00	25%	19.25
2	1/1/2024	12/31/2024	(183.00)	6/15/2024	16.00	25%	4.00
3	1/1/2024	12/31/2024	(183.00)	9/15/2024	(76.00)	25%	(19.00)
4	1/1/2024	12/31/2024	(183.00)	12/15/2024	(167.00)	25%	(41.75)
5	Total						(37.50)

Kentucky Power Company  
2025 Lead-Lag Study  
Property Tax

Line	Description	Service Period Start	Service Period End	Midpoint of Service	Check Reconcile Date	Payment (Lead)/Lag Days	Tax Amount	Weighted Dollar Days	Composite (Lead)/Lag Days
1	FIRST NATIONAL TITLE & ESCROW LLC	1/1/2025	12/31/2025	(182.50)	2024-07-25	341.50	\$ (1,179)	\$ (402,758)	
2	HAZARD, CITY OF	1/1/2025	12/31/2025	(182.50)	2024-09-27	277.50	2,981	827,105	
3	SHERIFF PERRY COUNTY	1/1/2025	12/31/2025	(182.50)	2024-10-23	251.50	11,079	2,786,338	
4	KENTUCKY STATE TREASURER	1/1/2025	12/31/2025	(182.50)	2025-02-19	132.50	19,057	2,525,018	
5	KENTUCKY STATE TREASURER	1/1/2025	12/31/2025	(182.50)	2025-02-19	132.50	892	118,129	
6	KENTUCKY STATE TREASURER	1/1/2025	12/31/2025	(182.50)	2025-02-19	132.50	14,599	1,934,370	
7	SHERIFF BOYD COUNTY	1/1/2024	12/31/2024	(183.00)	2024-07-24	(23.00)	3,992	(91,818)	
8	SHERIFF LAWRENCE COUNTY	1/1/2024	12/31/2024	(183.00)	2024-07-25	(24.00)	2	(53)	
9	SHERIFF FRANKLIN COUNTY	1/1/2024	12/31/2024	(183.00)	2024-08-02	(32.00)	2	(70)	
10	SHERIFF PERRY COUNTY	1/1/2024	12/31/2024	(183.00)	2024-08-08	(38.00)	18,061	(686,304)	
11	WEST VIRGINIA AUDITORS OFFICE	1/1/2024	12/31/2024	(183.00)	2024-09-03	(64.00)	1,392,081	(89,093,213)	
12	WEST VIRGINIA AUDITORS OFFICE	1/1/2024	12/31/2024	(183.00)	2024-09-03	(64.00)	1,326	(84,864)	
13	SHERIFF MARSHALL COUNTY	1/1/2024	12/31/2024	(183.00)	2024-09-10	(71.00)	63,292	(4,493,762)	
14	HAZARD, CITY OF	1/1/2024	12/31/2024	(183.00)	2024-09-27	(88.00)	46	(4,023)	
15	KENTUCKY STATE TREASURER	1/1/2024	12/31/2024	(183.00)	2024-10-08	(99.00)	11,190	(1,107,761)	
16	KENTUCKY STATE TREASURER	1/1/2024	12/31/2024	(183.00)	2024-10-08	(99.00)	523	(51,826)	
17	KENTUCKY STATE TREASURER	1/1/2024	12/31/2024	(183.00)	2024-10-08	(99.00)	8,572	(848,635)	
18	SHERIFF GREENUP COUNTY	1/1/2024	12/31/2024	(183.00)	2024-10-23	(114.00)	2,185	(249,097)	
19	SHERIFF PERRY COUNTY	1/1/2024	12/31/2024	(183.00)	2024-10-23	(114.00)	152	(17,344)	
20	SHERIFF GREENUP COUNTY	1/1/2024	12/31/2024	(183.00)	2024-10-23	(114.00)	6,335	(722,135)	
21	SHERIFF PERRY COUNTY	1/1/2024	12/31/2024	(183.00)	2024-10-23	(114.00)	3,641	(415,113)	
22	SHERIFF BOYD COUNTY	1/1/2024	12/31/2024	(183.00)	2024-10-24	(115.00)	50	(5,750)	
23	SHERIFF HENDERSON COUNTY	1/1/2024	12/31/2024	(183.00)	2024-10-31	(122.00)	770	(93,984)	
24	SHERIFF BOYD COUNTY	1/1/2024	12/31/2024	(183.00)	2024-11-04	(126.00)	3,896	(490,885)	
25	SHERIFF FRANKLIN COUNTY	1/1/2024	12/31/2024	(183.00)	2024-11-13	(135.00)	2	(286)	
26	FLATWOODS, CITY OF	1/1/2024	12/31/2024	(183.00)	2024-11-26	(148.00)	566	(83,706)	
27	FLATWOODS, CITY OF	1/1/2024	12/31/2024	(183.00)	2024-11-26	(148.00)	0	(16)	
28	SHERIFF LAWRENCE COUNTY	1/1/2024	12/31/2024	(183.00)	2025-01-17	(200.00)	2	(428)	
29	KENTUCKY STATE TREASURER	1/1/2024	12/31/2024	(183.00)	2025-02-19	(233.00)	2,126,026	(495,364,065)	
30	KENTUCKY STATE TREASURER	1/1/2024	12/31/2024	(183.00)	2025-02-19	(233.00)	941,229	(219,306,455)	
31	KENTUCKY STATE TREASURER	1/1/2024	12/31/2024	(183.00)	2025-02-19	(233.00)	1,356,360	(316,031,843)	
32	WEST VIRGINIA AUDITORS OFFICE	1/1/2024	12/31/2024	(183.00)	2025-03-03	(245.00)	1,326	(324,870)	
33	WEST VIRGINIA AUDITORS OFFICE	1/1/2024	12/31/2024	(183.00)	2025-03-03	(245.00)	1,392,081	(341,059,953)	
34	PIKEVILLE INDEPENDENT SCHOOLS	1/1/2023	12/31/2023	(182.50)	2024-07-09	(373.50)	6,006	(2,243,286)	
35	PIKEVILLE INDEPENDENT SCHOOLS	1/1/2023	12/31/2023	(182.50)	2024-07-09	(373.50)	82,845	(30,942,566)	
36	PIKEVILLE INDEPENDENT SCHOOLS	1/1/2023	12/31/2023	(182.50)	2024-07-09	(373.50)	6,489	(2,423,642)	
37	BREATHITT COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	16,919	(6,336,338)	
38	BREATHITT COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	0	(56)	
39	BREATHITT COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	177,199	(66,361,168)	
40	SHERIFF LEWIS COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	53,291	(19,957,386)	
41	SHERIFF LEWIS COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	5,157	(1,931,199)	
42	SHERIFF JOHNSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	103,266	(38,672,945)	
43	SHERIFF JOHNSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	36,944	(13,835,678)	
44	SHERIFF JOHNSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-10	(374.50)	1	(330)	
45	SHERIFF LESLIE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-11	(375.50)	197,650	(74,217,590)	
46	SHERIFF LESLIE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-11	(375.50)	88,766	(33,331,704)	
47	SHERIFF LESLIE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-11	(375.50)	17	(6,564)	
48	SHERIFF CLAY COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-07-11	(375.50)	5,109	(1,918,456)	
49	SHERIFF CLAY COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-07-11	(375.50)	1,766	(663,268)	
50	SHERIFF BELL COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-11	(375.50)	1,550	(581,890)	
51	SHERIFF BELL COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-11	(375.50)	47	(17,510)	
52	PAINTSVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-15	(379.50)	1,826	(692,865)	
53	PAINTSVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-15	(379.50)	45,473	(17,256,909)	
54	PAINTSVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-15	(379.50)	1,296	(491,832)	
55	SHERIFF ROBERTSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-15	(379.50)	15,515	(5,887,810)	
56	SHERIFF BRACKEN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-16	(380.50)	6,982	(2,656,719)	
57	SHERIFF OWEN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-23	(387.50)	26,919	(10,431,078)	
58	GRAYSON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-23	(387.50)	4,373	(1,694,545)	
59	GRAYSON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-23	(387.50)	0	(12)	
60	GRAYSON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-23	(387.50)	18	(6,816)	
61	WORTHINGTON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	1,608	(624,514)	
62	WORTHINGTON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	2,617	(1,016,817)	
63	SHERIFF ROWAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	8,104	(3,148,295)	
64	SHERIFF ROWAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	0	(23)	
65	SHERIFF ROWAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	25,428	(9,878,941)	
66	WEST LIBERTY, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	2,056	(798,830)	
67	WEST LIBERTY, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	(0)	23	
68	SHERIFF CARTER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	145,110	(56,375,177)	
69	SHERIFF CARTER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	0	(51)	
70	SHERIFF CARTER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	14,864	(5,774,722)	
71	SHERIFF CARROLL COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	5,073	(1,970,744)	
72	SHERIFF HARRISON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	8,302	(3,225,238)	
73	SHERIFF BOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	136,246	(52,931,470)	
74	SHERIFF BOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	0	(8)	
75	SHERIFF BOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	513,557	(199,517,054)	
76	JACKSON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	4,086	(1,587,504)	
77	JACKSON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	33	(12,731)	
78	ASHLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	130,706	(50,779,188)	
79	ASHLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	0	(101)	
80	ASHLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	2,357	(915,757)	
81	SHERIFF PIKE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	424,568	(164,944,851)	
82	SHERIFF PIKE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	9	(3,598)	
83	SHERIFF PIKE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	947,176	(367,977,775)	
84	PIKEVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	13,077	(5,080,348)	
85	PIKEVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	25	(9,806)	
86	PIKEVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	20,465	(7,950,614)	
87	SHERIFF MAGOFFIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	6,765	(2,628,164)	
88	SHERIFF MAGOFFIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	103,083	(40,047,718)	
89	SHERIFF MAGOFFIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-24	(388.50)	0	(101)	
90	SOUTH SHORE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	65	(25,275)	
91	SOUTH SHORE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	11	(4,117)	
92	SHERIFF MASON COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	0	(129)	
93	SHERIFF MASON COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	23,947	(9,327,477)	
94	SHERIFF LAWRENCE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	79,964	(31,146,095)	
95	SHERIFF LAWRENCE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	11,029	(4,295,866)	

Kentucky Power Company  
2025 Lead-Lag Study  
Property Tax

Line	Description	Service Period Start	Service Period End	Midpoint of Service	Check Reconcile Date	Payment (Lead)/Lag Days	Tax Amount	Weighted Dollar Days	Composite (Lead)/Lag Days
96	SHERIFF LAWRENCE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	297,391	(115,833,826)	
97	SHERIFF PERRY COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	201,935	(78,653,784)	
98	SHERIFF PERRY COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	3	(1,215)	
99	SHERIFF PERRY COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-25	(389.50)	330,995	(128,922,568)	
100	PRESTONSBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-26	(390.50)	11,150	(4,354,180)	
101	PRESTONSBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-26	(390.50)	0	(55)	
102	PRESTONSBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-26	(390.50)	987	(385,412)	
103	WURLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-29	(393.50)	1,896	(745,938)	
104	WURLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-29	(393.50)	3,051	(1,200,403)	
105	KNOTT COUNTY SHERIFF	1/1/2023	12/31/2023	(182.50)	2024-07-29	(393.50)	113,217	(44,551,035)	
106	KNOTT COUNTY SHERIFF	1/1/2023	12/31/2023	(182.50)	2024-07-29	(393.50)	0	(87)	
107	KNOTT COUNTY SHERIFF	1/1/2023	12/31/2023	(182.50)	2024-07-29	(393.50)	235,344	(92,607,970)	
108	SHERIFF MORGAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-30	(394.50)	8,283	(3,267,726)	
109	SHERIFF MORGAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-30	(394.50)	48,850	(19,271,250)	
110	SHERIFF MARTIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-30	(394.50)	222,425	(87,746,465)	
111	SHERIFF MARTIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-30	(394.50)	0	(8)	
112	SHERIFF MARTIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-30	(394.50)	8,726	(3,442,573)	
113	RUSSELL, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	26,336	(10,416,074)	
114	RUSSELL, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	2,305	(911,434)	
115	SHERIFF TRIMBLE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	21,872	(8,650,238)	
116	SHERIFF GREENUP COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	390,398	(154,402,239)	
117	SHERIFF GREENUP COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	0	(142)	
118	SHERIFF GREENUP COUNTY	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	5,970	(2,361,016)	
119	JACKSON INDEPENDENT SCHOOL DISTRICT	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	1,212	(479,338)	
120	JACKSON INDEPENDENT SCHOOL DISTRICT	1/1/2023	12/31/2023	(182.50)	2024-07-31	(395.50)	4,819	(1,905,994)	
121	SHERIFF HENRY COUNTY	1/1/2023	12/31/2023	(182.50)	2024-08-01	(396.50)	5,884	(2,332,891)	
122	SHERIFF PENDLETON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-08-02	(397.50)	16,644	(6,616,022)	
123	SHERIFF FRANKLIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-08-02	(397.50)	277	(110,096)	
124	SHERIFF FRANKLIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-08-02	(397.50)	135	(53,818)	
125	SHERIFF FRANKLIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-08-02	(397.50)	77	(30,588)	
126	SHERIFF PERRY COUNTY	1/1/2023	12/31/2023	(182.50)	2024-08-08	(403.50)	6,122	(2,470,094)	
127	SHERIFF KNOX COUNTY	1/1/2023	12/31/2023	(182.50)	2024-08-21	(416.50)	15,113	(6,294,719)	
128	HAZARD, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-08-28	(423.50)	11,817	(5,004,351)	
129	HAZARD, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-08-28	(423.50)	23,009	(9,744,307)	
130	BELLEFONTE CITY OF KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-09-03	(429.50)	1,257	(539,830)	
131	BELLEFONTE CITY OF KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-09-03	(429.50)	84	(36,069)	
132	SHERIFF FLOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-09-03	(429.50)	155,639	(66,846,753)	
133	SHERIFF FLOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-09-03	(429.50)	466,557	(200,386,309)	
134	HINDMAN, TOWN OF	1/1/2023	12/31/2023	(182.50)	2024-09-06	(432.50)	1,062	(459,402)	
135	HINDMAN, TOWN OF	1/1/2023	12/31/2023	(182.50)	2024-09-06	(432.50)	(0)	26	
136	SHERIFF-TREASURER WAYNE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-09-16	(442.50)	2,016	(891,885)	
137	SHERIFF OWSLEY COUNTY	1/1/2023	12/31/2023	(182.50)	2024-09-25	(451.50)	1,161	(524,413)	
138	SHERIFF OWSLEY COUNTY	1/1/2023	12/31/2023	(182.50)	2024-09-25	(451.50)	(0)	27	
139	KENTUCKY STATE TREASURER	1/1/2023	12/31/2023	(182.50)	2024-10-08	(464.50)	1,248,334	(579,851,083)	
140	KENTUCKY STATE TREASURER	1/1/2023	12/31/2023	(182.50)	2024-10-08	(464.50)	552,660	(256,710,352)	
141	KENTUCKY STATE TREASURER	1/1/2023	12/31/2023	(182.50)	2024-10-08	(464.50)	796,411	(369,932,779)	
142	SHERIFF CARTER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-22	(478.50)	141,614	(67,762,175)	
143	SHERIFF CARTER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-22	(478.50)	0	(62)	
144	SHERIFF CARTER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-22	(478.50)	14,506	(6,941,198)	
145	SHERIFF TRIMBLE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-22	(478.50)	21,345	(10,213,453)	
146	SHERIFF MORGAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-22	(478.50)	8,084	(3,868,070)	
147	SHERIFF MORGAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-22	(478.50)	47,673	(22,811,449)	
148	SHERIFF MASON COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	22,903	(10,982,003)	
149	SHERIFF MASON COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	0	(139)	
150	SHERIFF JOHNSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	36,054	(17,288,032)	
151	SHERIFF JOHNSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	1	(412)	
152	SHERIFF JOHNSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	100,778	(48,322,912)	
153	SHERIFF CLAY COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	1,724	(826,624)	
154	SHERIFF CLAY COUNTY KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	4,986	(2,390,720)	
155	SHERIFF GREENUP COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	380,992	(182,685,774)	
156	SHERIFF GREENUP COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	0	(168)	
157	SHERIFF GREENUP COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	5,826	(2,793,452)	
158	SHERIFF HARRISON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	8,102	(3,884,794)	
159	SHERIFF LEWIS COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	5,032	(2,413,007)	
160	SHERIFF LEWIS COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-23	(479.50)	52,007	(24,937,366)	
161	WEST LIBERTY, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	2,007	(964,200)	
162	WEST LIBERTY, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	(0)	29	
163	GREENUP, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	180	(86,682)	
164	GREENUP, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	0	(67)	
165	SHERIFF LESLIE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	86,628	(41,624,586)	
166	SHERIFF LESLIE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	17	(8,197)	
167	SHERIFF LESLIE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	192,888	(92,682,785)	
168	SHERIFF ROBERTSON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-24	(480.50)	15,141	(7,275,202)	
169	WURLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-25	(481.50)	1,850	(890,842)	
170	WURLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-25	(481.50)	2,977	(1,433,392)	
171	WORTHINGTON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-25	(481.50)	1,569	(755,329)	
172	WORTHINGTON, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-25	(481.50)	2,554	(1,229,895)	
173	RUSSELL, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-28	(484.50)	25,702	(12,452,614)	
174	RUSSELL, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-28	(484.50)	2,249	(1,089,626)	
175	PAINTSVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-28	(484.50)	44,377	(21,500,763)	
176	PAINTSVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-28	(484.50)	1,265	(612,781)	
177	PAINTSVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-28	(484.50)	1,782	(863,258)	
178	SOUTH SHORE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-29	(485.50)	63	(30,732)	
179	SOUTH SHORE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-29	(485.50)	10	(5,025)	
180	PIKEVILLE INDEPENDENT SCHOOLS	1/1/2023	12/31/2023	(182.50)	2024-10-30	(486.50)	80,849	(39,333,019)	
181	PIKEVILLE INDEPENDENT SCHOOLS	1/1/2023	12/31/2023	(182.50)	2024-10-30	(486.50)	6,333	(3,080,844)	
182	PIKEVILLE INDEPENDENT SCHOOLS	1/1/2023	12/31/2023	(182.50)	2024-10-30	(486.50)	5,861	(2,851,586)	
183	FLATWOODS, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-30	(486.50)	283	(137,660)	
184	FLATWOODS, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-10-30	(486.50)	(0)	10	
185	WAYLAND, TOWN OF	1/1/2023	12/31/2023	(182.50)	2024-10-31	(487.50)	824	(401,642)	
186	WAYLAND, TOWN OF	1/1/2023	12/31/2023	(182.50)	2024-10-31	(487.50)	2,280	(1,111,559)	
187	SHERIFF GRANT COUNTY	1/1/2023	12/31/2023	(182.50)	2024-10-31	(487.50)	37,404	(18,234,275)	
188	SHERIFF BOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-04	(491.50)	132,963	(65,351,546)	
189	SHERIFF BOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-04	(491.50)	0	(10)	
190	SHERIFF BOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-04	(491.50)	501,185	(246,332,211)	



Kentucky Power Company  
2025 Lead-Lag Study  
Property Tax

Line	Description	Service Period Start	Service Period End	Midpoint of Service	Check Reconcile Date	Payment (Lead)/Lag Days	Tax Amount	Weighted Dollar Days	Composite (Lead)/Lag Days
191	SHERIFF BRACKEN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-06	(493.50)	6,814	(3,362,679)	
192	JENKINS, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-11-06	(493.50)	13,303	(6,564,887)	
193	JENKINS, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-11-06	(493.50)	247	(122,047)	
194	SHERIFF LETCHER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-07	(494.50)	731,738	(361,844,258)	
195	SHERIFF LETCHER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-07	(494.50)	1	(297)	
196	SHERIFF LETCHER COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-07	(494.50)	55,976	(27,679,900)	
197	SHERIFF CARROLL COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-12	(499.50)	4,852	(2,423,324)	
198	SHERIFF PIKE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-12	(499.50)	414,340	(206,962,735)	
199	SHERIFF PIKE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-12	(499.50)	9	(4,510)	
200	SHERIFF PIKE COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-12	(499.50)	924,356	(461,715,902)	
201	ASHLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-11-12	(499.50)	127,557	(63,714,647)	
202	ASHLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-11-12	(499.50)	0	(125)	
203	ASHLAND, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-11-12	(499.50)	2,300	(1,149,005)	
204	SHERIFF FRANKLIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-13	(500.50)	270	(135,290)	
205	SHERIFF FRANKLIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-13	(500.50)	132	(66,136)	
206	SHERIFF FRANKLIN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-13	(500.50)	75	(37,583)	
207	SHERIFF OWEN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-15	(502.50)	26,270	(13,200,861)	
208	LOUISA, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-11-22	(509.50)	4,139	(2,108,887)	
209	LOUISA, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-11-22	(509.50)	13	(6,573)	
210	SHERIFF ROWAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-25	(512.50)	7,908	(4,052,917)	
211	SHERIFF ROWAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-25	(512.50)	0	(31)	
212	SHERIFF ROWAN COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-25	(512.50)	24,816	(12,718,267)	
213	SHERIFF PENDLETON COUNTY	1/1/2023	12/31/2023	(182.50)	2024-11-26	(513.50)	16,243	(8,340,832)	
214	BELLEFONTE CITY OF KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-11-29	(516.50)	1,227	(633,523)	
215	BELLEFONTE CITY OF KENTUCKY	1/1/2023	12/31/2023	(182.50)	2024-11-29	(516.50)	82	(42,348)	
216	HINDMAN, TOWN OF	1/1/2023	12/31/2023	(182.50)	2024-12-02	(519.50)	1,037	(538,519)	
217	HINDMAN, TOWN OF	1/1/2023	12/31/2023	(182.50)	2024-12-02	(519.50)	(0)	31	
218	PIKEVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-06	(523.50)	12,506	(6,547,142)	
219	PIKEVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-06	(523.50)	24	(12,637)	
220	PIKEVILLE, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-06	(523.50)	19,572	(10,246,199)	
221	SHERIFF BELL COUNTY	1/1/2023	12/31/2023	(182.50)	2024-12-09	(526.50)	46	(23,966)	
222	SHERIFF BELL COUNTY	1/1/2023	12/31/2023	(182.50)	2024-12-09	(526.50)	1,512	(796,210)	
223	KNOTT COUNTY SHERIFF	1/1/2023	12/31/2023	(182.50)	2024-12-09	(526.50)	110,490	(58,172,838)	
224	KNOTT COUNTY SHERIFF	1/1/2023	12/31/2023	(182.50)	2024-12-09	(526.50)	0	(116)	
225	KNOTT COUNTY SHERIFF	1/1/2023	12/31/2023	(182.50)	2024-12-09	(526.50)	229,674	(120,923,529)	
226	PRESTONSBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-16	(533.50)	10,882	(5,805,387)	
227	PRESTONSBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-16	(533.50)	0	(75)	
228	PRESTONSBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-16	(533.50)	963	(513,830)	
229	OLIVE HILL, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-16	(533.50)	209	(111,357)	
230	OLIVE HILL, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-16	(533.50)	1	(608)	
231	ALLEN, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-18	(535.50)	1,269	(679,421)	
232	ALLEN, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-18	(535.50)	1	(386)	
233	ALLEN, CITY OF	1/1/2023	12/31/2023	(182.50)	2024-12-18	(535.50)	41	(21,881)	
234	MARTIN, CITY OF	1/1/2023	12/31/2023	(182.50)	2025-01-06	(554.50)	2,068	(1,146,445)	
235	MARTIN, CITY OF	1/1/2023	12/31/2023	(182.50)	2025-01-06	(554.50)	84	(46,839)	
236	SHERIFF FLOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2025-01-16	(564.50)	151,973	(85,788,759)	
237	SHERIFF FLOYD COUNTY	1/1/2023	12/31/2023	(182.50)	2025-01-16	(564.50)	455,567	(257,167,713)	
238	SHERIFF LAWRENCE COUNTY	1/1/2023	12/31/2023	(182.50)	2025-01-17	(565.50)	78,037	(44,130,127)	
239	SHERIFF LAWRENCE COUNTY	1/1/2023	12/31/2023	(182.50)	2025-01-17	(565.50)	10,763	(6,086,748)	
240	SHERIFF LAWRENCE COUNTY	1/1/2023	12/31/2023	(182.50)	2025-01-17	(565.50)	290,227	(164,123,193)	
241	SHERIFF KNOX COUNTY	1/1/2023	12/31/2023	(182.50)	2025-02-05	(584.50)	14,749	(8,620,954)	
242	WHITESBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2025-02-07	(586.50)	11,625	(6,818,039)	
243	WHITESBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2025-02-07	(586.50)	184	(107,646)	
244	WHITESBURG, CITY OF	1/1/2023	12/31/2023	(182.50)	2025-02-07	(586.50)	104	(61,078)	
245	SHERIFF WOLFE COUNTY	1/1/2023	12/31/2023	(182.50)	2025-03-13	(620.50)	14,973	(9,290,635)	
246	WHEELWRIGHT, CITY OF	1/1/2023	12/31/2023	(182.50)	2025-03-21	(628.50)	1,559	(979,662)	
247	WHEELWRIGHT, CITY OF	1/1/2023	12/31/2023	(182.50)	2025-03-21	(628.50)	3,230	(2,030,124)	
248	Total						\$ 21,925,221	\$ (8,022,487,654)	(365.90)

Kentucky Power Company  
2025 Lead-Lag Study  
Payroll Taxes

Line	Description	Amount	(Lead) Lag Days	Weighted Dollar- Days	Reference
1	FICA Taxes	\$ 9,447	(27.31)	\$ (257,971)	H-1
2	FUTA Taxes	11,753	(30.09)	(353,658)	H-2
3	SUTA Taxes - Kentucky	10,257	(30.07)	(308,429)	H-3
4	SUTA Taxes - West Virginia	1,004	(30.45)	(30,581)	H-3
5	<u>Total Payroll Taxes</u>	<u>\$ 32,461</u>	<u>(29.29)</u>	<u>\$ (950,639)</u>	

Kentucky Power Company  
2025 Lead-Lag Study  
Utility Gross Receipts License Tax (UGRLT)

Line	Service Period Start	Service Period End	Midpoint of Service Period	Date Paid	Amount Paid	Days Lead	Weighted Dollar- Days
1	4/1/2024	4/30/2024	(15.00)	5/20/2024	\$ 950,513	(35.00)	\$ (33,267,950)
2	5/1/2024	5/31/2024	(15.50)	6/20/2024	922,943	(35.50)	(32,764,476)
3	6/1/2024	6/30/2024	(15.00)	7/19/2024	970,193	(34.00)	(32,986,569)
4	7/1/2024	7/31/2024	(15.50)	8/20/2024	1,102,230	(35.50)	(39,129,158)
5	8/1/2024	8/31/2024	(15.50)	9/20/2024	1,136,889	(35.50)	(40,359,569)
6	9/1/2024	9/30/2024	(15.00)	10/18/2024	1,044,372	(33.00)	(34,464,292)
7	10/1/2024	10/31/2024	(15.50)	11/20/2024	909,722	(35.50)	(32,295,123)
8	11/1/2024	11/30/2024	(15.00)	12/20/2024	880,152	(35.00)	(30,805,331)
9	12/1/2024	12/31/2024	(15.50)	1/21/2025	1,243,652	(36.50)	(45,393,288)
10	1/1/2025	1/31/2025	(15.50)	2/20/2025	1,548,339	(35.50)	(54,966,018)
11	2/1/2025	2/28/2025	(14.00)	3/20/2025	1,479,094	(34.00)	(50,289,188)
12	3/1/2025	3/31/2025	(15.50)	4/18/2025	1,268,861	(33.50)	(42,506,839)
13	Total				\$ 13,456,960	(34.87)	\$ (469,227,801)

Kentucky Power Company  
2025 Lead-Lag Study  
Sales and Use Tax

Line	Service Period Start	Service Period End	Midpoint of Service Period	Date Paid	Amount Paid	Days Lead	Weighted Dollar- Days
1	4/1/2024	4/30/2024	(15.00)	5/24/2024	\$ 786,420	(39.00)	\$ (30,670,375)
2	5/1/2024	5/31/2024	(15.50)	6/25/2024	998,967	(40.50)	(40,458,175)
3	6/1/2024	6/30/2024	(15.00)	7/25/2024	682,147	(40.00)	(27,285,876)
4	7/1/2024	7/31/2024	(15.50)	8/23/2024	479,197	(38.50)	(18,449,095)
5	8/1/2024	8/31/2024	(15.50)	9/25/2024	1,079,428	(40.50)	(43,716,826)
6	9/1/2024	9/30/2024	(15.00)	10/25/2024	750,717	(40.00)	(30,028,688)
7	10/1/2024	10/31/2024	(15.50)	11/25/2024	525,978	(40.50)	(21,302,127)
8	11/1/2024	11/30/2024	(15.00)	12/24/2024	883,404	(39.00)	(34,452,772)
9	12/1/2024	12/31/2024	(15.50)	1/27/2025	966,222	(42.50)	(41,064,422)
10	1/1/2025	1/31/2025	(15.50)	2/25/2025	1,051,106	(40.50)	(42,569,792)
11	2/1/2025	2/28/2025	(14.00)	3/25/2025	988,754	(39.00)	(38,561,418)
12	3/1/2025	3/31/2025	(15.50)	4/25/2025	976,803	(40.50)	(39,560,507)
13	Total				\$ 10,169,144	(40.13)	\$ (408,120,072)

Kentucky Power Company  
2025 Lead-Lag Study  
Kentucky Sales and Use Tax - Energy Exemption Annual Return

Line	Service Period Start	Service Period End	Midpoint of Service Period	Date Paid	Amount Paid	Days Lead	Weighted Dollar- Days
1	4/1/2024	4/30/2024	(15.00)	5/20/2024	\$ 1,649	(35.00)	\$ (57,726)
2	5/1/2024	5/31/2024	(15.50)	6/20/2024	1,649	(35.50)	(58,551)
3	6/1/2024	6/30/2024	(15.00)	7/19/2024	1,649	(34.00)	(56,077)
4	7/1/2024	7/31/2024	(15.50)	8/20/2024	1,649	(35.50)	(58,551)
5	8/1/2024	8/31/2024	(15.50)	9/20/2024	1,649	(35.50)	(58,551)
6	9/1/2024	9/30/2024	(15.00)	10/18/2024	1,649	(33.00)	(54,427)
7	10/1/2024	10/31/2024	(15.50)	11/20/2024	1,649	(35.50)	(58,551)
8	11/1/2024	11/30/2024	(15.00)	12/20/2024	1,649	(35.00)	(57,726)
9	12/1/2024	12/31/2024	(15.50)	1/21/2025	1,649	(36.50)	(60,200)
10	1/1/2025	1/31/2025	(15.50)	2/20/2025	1,541	(35.50)	(54,722)
11	2/1/2025	2/28/2025	(14.00)	3/20/2025	1,541	(34.00)	(52,410)
12	3/1/2025	3/31/2025	(15.50)	4/18/2025	1,541	(33.50)	(51,639)
13	Total				\$ 19,468	(34.88)	\$ (679,128)

Kentucky Power Company  
2025 Lead-Lag Study  
Other Taxes

Line	Service Period Start	Service Period End	Service Lead	Date Paid	Amount Paid	Check Float	Total Lead	Weighted Dollar- Days
<b>Federal Excise Taxes</b>								
1	4/1/2024	6/30/2024	(45.50)	7/31/2024	\$ 965	-	(76.50)	\$ (73,787)
2	7/1/2024	9/30/2024	(46.00)	10/31/2024	-	-	(77.00)	-
3	10/1/2024	12/31/2024	(46.00)	1/31/2025	1,073	-	(77.00)	(82,643)
4	1/1/2025	3/31/2025	(45.00)	4/30/2025	872	-	(75.00)	(65,381)
5	Total Federal Excise Taxes				\$ 2,910		(76.24)	\$ (221,811)
<b>Local Franchise Fee</b>								
6	4/1/2024	4/30/2024	(15.00)	5/20/2024	\$ 53,916	(12.73)	(47.73)	\$ (2,573,260)
7	5/1/2024	5/31/2024	(15.50)	6/20/2024	52,257	(12.73)	(48.23)	(2,520,231)
8	6/1/2024	6/30/2024	(15.00)	7/20/2024	525,118	(12.73)	(47.73)	(25,062,447)
9	7/1/2024	7/31/2024	(15.50)	8/20/2024	60,465	(12.73)	(48.23)	(2,916,078)
10	8/1/2024	8/31/2024	(15.50)	9/20/2024	68,400	(12.73)	(48.23)	(3,298,754)
11	9/1/2024	9/30/2024	(15.00)	10/20/2024	640,144	(12.73)	(47.73)	(30,552,336)
12	10/1/2024	10/31/2024	(15.50)	11/20/2024	57,167	(12.73)	(48.23)	(2,757,004)
13	11/1/2024	11/30/2024	(15.00)	12/20/2024	47,958	(12.73)	(47.73)	(2,288,903)
14	12/1/2024	12/31/2024	(15.50)	1/20/2025	527,552	(12.73)	(48.23)	(25,442,406)
15	1/1/2025	1/31/2025	(15.50)	2/20/2025	72,816	(12.73)	(48.23)	(3,511,730)
16	2/1/2025	2/28/2025	(14.00)	3/20/2025	81,727	(12.73)	(46.73)	(3,818,901)
17	3/1/2025	3/31/2025	(15.50)	4/20/2025	644,391	(12.73)	(48.23)	(31,077,219)
18	Total Local Franchise Fee				\$ 2,831,913		(47.96)	\$ (135,819,269)

Kentucky Power Company  
2025 Lead-Lag Study  
Other Taxes

Line	Service Period Start	Service Period End	Service Lead	Date Paid	Amount Paid	Check Float	Total Lead	Weighted Dollar- Days
<b>Local Street Lighting Fee</b>								
19	4/1/2023	3/31/2024	(183.00)	4/12/2024	\$ 18,459	(12.73)	(207.73)	\$ (3,834,419)
20	5/1/2023	4/30/2024	(183.00)	5/12/2024	3,213	(12.73)	(207.73)	(667,517)
21	6/1/2023	5/31/2024	(183.00)	6/12/2024	23,548	(12.73)	(207.73)	(4,891,601)
22	7/1/2023	6/30/2024	(183.00)	7/12/2024	41,628	(12.73)	(207.73)	(8,647,186)
23	8/1/2023	7/31/2024	(183.00)	8/12/2024	19,769	(12.73)	(207.73)	(4,106,473)
24	10/1/2023	9/30/2024	(183.00)	10/12/2024	21,104	(12.73)	(207.73)	(4,383,951)
25	12/1/2023	11/30/2024	(183.00)	12/12/2024	2,350	(12.73)	(207.73)	(488,145)
26	1/1/2024	12/31/2024	(183.00)	1/12/2025	19,894	(12.73)	(207.73)	(4,132,543)
27	3/1/2024	2/28/2025	(182.50)	3/12/2025	1,550	(12.73)	(207.23)	(321,136)
28	<b>Total Local Street Lighting Fee</b>				\$ 151,515		(207.72)	\$ (31,472,971)
29	<b>Total Other Taxes</b>				\$ 2,986,337		(56.09)	\$ (167,514,051)

Kentucky Power Company  
2025 Lead-Lag Study  
Long-Term Debt

Line	Description	Service Period Start	Service Period End	Midpoint of Service Period	Interest	Weighting Factor	Weighted Lead Time
1	Senior Notes (Private Placement)	10/2/2023	4/1/2024	(91.00)	\$ 2,508,000	3.429%	(3.12)
2	\$150M Bank Term Loan (CIBC)	1/19/2024	4/18/2024	(45.00)	2,384,839	3.260%	(1.47)
3	Senior Notes (Public)	11/10/2023	5/15/2024	(93.50)	13,489,583	18.441%	(17.24)
4	\$150M Bank Term Loan (CIBC)	4/18/2024	5/20/2024	(16.00)	849,185	1.161%	(0.19)
5	Senior Notes (Private Placement)	12/1/2023	6/3/2024	(92.50)	2,109,375	2.884%	(2.67)
6	WV Economic Dev. Authority, Series 2014A (Mitchell)	12/1/2023	6/3/2024	(92.50)	1,527,500	2.088%	(1.93)
7	Intercompany Notes (paid to AEP Inc.)	3/12/2024	6/12/2024	(46.00)	330,625	0.452%	(0.21)
8	Senior Notes (Private Placement)	12/18/2023	6/18/2024	(91.50)	1,204,500	1.647%	(1.51)
9	Senior Notes (Private Placement)	12/18/2023	6/18/2024	(91.50)	2,439,000	3.334%	(3.05)
10	\$150M Bank Term Loan (CIBC)	5/20/2024	6/20/2024	(15.50)	822,802	1.125%	(0.17)
11	Senior Notes (Private Placement)	1/2/2024	7/1/2024	(90.50)	1,732,000	2.368%	(2.14)
12	\$150M Bank Term Loan (CIBC)	6/20/2024	7/22/2024	(16.00)	851,823	1.164%	(0.19)
13	Intercompany Notes (paid to AEP Inc.)	6/12/2024	8/20/2024	(34.50)	249,806	0.341%	(0.12)
14	Senior Notes (Private Placement)	3/12/2024	9/12/2024	(92.00)	1,017,250	1.391%	(1.28)
15	Senior Notes (Private Placement)	3/12/2024	9/12/2024	(92.00)	670,000	0.916%	(0.84)
16	Senior Notes (Private Placement)	3/12/2024	9/12/2024	(92.00)	2,846,250	3.891%	(3.58)
17	Senior Notes (Private Placement)	3/12/2024	9/12/2024	(92.00)	1,133,000	1.549%	(1.42)
18	Senior Notes (Private Placement)	4/1/2024	9/30/2024	(91.00)	2,508,000	3.429%	(3.12)
19	\$150M Bank Term Loan (CIBC)	7/22/2024	10/22/2024	(46.00)	2,427,271	3.318%	(1.53)
20	Senior Notes (Public)	5/15/2024	11/15/2024	(92.00)	13,125,000	17.943%	(16.51)
21	\$150M Bank Term Loan (CIBC)	10/22/2024	11/22/2024	(15.50)	750,337	1.026%	(0.16)
22	Senior Notes (Private Placement)	6/3/2024	12/2/2024	(91.00)	2,109,375	2.884%	(2.62)
23	WV Economic Dev. Authority, Series 2014A (Mitchell)	6/3/2024	12/2/2024	(91.00)	1,527,500	2.088%	(1.90)
24	Senior Notes (Private Placement)	6/18/2024	12/18/2024	(91.50)	1,204,500	1.647%	(1.51)
25	Senior Notes (Private Placement)	6/18/2024	12/18/2024	(91.50)	2,439,000	3.334%	(3.05)
26	\$150M Bank Term Loan (CIBC)	11/22/2024	12/20/2024	(14.00)	658,599	0.900%	(0.13)
27	Senior Notes (Private Placement)	7/1/2024	12/30/2024	(91.00)	1,732,000	2.368%	(2.15)
28	\$150M Bank Term Loan (CIBC)	12/20/2024	1/17/2025	(14.00)	632,364	0.864%	(0.12)
29	\$150M Bank Term Loan (CIBC)	1/17/2025	2/18/2025	(16.00)	713,473	0.975%	(0.16)
30	Senior Notes (Private Placement)	9/12/2024	3/12/2025	(90.50)	670,000	0.916%	(0.83)
31	Senior Notes (Private Placement)	9/12/2024	3/13/2025	(91.00)	2,846,250	3.891%	(3.54)
32	Senior Notes (Private Placement)	9/12/2024	3/14/2025	(91.50)	1,133,000	1.549%	(1.42)
33	Senior Notes (Private Placement)	9/30/2024	3/31/2025	(91.00)	2,508,000	3.429%	(3.12)
34	Total				\$ 73,150,206		(82.99)



**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 Certain Regulatory And Accounting	)	Case No. 2025-00257
Treatments; and (4) All Other Required Approvals	)	
And Relief	)	

**DIRECT TESTIMONY OF**  
**JOHN WOLFRAM**  
**ON BEHALF OF KENTUCKY POWER COMPANY**

**DIRECT TESTIMONY OF  
JOHN WOLFRAM ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

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**EXHIBITS**

<b><u>EXHIBIT</u></b>	<b><u>DESCRIPTION</u></b>
EXHIBIT JW-1	Qualifications
EXHIBIT JW-2	Zero-Intercept Study

**DIRECT TESTIMONY OF  
JOHN WOLFRAM ON BEHALF OF  
KENTUCKY POWER COMPANY  
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

**CASE NO. 2025-00257**

**I. INTRODUCTION**

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

2   A.   My name is John Wolfram. I am the Principal of Catalyst Consulting LLC. My  
3       business address is 3308 Haddon Road, Louisville, Kentucky, 40241.

4   **Q.   ON WHOSE BEHALF ARE YOU TESTIFYING?**

5   A.   I am testifying on behalf of Kentucky Power Company (“Company”).

6   **Q.   BRIEFLY DESCRIBE YOUR EDUCATION AND WORK EXPERIENCE.**

7   A.   I received a Bachelor of Science degree in Electrical Engineering from the  
8       University of Notre Dame in 1990 and a Master of Science degree in Electrical  
9       Engineering from Drexel University in 1997. I founded Catalyst Consulting LLC  
10      in June 2012. I have developed cost-of-service studies and rates for numerous  
11      electric utilities, including investor-owned utilities, electric distribution  
12      cooperatives, generation and transmission cooperatives, and municipal utilities. I  
13      have performed economic analyses, rate mechanism reviews, special rate designs,  
14      and wholesale formula rate reviews. From March 2010 through May 2012, I was a  
15      Senior Consultant with The Prime Group, LLC. I have also been employed by the  
16      parent companies of Louisville Gas and Electric Company (“LG&E”) and  
17      Kentucky Utilities Company (“KU”), by the PJM Interconnection, and by the  
18      Cincinnati Gas & Electric Company. In some instances, I provide consulting

1 services on a contract basis through another consulting firm, as I am in this case  
2 with Clearspring Energy Advisors. A more detailed description of my  
3 qualifications is included in Exhibit JW-1.

4 **Q. HAVE YOU EVER TESTIFIED BEFORE THE KENTUCKY PUBLIC**  
5 **SERVICE COMMISSION (“COMMISSION”)?**

6 A. Yes. I have testified in numerous regulatory proceedings before this Commission  
7 and have been involved in Commission matters nearly continuously since 1999. A  
8 listing of my testimony in other proceedings is included in Exhibit JW-1.

## **II. PURPOSE OF TESTIMONY**

9 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

10 A. The purpose of my testimony is to describe and present the results of a  
11 zero-intercept study performed at the Company’s request.

12 **Q. ARE YOU SPONSORING ANY EXHIBITS?**

13 A. Yes. I have prepared the following exhibits to support my testimony:

14 Exhibit JW-1 – Qualifications

15 Exhibit JW-2 – Zero-Intercept Study

## **III. ZERO-INTERCEPT THEORY**

16 **Q. WHAT IS A ZERO-INTERCEPT STUDY?**

17 A. *The Electric Utility Cost Allocation Manual* published by the National Association  
18 of Regulatory Utility Commissioners (“NARUC”) dated January 1992 (“NARUC  
19 CAM”) identifies the zero-intercept (or “minimum intercept”) as one of two  
20 standard methodologies for classifying distribution fixed costs. The NARUC CAM

1 states that certain distribution costs should be functionally classified as  
2 customer-related and demand-related in a cost-of-service study.

3 Costs classified as *demand-related* vary with the capacity needs of  
4 customers, such as the amount of transmission or distribution equipment necessary  
5 to meet a customer's needs, or other elements that are related to facility size.  
6 Distribution substation transformers are examples of costs typically classified as  
7 demand costs. Costs classified as *customer-related* include costs incurred to serve  
8 customers regardless of the quantity of electric energy purchased or the peak  
9 requirements of the customers and vary with the number of customers. These  
10 include the cost of the minimum system necessary to provide a customer with  
11 access to the electric grid. The zero-intercept method is used to divide distribution  
12 costs related to poles, overhead conductor, underground conductor, and line  
13 transformers between the demand-related and customer-related categories.

14 Stated differently, the zero-intercept method provides a rational basis for  
15 separating the cost of a device or facility between its customer and demand  
16 components. Theoretically, the customer-related costs are associated with the  
17 portion of facilities that do not require any capacity or size – one might call this the  
18 “zero-sized” facility cost – and then the rest of the facility costs are demand-related,  
19 because they are associated with the portion of facilities that do require capacity or  
20 non-zero size.

21 **Q. HOW DOES THE ZERO-INTERCEPT METHOD GENERALLY WORK?**

22 A. The zero-intercept method uses linear regression to determine the theoretical cost  
23 for connecting a customer of zero size to the grid. Linear regression is a statistical

analysis used to predict the value of a variable based on the value of another variable; it attempts to model the relationship between two variables by fitting a linear equation to observed data. In this application, the linear regression attempts to predict the cost of a theoretically “zero-sized” facility (*e.g.*, pole, conductor, transformer) based on the sizes and costs of existing facilities on the utility books. This method is less subjective than other approaches and is preferred when the necessary data are available. With the zero-intercept method, a zero-size conductor or line transformer is the absolute minimum system, or the smallest amount of facility investment needed to serve a customer regardless of their demand and thus is customer-related. Any costs above that minimum must be related to demand.

**Q. WHAT IS THE THEORY BEHIND THE ZERO-INTERCEPT METHOD?**

A. The theory behind the zero-intercept method is that a linear relationship exists between the unit cost of conductor or line transformers and the load flow capability of the plant, which is proportionate to the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

**y** is the unit cost of the conductor or transformer,

**x** is the size of the conductor (MCM) or transformer (kVA), and

**a, b** are the coefficients representing the intercept and slope, respectively,

it can be determined that, theoretically, the unit cost of a pole or foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying

capability) is a, the zero-intercept. The zero-intercept is essentially the cost component of poles, conductor or transformers that is invariant to the size and load carrying capability of the plant.

For most electric utilities, the feet of conductor and number of transformers on the system are not uniformly distributed over all sizes of wire and transformer. In other words, a utility might have more of size 1/0 conductor than it has of size 2/0 conductor, or it might have more 10 kVA transformers than 15 kVA transformers. The number of facilities of various sizes are not the same, so each size must be weighted by quantity in the linear regression analysis. For this reason, it is necessary to use a *weighted* regression analysis, instead of a standard least-squares analysis, in the determination of the zero-intercept. Without performing a weighted regression analysis, all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

Using a weighted regression analysis, the cost and size of each type of conductor, pole or transformer is weighted by the number of feet of installed conductor or the number of poles or transformers. In a weighted regression analysis, the following weighted sum of squared differences is minimized, where  $w$  is the weighting factor for each size of conductor or transformer, and  $y$  is the observed value and  $\hat{y}$  is the predicted value of the dependent variable:

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

1   **Q.   DOES THE NARUC CAM PROVIDE INSTRUCTIONS FOR THE**  
2       **ZERO-INTERCEPT ANALYSIS?**

3   A.   Yes. The NARUC CAM provides the following instructions for overhead  
4       conductor, underground conductor, and transformers on pages 92–94. In the  
5       NARUC CAM, the terms “zero-intercept” and “minimum intercept” are  
6       synonymous. The instructions are summarized as follows:

7       **Account 364 – Poles, Towers, and Fixtures**

8           Determine minimum intercept of pole cost using cost per foot by  
9           classes and heights of poles weighted by the number of poles in each  
10          category and developing a cost for the utility’s minimum size pole.

11       **Account 365 – Overhead Conductors and Devices**

12          Determine minimum intercept of conductor cost per foot using cost  
13          per foot by size and type of conductor weighted by feet or  
14          investment in each category and developing a cost for the utility’s  
15          minimum size conductor.

16       **Account 366 and 367 – Underground Conduit, and Underground**  
17       **Conductors and Devices**

18          Determine minimum intercept of cable cost per foot using cost per  
19          foot by size and type of cable weighted by feet of investment in each  
20          category.



**Account 368 – Line Transformers**

Determine zero-intercept of transformer cost using cost per transformer by type, weighted by number for each category. Only single-phase sizes up to and including 50 kVA should be used.

**Q. WHAT KIND OF RESULTS DOES THE ZERO-INTERCEPT ANALYSIS PROVIDE?**

A. The zero-intercept analysis provides the theoretical cost per unit for a zero-sized facility. In other words, it provides the cost of a zero-foot pole, the cost per length for conduit of zero cross-sectional area, and the cost for a transformer of zero kVA capacity. These must be positive numbers for the results to be meaningful; if the linear regression produces a negative zero-intercept, then the cost per unit would be less than zero, which is unreasonable. If the zero-intercept is positive, it can be multiplied by the total number of units (*i.e.*, number of poles, length of conductor, or number of transformers) to determine the theoretical total cost of zero-sized facilities. This cost in dollars is the share of total facility costs that is customer-related; any remaining costs are demand-related. The two resultant dollar amounts can then be used to develop a percentage share for customer and a percentage share for demand, and these percentages can be used in a cost-of-service study or other applications to split facility costs between customer and demand classifications.

1   **Q.    HAVE YOU PREPARED EXHIBITS SHOWING THE RESULTS OF THE**  
2       **ZERO-INTERCEPT ANALYSIS?**

3   A.    Yes. The zero-intercept analysis for poles, overhead conductor, underground  
4       conductor, and line transformers are included in Exhibit JW-2.

#### **IV.    ZERO-INTERCEPT RESULTS**

5   **Q.    PLEASE DESCRIBE THE PROCESS UNDERTAKEN TO PERFORM THE**  
6       **ZERO-INTERCEPT STUDY.**

7   A.    The study was performed by using records provided by the Company. These  
8       records include cost and quantity for poles in Account 364, conductor in Accounts  
9       365 and 367, and transformers in Account 368. This data was then input to a linear  
10       regression calculation to identify the zero-intercept for each of the respective  
11       accounts. For poles, the size of the facility is the pole height from Company  
12       records. For conductor, the size is the cross-sectional area of the conductor in kcmil  
13       (where 1 kcmil = 0.5067 mm<sup>2</sup>). This information is available in electrical industry  
14       handbooks. For transformers, the size is the transformer kilovolt-amperes (kVA)  
15       from Company records.

16   **Q.    DID THE ZERO-INTERCEPT ANALYSIS PROVIDE A REASONABLE**  
17       **SOLUTION FOR ACCOUNT 364 – POLES?**

18   A.    No. The linear regression provided a zero-intercept that is less than zero, which is  
19       unreasonable. This is a very common outcome for the zero-intercept analysis for  
20       poles, which is why some electric utilities in Kentucky (including KU and LG&E,  
21       along with numerous distribution cooperatives) split pole costs between demand  
22       and customer in base rate cases using the zero-intercept study results for overhead

1 conductor, since the poles and overhead conductor are mutually dependent (*i.e.*,  
2 overhead conductor requires poles, and poles are only required for overhead  
3 conductor).

4 **Q. DID THE ZERO-INTERCEPT ANALYSIS PROVIDE A REASONABLE**  
5 **SOLUTION FOR THE OTHER ACCOUNTS?**

6 A. Yes. The zero-intercept results for Account 365 – Overhead Conductor, Account  
7 367 – Underground Conductor, and Account 368 – Transformers were all  
8 mathematically sound and provide a reasonable basis for separating the cost of  
9 these facilities between their customer and demand components. These results are  
10 provided in Exhibit JW-2.

11 **Q. HOW DO THE RESULTS PROVIDED IN EXHIBIT JW-2 COMPARE TO**  
12 **THE RESULTS OF SIMILAR ZERO-INTERCEPT ANALYSES YOU**  
13 **HAVE REVIEWED OR PREPARED FOR OTHER ELECTRIC**  
14 **UTILITIES?**

15 A. The results of the zero-intercept analysis in the instant case are generally consistent  
16 with the results of other studies I have reviewed or prepared for other electric  
17 utilities; they are neither extreme nor unconventional relative to other utilities with  
18 which I am familiar.

19 **V. CONCLUSION**

20 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

21 A. The zero-intercept study provided in Exhibit JW-2 provides a mathematically  
22 sound and rational basis for separating the costs for overhead conductor,  
23 underground conductor, and line transformers between their customer and demand  
24 components. It is also reasonable to apply the zero-intercept study results for

1           overhead conductor to poles, because the two are interdependent and because the  
2           Commission has accepted this numerous times in electric rate filings. The study is  
3           consistent with industry standards and adheres to the process accepted by the  
4           Commission many times over many years. The study and its results should be  
5           accepted by the Commission in the instant case.

6   **Q.    DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

7   A.    Yes.

**ANNE L FOYE**  
Notary Public - State at Large  
Kentucky  
My Commission Expires Jun. 12, 2029  
Notary ID KYNP29156

## **JOHN WOLFRAM**

### **Summary of Qualifications**

Provides consulting services to electric utilities regarding utility rate and regulatory filings, cost of service studies, wholesale and retail rate designs, tariffs and special contracts, formula rates, energy policy, and other matters.

### **Employment**

**CATALYST CONSULTING LLC**  
Principal

June 2012 – Present

**THE PRIME GROUP, LLC**  
Senior Consultant

March 2010 – May 2012

**LG&E and KU, Louisville, KY**

1997 - 2010

(Louisville Gas & Electric Company and Kentucky Utilities Company)

Director, Customer Service & Marketing (2006 - 2010)

Manager, Regulatory Affairs (2001 - 2006)

Lead Planning Engineer, Generation Planning (1998 - 2001)

Power Trader, LG&E Energy Marketing (1997 - 1998)

**PJM INTERCONNECTION, LLC, Norristown, PA**

1990 - 1993; 1994 - 1997

Project Lead – PJM OASIS Project

Chair, Data Management Working Group

**CINCINNATI GAS & ELECTRIC COMPANY, Cincinnati, OH**

1993 - 1994

Electrical Engineer - Energy Management System

### **Education**

Bachelor of Science Degree in Electrical Engineering, University of Notre Dame, 1990

Master of Science Degree in Electrical Engineering, Drexel University, 1997

Leadership Louisville, 2006

### **Associations**

Senior Member, Institute of Electrical and Electronics Engineers ("IEEE") & Power Engineering Society

### **Articles**

"FERC Formula Rate Resurgence" *Public Utilities Fortnightly*, Vol. 158, No. 9, July 2020, 34-37.

"Economic Development Rates: Public Service or Piracy?" *IAEE Energy Forum*, International Association for Energy Economics, 2016 Q1 (January 2016), 17-20.

### **Presentations**

"Utilities Driving Economic Development" panel discussion at the Mid-America Regulatory Conference, Jun. 2025.

"Utility Rates for the Modern Grid" presented as APPA Online Virtual Course, Apr. 2025

“Evolving Rate Structures: Adapting Co-op Rate Pricing Models for the Modern Grid” presented to CFC Independent Borrowers Executive Summit, Nov. 2024

“Aligning Rates with the Modern Grid” presented to APPA Business & Financial Conference, Sep 2024.

“Cooperative Rate Cases” presented to Kentucky Electric Coops Fall Managers’ Meeting, Oct. 2023.

“New Developments in Kentucky Rate Filings” presented to Electric Cooperatives Accountants’ Association Summer Meeting, Jun. 2022.

“Avoiding Shock: Communicating Rate Changes” presented to APPA Business & Financial Conference, Sep. 2020.

“Revisiting Rate Design Strategies” presented to APPA Public Power Forward Summit, Nov. 2019.

“Utility Rates at the Crossroads” presented to APPA Business & Financial Conference, Sep. 2019.

“New Developments in Kentucky Rate Filings” presented to Electric Cooperatives Accountants’ Association Summer Meeting, Jun. 2019.

“Electric Rates: New Approaches to Ratemaking” presented to CFC Statewide Workshop, Jan. 2019.

“The Great Rate Debate: Residential Demand Rates” presented to CFC Forum, Jun. 2018.

“Benefits of Cost of Service Studies” presented to Tri-State Electric Cooperatives Accountants’ Association Spring Meeting, Apr. 2017.

“Proper Design of Utility Rate Incentives” presented to APPA/Area Development’s Public Power Consultants Forum, Mar. 2017.

“Utility Hot Topics and Economic Development” presented to APPA/Area Development’s Public Power Consultants Forum, Mar. 2017.

“Emerging Rate Designs” presented to CFC Independent Borrowers Executive Summit, Nov. 2016.

“Optimizing Economic Development” presented to Grand River Dam Authority Municipal Customer Annual Meeting, Sept. 2016.

“Tomorrow’s Electric Rate Designs, Today” presented to CFC Forum, Jun. 2016.

“Reviewing Rate Class Composition to Support Sound Rate Design” presented to EEI Rate and Regulatory Analysts Group Meeting, May 2016.

“Taking Public Power Economic Development to the Next Level” presented to APPA/Area Development’s Public Power Consultants Forum, Mar. 2016.

“Ratemaking for Environmental Compliance Plans” presented to NARUC Staff Subcommittee on Accounting and Finance Fall Conference, Sep. 2015.

“Top Utility Strategies for Successful Attraction, Retention & Expansion” presented to APPA/Area Development’s Public Power Consultants Forum, Mar. 2015.

“Economic Development and Load Retention Rates” presented to NARUC Staff Subcommittee on Accounting and Finance Fall Conference, Sep. 2013.

### **Expert Witness Testimony & Proceedings**

#### **FERC**

Submitted direct testimony for Viridon Path 15, LLC in FERC Docket No. ER25-2707 regarding a proposed wholesale transmission rate.

Submitted direct testimony for Cheyenne Light, Fuel & Power Company in FERC Docket No. ER25-2171 regarding proposed revisions to a Transmission Formula Rate.

Submitted direct testimony for DATC Path 15, LLC in FERC Docket No. ER25-1310 regarding a proposed wholesale transmission rate.

Submitted testimony for Evergy Missouri, Inc., Evergy Metro, Inc., and Evergy Kansas Central, Inc. in FERC Docket Nos. ER25-206, ER25-207, and ER25-208 regarding proposed Wholesale Distribution Access Service rates.

Submitted direct testimony for Black Hills Colorado Electric, LLC in FERC Docket No. ER22-2185 regarding a proposed Transmission Formula Rate.

Submitted testimony for Evergy Kansas Central, Inc. and Evergy Generating, Inc. in FERC Docket Nos. ER22-1974-000, ER22-1975-000 and ER22-1976-000 regarding revised capital structures under transmission and generation formula rates.

Submitted affidavit for Constellation Mystic Power, LLC in FERC Docket No. ER18-1639-000 in response to arguments raised in formal challenges to an informational filing required for a cost-of-service rate for the operation of power plants in ISO New England.

Submitted direct testimony for El Paso Electric Company in FERC Docket No. ER22-282 regarding a proposed Transmission Formula Rate.

Submitted direct testimony for TransCanyon Western Development, LLC in FERC Docket No. ER21-1065 regarding a proposed Transmission Formula Rate.

Submitted direct testimony for Cleco Power LLC in FERC Docket No. ER21-370 regarding a proposed rate schedule for Blackstart Service under Schedule 33 of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

Submitted direct testimony for Constellation Mystic Power, LLC in FERC Docket No. ER18-1639-005 supporting a compliance filing for a cost-of-service rate for compensation for the continued operation of power plants in ISO New England.

Submitted direct testimony for DATC Path 15, LLC in FERC Docket No. ER20-1006 regarding a proposed wholesale transmission rate.

Submitted direct testimony for Tucson Electric Power Company in FERC Docket No. ER19-2019 regarding a proposed Transmission Formula Rate.



Submitted direct testimony for Cheyenne Light, Fuel & Power Company in FERC Docket No. ER19-697 regarding a proposed Transmission Formula Rate.

Supported Kansas City Power & Light in FERC Docket No. ER19-1861-000 regarding revisions to fixed depreciation rates in the KCP&L SPP Transmission Formula Rate.

Supported Westar Energy and Kansas Gas & Electric Company in FERC Docket No. ER19-269-000 regarding revisions to fixed depreciation rates in the Westar SPP Transmission Formula Rate.

Submitted direct testimony for Midwest Power Transmission Arkansas, LLC in FERC Docket No. ER15-2236 regarding a proposed Transmission Formula Rate.

Submitted direct testimony for Kanstar Transmission, LLC in FERC Docket No. ER15-2237 regarding a proposed Transmission Formula Rate.

Supported Westar Energy and Kansas Gas & Electric Company in FERC Docket Nos. FA15-9-000 and FA15-15-000 regarding an Audit of Compliance with Rates, Terms and Conditions of Westar's Open Access Transmission Tariff and Formula Rates, Accounting Requirements of the Uniform System of Accounts, and Reporting Requirements of the FERC Form No. 1.

Submitted direct testimony for Westar Energy in FERC Docket Nos. ER14-804 and ER14-805 regarding proposed revisions to a Generation Formula Rate.

Supported Intermountain Rural Electric Association and Tri-State G&T in FERC Docket No. ER12-1589 regarding revisions to Public Service of Colorado's Transmission Formula Rate.

Supported Intermountain Rural Electric Association in FERC Docket No. ER11-2853 regarding revisions to Public Service of Colorado's Production Formula Rate.

Supported Kansas Gas & Electric Company in FERC Docket No. FA14-3-000 regarding an Audit of Compliance with Nuclear Plant Decommissioning Trust Fund Regulations and Accounting Practices.

Supported LG&E Energy LLC in FERC Docket No. PA05-9-000 regarding an Audit of Code of Conduct, Standards of Conduct, Market-Based Rate Tariff, and MISO's Open Access Transmission Tariff at LG&E Energy LLC.

Submitted remarks and served on expert panel in FERC Docket No. RM01-10-000 on May 21, 2002 in Standards of Conduct for Transmission Providers staff conference, regarding proposed rulemaking on the functional separation of wholesale transmission and bundled sales functions for electric utilities.

### Kansas

Submitted direct and rebuttal testimony for Evergy Metro, Inc. in Docket No. 23-EKCE-775-RTS regarding a jurisdictional cost allocation in a retail rate case.

Submitted report for Westar Energy, Inc. in Docket No. 21-WCNE-103-GIE regarding plans and options for funding the decommissioning trust fund, depreciation expenses, and overall cost recovery in the event of premature closing of the Wolf Creek nuclear plant.

Submitted direct and rebuttal testimony for Westar Energy, Inc. in Docket No. 18-WSEE-328-RTS regarding overall rate design, prior rate case settlement commitments, lighting tariffs, an Electric Transit rate schedule, Electric Vehicle charging tariffs, and tariff general terms and conditions.

Submitted direct and rebuttal testimony for Westar Energy, Inc. in Docket No. 18-KG&E-303-CON regarding the Evaluation, Measurement and Verification (“EM&V”) of an energy efficiency demand response program offered pursuant to a large industrial customer special contract.

Submitted report for Westar Energy, Inc. in Docket No. 18-WCNE-107-GIE regarding plans and options for funding the decommissioning trust fund, depreciation expenses, and overall cost recovery in the event of premature closing of the Wolf Creek nuclear plant.

Submitted direct and rebuttal testimony for Westar Energy, Inc. in Docket No. 15-WSEE-115-RTS regarding rate designs for large customer classes, establishment of a balancing account related to new rate options, establishment of a tracking mechanism for costs related to compliance with mandated cyber and physical security standards, other rate design issues, and revenue allocation.

### Kentucky

Submitted direct testimony on behalf of Clark Energy Cooperative in Case No. 2025-00230 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony on behalf of sixteen distribution cooperative owner-members of East Kentucky Power Cooperative in Case Nos. 2025-00209 through 2021-00222 regarding rate design for the pass-through of a proposed wholesale rate revision.

Submitted direct testimony and responses to data requests on behalf of Farmers R.E.C.C. in Case No. 2025-00107 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony and responses to data requests on behalf of Blue Grass Energy in Case No. 2025-00103 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony and responses to data requests on behalf of Cumberland Valley Electric in Case No. 2024-00388 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct and rebuttal testimony and responses to data requests on behalf of South Kentucky R.E.C.C. in Case No. 2024-00402 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony and responses to data requests on behalf of Shelby Energy Cooperative in Case No. 2024-00351 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony and responses to data requests on behalf of Jackson Energy Cooperative in Case No. 2024-00324 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted responses to data requests on behalf of Big Rivers Electric Corporation in Case No. 2024-00149 regarding the Fuel Adjustment Clause.

Submitted direct testimony, responses to data requests, and rebuttal testimony on behalf of Big Sandy R.E.C.C. in Case No. 2024-00287 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony and responses to data requests on behalf of Licking Valley R.E.C.C. in Case No. 2024-00211 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony, rebuttal testimony, and responses to data requests on behalf of Jackson Purchase Energy Corporation in Case No. 2024-00085 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Adopted direct testimony on behalf of Kentucky Power Company in Case No. 2023-00159 regarding the zero intercept analysis in a base rate case.

Submitted responses to data requests on behalf of Big Rivers Electric Corporation and Kenergy Corp. in Case No. 2023-00312 regarding a Large Industrial Customer Standby Service Tariff.

Submitted direct testimony on behalf of Big Sandy R.E.C.C. in Case No. 2023-00285 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony, rebuttal testimony, and responses to data requests on behalf of Kenergy Corp. in Case No. 2023-00276 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony, rebuttal testimony, and responses to data requests on behalf of Fleming-Mason Energy Corporation in Case No. 2023-00223 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony and responses to data requests on behalf of Shelby Energy Cooperative in Case No. 2023-00213 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony and responses to data requests on behalf of Farmers RECC in Case No. 2023-00158 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony, rebuttal testimony, and responses to data requests on behalf of Taylor County RECC in Case No. 2023-00147 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted tariff worksheets and responses to data requests on behalf of sixteen distribution cooperative owner-members of East Kentucky Power Cooperative in Case No. 2023-00135 regarding rate design for the pass-through of an approved wholesale earning mechanism bill credit.

Submitted direct testimony and responses to data requests on behalf of Big Rivers Electric Corporation in Case No. 2023-00102 regarding a Qualifying Facilities tariff.

Submitted direct testimony on behalf of Big Rivers Electric Corporation and Kenergy Corp. in Case No. 2023-00045 regarding a marginal cost of service study in support of an economic development rate for a special contract.

Submitted direct and rebuttal testimony and responses to data requests on behalf of Jackson Purchase Energy Corporation in Case No. 2021-00358 regarding revenue requirements, adjustments, cost of service and rate design in a base rate case.

Submitted direct and rebuttal testimony and responses to data requests on behalf of Big Rivers Electric Corporation in Case No. 2021-00289 regarding a Large Industrial Customer Standby Service Tariff.

Submitted direct testimony on behalf of Big Rivers Electric Corporation and Jackson Purchase Energy Corporation in Case No. 2021-00282 regarding a marginal cost of service study in support of an economic development rate for a special contract.

Submitted direct testimony, responses to data requests, and rebuttal testimony on behalf of sixteen distribution cooperative owner-members of East Kentucky Power Cooperative in Case Nos. 2021-00104 through 2021-00119 regarding rate design for the pass-through of a proposed wholesale rate revision.

Submitted direct testimony and responses to data requests on behalf of Kenergy Corp. in Case No. 2021-00066 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony on behalf of Big Rivers Electric Corporation in Case No. 2021-00061 regarding two cost of service studies in a review of the Member Rate Stability Mechanism Charge for calendar year 2020.

Submitted direct testimony and responses to data requests on behalf of Licking Valley R.E.C.C. in Case No. 2020-00338 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony and responses to data requests on behalf of Cumberland Valley Electric in Case No. 2020-00264 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony and responses to data requests on behalf of Taylor County R.E.C.C. in Case No. 2020-00278 regarding the cost support and tariff changes for the implementation of a Prepay Metering Program.

Submitted direct testimony and responses to data requests on behalf of Meade County R.E.C.C. in Case No. 2020-00131 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony and responses to data requests on behalf of Clark Energy Cooperative in Case No. 2020-00104 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony and responses to data requests on behalf of Big Rivers Electric Corporation in Case No. 2019-00435 regarding an Environmental Compliance Plan and Environmental Surcharge rate mechanism.

Submitted direct testimony and responses to data requests on behalf of Jackson Energy Cooperative in Case No. 2019-00066 regarding revenue requirements, cost of service and rate design in a streamlined rate case.

Submitted direct testimony and responses to data requests on behalf of Jackson Purchase Energy Corporation in Case No. 2019-00053 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a streamlined rate case.

Submitted direct testimony and data request responses on behalf of Big Rivers Electric Corporation in Case No. 2018-00146 regarding ratemaking issues associated with the anticipated termination of contracts regarding the operation of an electric generating plant owned by the City of Henderson, Kentucky.

Submitted direct testimony on behalf of fifteen distribution cooperative owner-members of East Kentucky Power Cooperative in Case No. 2018-00050 regarding the economic evaluation of and potential cost shift resulting from a proposed member purchased power agreement.

Submitted direct testimony on behalf of Big Sandy R.E.C.C. in Case No. 2017-00374 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a base rate case.

Submitted direct testimony on behalf of Progress Metal Reclamation Company in Kentucky Power Company Case No. 2017-00179 regarding the potential implementation of a Load Retention Rate or revisions to an Economic Development Rate.

Submitted direct testimony on behalf of Kenergy Corp. and Big Rivers Electric Corporation in Case No. 2016-00117 regarding a marginal cost of service study in support of an economic development rate for a special contracts customer.

Submitted rebuttal testimony on behalf of Big Rivers Electric Corporation in Case No. 2014-00134 regarding ratemaking treatment of revenues associated with proposed wholesale market-based-rate purchased power agreements with entities in Nebraska.

Submitted direct and rebuttal testimony on behalf of Big Rivers Electric Corporation in Case No. 2013-00199 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a base rate case.

Submitted direct and rebuttal testimony on behalf of Big Rivers Electric Corporation in Case No. 2012-00535 regarding revenue requirements, pro forma adjustments, cost of service and rate design in a base rate case.

Submitted direct and rebuttal testimony on behalf of Big Rivers Electric Corporation in Case No. 2012-00063 regarding an Environmental Compliance Plan and Environmental Surcharge rate mechanism.

Submitted direct, rebuttal, and rehearing direct testimony on behalf of Big Rivers Electric Corporation in Case No. 2011-00036 regarding revenue requirements and pro forma adjustments in a base rate case.

Submitted direct testimony for Louisville Gas & Electric Company in Case No. 2009-00549 and for Kentucky Utilities Company in Case No. 2009-00548 for adjustment of electric and gas base rates, in support of a new service offering for Low Emission Vehicles, revised special charges, and company offerings aimed at assisting customers.

Submitted discovery responses for Kentucky Utilities and/or Louisville Gas & Electric Company in various customer inquiry matters, including Case Nos. 2009-00421, 2009-00312, and 2009-00364.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2008-00148 regarding the 2008 Joint Integrated Resource Plan.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Administrative Case No. 2007-00477 regarding an investigation of the energy and regulatory issues in Kentucky's 2007 Energy Act.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00319 for the review, modification, and continuation of Energy Efficiency Programs and DSM Cost Recovery Mechanisms.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2007-00067 for approval of a proposed Green Energy program and associated tariff riders.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00467 and 2005-00472 regarding a Certificate of Public Convenience and Necessity for the construction of transmission facilities.

Submitted discovery responses for Kentucky Utilities in Case No. 2005-00405 regarding the transfer of a utility hydroelectric power plant to a private developer.

Submitted discovery responses for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2005-00162 for the 2005 Joint Integrated Resource Plan.

Presented company position for Louisville Gas & Electric Company and Kentucky Utilities Company at public meetings held in Case Nos. 2005-00142 and 2005-00154 regarding routes for proposed transmission lines.

Supported Louisville Gas & Electric Company and Kentucky Utilities Company in a Focused Management Audit of Fuel Procurement practices by Liberty Consulting in 2004.

Supported Louisville Gas & Electric Company and Kentucky Utilities Company in an Investigation into their Membership in the Midwest Independent Transmission System Operator, Inc. ("MISO") in Case No. 2003-00266.

Supported Louisville Gas & Electric Company and Kentucky Utilities Company in a Focused Management Audit of its Earning Sharing Mechanism by Barrington-Wellesley Group in 2002-2003.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00381 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Submitted direct testimony for Louisville Gas & Electric Company and Kentucky Utilities Company in Case No. 2002-00029 regarding a Certificate of Public Convenience and Necessity for the acquisition of two combustion turbines.

#### Missouri

Submitted direct, rebuttal and surrebuttal testimony for Evergy Metro, Inc. in Case No. ER-2022-0130 regarding a jurisdictional cost allocation analysis in a retail rate case.

#### Virginia

Submitted direct testimony for Kentucky Utilities Company d/b/a Old Dominion Power in Case No. PUE-2002-00570 regarding a Certificate of Public Convenience and Necessity for the acquisition of four combustion turbines.

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 365 - Overhead Conductors and Devices

PRIMARY

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y^n^0.5	n^0.5	xn^0.5
1	AA 6201 Aluminum Alloy 1/0	105.53	\$ 6,516.62	4,722	1.38	94.83	68.72	7,251.83
2	AL All Aluminum 1/0	105.53	\$ 552.00	400	1.38	27.60	20.00	2,110.60
3	AA 6201 Aluminum Alloy 2	66.37	\$ 3,912.01	4,396	0.89	59.01	66.30	4,400.25
4	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 199.36	224	0.89	13.32	14.97	993.34
5	AA 6201 Aluminum Alloy 4/0	211.59	\$ 33,229.53	16,954	1.96	255.21	130.21	27,550.48
6	AL All Aluminum 4/0	211.59	\$ 3,379.04	1,724	1.96	81.38	41.52	8,785.45
7	AL All Aluminum 556	556.00	\$ 88,286.45	29,928	2.95	510.34	173.00	96,185.77
8	AA 6201 Aluminum Alloy 1/0	105.53	\$ 2,307.30	1,672	1.38	56.43	40.89	4,315.08
9	AL All Aluminum 1/0	105.53	\$ 122.82	89	1.38	13.02	9.43	995.57
10	AA 6201 Aluminum Alloy 2	66.37	\$ 6,661.53	7,485	0.89	77.00	86.52	5,742.01
11	CU Copper 4	41.74	\$ 774.87	270	2.87	47.16	16.43	685.85
12	AA 6201 Aluminum Alloy 4/0	211.59	\$ 14,877.91	7,591	1.96	170.77	87.13	18,434.78
13	AL All Aluminum 556	556.00	\$ 22,787.78	7,725	2.95	259.28	87.89	48,866.90
14	CON-2-AAA-1-B	66.37	\$ 67,666.41	76,030	0.89	245.40	275.73	18,300.52
15	AA 6201 Aluminum Alloy	66.37	\$ 10,530.09	11,832	0.89	96.81	108.77	7,219.26
16	AL All Aluminum	66.37	\$ 2,990.31	3,360	0.89	51.59	57.96	3,847.11
17	AS Aluminum Conductor, Steel Reinforced (ACSR)	66.37	\$ 1,297.60	1,458	0.89	33.98	38.18	2,534.24
18	CC Copperweld Copper	41.74	\$ 81,026.64	28,232	2.87	482.23	168.02	7,013.35
19	CU Copper	41.74	\$ 3,323.46	1,158	2.87	97.66	34.03	1,420.39
20	AA 6201 Aluminum Alloy 1	83.69	\$ 627.89	455	1.38	29.44	21.33	1,785.15
21	CU Copper 1	83.69	\$ 807.43	283	2.85	47.97	16.83	1,408.65
22	1/0	105.53	\$ 1,139.00	825	1.38	39.65	28.73	3,031.78
23	AA 6201 Aluminum Alloy 1/0	105.53	\$ 1,394,798.28	1,010,723	1.38	1,387.38	1,005.35	106,094.31
24	AL All Aluminum 1/0	105.53	\$ 674,005.43	488,410	1.38	964.43	698.86	73,751.03
25	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 196,583.54	142,452	1.38	520.85	377.43	39,829.97
26	CU Copper 1/0	105.53	\$ 29,862.33	10,478	2.85	291.73	102.36	10,802.28
27	CW Copperweld 1/0	105.53	\$ 9,697.35	3,403	2.85	166.25	58.33	6,155.74
28	AS Aluminum Conductor, Steel Reinforced (ACSR) 159	159.00	\$ 44.16	32	1.38	7.81	5.66	899.44
29	2	66.37	\$ 2,605.07	2,927	0.89	48.15	54.10	3,590.76
30	A5 5005 Aluminum Alloy 2	66.37	\$ 1,811.78	2,036	0.89	40.16	45.12	2,994.54
31	AA 6201 Aluminum Alloy 2	66.37	\$ 27,034,246.85	30,375,558	0.89	4,905.15	5,511.40	365,791.79
32	AL All Aluminum 2	66.37	\$ 651,288.47	731,785	0.89	761.35	855.44	56,775.83
33	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 6,032,984.00	6,778,634	0.89	2,317.19	2,603.58	172,799.67
34	CC Copperweld Copper 2	66.37	\$ 10,556.86	4,327	2.44	160.50	65.78	4,365.60
35	CU Copper 2	66.37	\$ 188,240.68	77,148	2.44	677.72	277.75	18,434.60
36	CW Copperweld 2	66.37	\$ 4,382.24	1,796	2.44	103.41	42.38	2,812.71
37	AA 6201 Aluminum Alloy 2/0	133.07	\$ 701.68	358	1.96	37.08	18.92	2,517.80
38	AL All Aluminum 2/0	133.07	\$ 1,899.10	969	1.96	61.01	31.13	4,142.16
39	AS Aluminum Conductor, Steel Reinforced (ACSR) 2/0	133.07	\$ 2,877.24	1,468	1.96	75.10	38.31	5,098.47
40	AA 6201 Aluminum Alloy 2A	66.37	\$ 112.14	126	0.89	9.99	11.22	745.00
41	CC Copperweld Copper 2A	66.37	\$ 101,781.33	41,714	2.44	498.34	204.24	13,555.36
42	AA 6201 Aluminum Alloy 3/0	167.80	\$ 858.48	438	1.96	41.02	20.93	3,511.79
43	AL All Aluminum 3/0	167.80	\$ 4,742.00	2,419	1.96	96.41	49.19	8,253.63
44	AS Aluminum Conductor, Steel Reinforced (ACSR) 3/0	167.80	\$ 3,575.47	1,824	1.96	83.71	42.71	7,166.89
45	AA 6201 Aluminum Alloy 336	336.00	\$ 228.69	99	2.31	22.98	9.95	3,343.16
46	AL All Aluminum 336	336.00	\$ 1,785.42	773	2.31	64.22	27.80	9,341.22
47	AS Aluminum Conductor, Steel Reinforced (ACSR) 336	336.00	\$ 7,798.74	3,376	2.31	134.22	58.10	19,522.96
48	4	41.74	\$ 543.75	725	0.75	20.19	26.93	1,123.88
49	A5 5005 Aluminum Alloy 4	41.74	\$ 1,042.47	1,390	0.75	27.96	37.28	1,556.16
50	AA 6201 Aluminum Alloy 4	41.74	\$ 24,863.99	33,152	0.75	136.56	182.08	7,599.89
51	AL All Aluminum 4	41.74	\$ 20,404.07	27,205	0.75	123.71	164.94	6,884.62
52	AS Aluminum Conductor, Steel Reinforced (ACSR) 4	41.74	\$ 1,503,481.72	2,004,642	0.75	1,061.89	1,415.85	59,097.74
53	CC Copperweld Copper 4	41.74	\$ 14,219.93	4,955	2.87	202.02	70.39	2,938.06
54	CU Copper 4	41.74	\$ 22,851,426.52	7,962,170	2.87	8,098.37	2,821.73	117,779.08
55	CW Copperweld 4	41.74	\$ 42,930.18	14,958	2.87	351.01	122.30	5,104.97
56	4/0	211.59	\$ 156.80	80	1.96	17.53	8.94	1,892.52
57	AA 6201 Aluminum Alloy 4/0	211.59	\$ 170,558.75	87,020	1.96	578.18	294.99	62,417.17
58	AL All Aluminum 4/0	211.59	\$ 128,078.28	65,346	1.96	501.03	255.63	54,088.49
59	AS Aluminum Conductor, Steel Reinforced (ACSR) 4/0	211.59	\$ 44,783.12	22,849	1.96	296.27	151.16	31,983.37
60	CU Copper 4/0	211.59	\$ 29,475.02	6,179	4.77	374.96	78.61	16,632.71
61	AA 6201 Aluminum Alloy 4A	41.74	\$ 983.99	1,312	0.75	27.17	36.22	1,511.88
62	AS Aluminum Conductor, Steel Reinforced (ACSR) 4A	41.74	\$ 392.99	524	0.75	17.17	22.89	955.45
63	CC Copperweld Copper 4A	41.74	\$ 814,524.05	283,806	2.87	1,528.95	532.73	22,236.35
64	CU Copper 4A	41.74	\$ 2,031.85	708	2.87	76.36	26.61	1,110.60
65	AL All Aluminum 556	556.00	\$ 23,642.69	8,014	2.95	264.09	89.52	49,775.11
66	6	26.25	\$ 3,070.04	1,070	2.87	93.87	32.71	858.54
67	AA 6201 Aluminum Alloy 6	26.25	\$ 11,034.66	14,713	0.75	90.97	121.30	3,184.04
68	AL All Aluminum 6	26.25	\$ 6,239.18	8,319	0.75	68.41	91.21	2,394.21
69	AS Aluminum Conductor, Steel Reinforced (ACSR) 6	26.25	\$ 6,485.04	8,647	0.75	69.74	92.99	2,440.93
70	CC Copperweld Copper 6	26.25	\$ 4,220,638.19	1,470,606	2.87	3,480.41	1,212.69	31,832.99
71	CU Copper 6	26.25	\$ 851,691.13	296,756	2.87	1,563.44	544.75	14,299.78
72	CW Copperweld 6	26.25	\$ 1,475.18	514	2.87	65.07	22.67	595.13
73	CC Copperweld Copper 6A	26.25	\$ 12,803,889.07	4,461,285	2.87	6,061.94	2,112.18	55,444.61
74	CU Copper 6A	26.25	\$ 11,137.78	3,881	2.87	178.79	62.30	1,635.26
75	AA 6201 Aluminum Alloy 8	16.51	\$ 1,033.49	1,378	0.75	27.84	37.12	612.87
76	CC Copperweld Copper 8	16.51	\$ 384,182.16	133,861	2.87	1,050.05	365.87	6,040.53
77	CU Copper 8	16.51	\$ 955.71	333	2.87	52.37	18.25	301.28
78	CC Copperweld Copper 8A	16.51	\$ 652,503.54	227,353	2.87	1,368.46	476.82	7,872.23
79	CON-2-AAA-1-B	66.37	\$ 169.10	190	0.89	12.27	13.78	914.85
80	AA 6201 Aluminum Alloy 1/0	105.53	\$ 39,588.39	12,980	3.05	347.48	113.93	12,022.92
81	AL All Aluminum 1/0	105.53	\$ 42,896.18	14,064	3.05	361.71	118.59	12,515.13
82	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 427.00	140	3.05	36.09	11.83	1,248.65
83	159	159.00	\$ 1,512.80	496	3.05	67.93	22.27	3,541.10
84	AA 6201 Aluminum Alloy 159	159.00	\$ 567.30	186	3.05	41.60	13.64	2,168.47

Kentucky Power Company  
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Account 365 - Overhead Conductors and Devices

PRIMARY

#	Description	Size	Cost	Quantity	Actual	Linear Regression Inputs		
					Unit Cost (\$ per Unit)	y^n^0.5	n^0.5	xn^0.5
85	AL All Aluminum 159	159.00	\$ 16,724.03	5,483	3.05	225.85	74.05	11,773.83
86	AS Aluminum Conductor, Steel Reinforced (ACSR) 159	159.00	\$ 340,632.94	111,683	3.05	1,019.28	334.19	53,136.20
87	AA 6201 Aluminum Alloy 2	66.37	\$ 6,145.89	2,845	2.16	115.22	53.34	3,540.28
88	AL All Aluminum 2	66.37	\$ 7,218.72	3,342	2.16	124.87	57.81	3,836.85
89	CU Copper 2	66.37	\$ 444.96	206	2.16	31.00	14.35	952.59
90	AS Aluminum Conductor, Steel Reinforced (ACSR) 3/0	167.80	\$ 1,942.39	449	4.33	91.71	21.18	3,553.99
91	AL All Aluminum 336	336.00	\$ 4,760.23	1,099	4.33	143.57	33.16	11,140.62
92	AA 6201 Aluminum Alloy 4/0	211.59	\$ 176,413.25	40,742	4.33	874.00	201.85	42,708.74
93	AL All Aluminum 4/0	211.59	\$ 58,859.77	13,593	4.33	504.84	116.59	24,669.51
94	AS Aluminum Conductor, Steel Reinforced (ACSR) 4/0	211.59	\$ 6,698.51	1,547	4.33	170.31	39.33	8,322.24
95	AL All Aluminum 556	556.00	\$ 3,521,401.48	309,438	11.38	6,330.37	556.27	309,286.83
96	CON-2-AAA-1-B	66.37	\$ 38,933.40	43,745	0.89	186.15	209.15	13,881.55
97	AA 6201 Aluminum Alloy	66.37	\$ 3,717.65	4,177	0.89	57.52	64.63	4,289.55
98	AL All Aluminum	66.37	\$ 193.36	217	0.89	13.12	14.74	978.28
99	AS Aluminum Conductor, Steel Reinforced (ACSR)	66.37	\$ 278.57	313	0.89	15.75	17.69	1,174.21
100	AW Alumweld Steel	66.37	\$ 82.43	93	0.89	8.57	9.62	638.74
101	CU Copper	41.74	\$ 3,788.29	1,320	2.87	104.27	36.33	1,516.47
102	AA 6201 Aluminum Alloy 1	83.69	\$ 763.66	553	1.38	32.46	23.52	1,968.73
103	AS Aluminum Conductor, Steel Reinforced (ACSR) 1	83.69	\$ 151.80	110	1.38	14.47	10.49	877.75
104	1/0	105.53	\$ 10,668.44	7,731	1.38	121.34	87.92	9,278.69
105	AA 6201 Aluminum Alloy 1/0	105.53	\$ 13,775,860.89	9,982,508	1.38	4,360.12	3,159.51	333,423.16
106	AL All Aluminum 1/0	105.53	\$ 1,211,373.89	877,807	1.38	1,292.94	936.91	98,872.50
107	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 1,007,252.82	729,893	1.38	1,178.99	854.34	90,158.28
108	CU Copper 1/0	105.53	\$ 172,688.28	60,592	2.85	701.54	246.16	25,976.76
109	CW Copperweld 1/0	105.53	\$ 89,418.09	31,375	2.85	504.82	177.13	18,692.45
110	AL All Aluminum 10	10.38	\$ 293.94	213	1.38	20.14	14.59	151.53
111	AA 6201 Aluminum Alloy 159	159.00	\$ 3,181.23	2,305	1.38	66.26	48.01	7,634.05
112	AL All Aluminum 159	159.00	\$ 7,699.30	5,579	1.38	103.08	74.69	11,876.35
113	AS Aluminum Conductor, Steel Reinforced (ACSR) 159	159.00	\$ 75,717.83	54,868	1.38	323.25	234.24	37,244.03
114	A5 5005 Aluminum Alloy 2	66.37	\$ 1,515.18	1,702	0.89	36.72	41.26	2,738.48
115	AA 6201 Aluminum Alloy 2	66.37	\$ 13,346,219.34	14,995,752	0.89	3,446.47	3,872.43	257,013.50
116	AL All Aluminum 2	66.37	\$ 236,639.47	265,887	0.89	458.92	515.64	34,223.18
117	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 2,453,847.53	2,757,132	0.89	1,477.81	1,660.46	110,204.82
118	CU Copper 2	66.37	\$ 716,776.21	293,761	2.44	1,322.47	542.00	35,972.34
119	CW Copperweld 2	66.37	\$ 64,553.37	26,456	2.44	396.88	162.65	10,795.34
120	AA 6201 Aluminum Alloy 2/0	133.07	\$ 264.60	135	1.96	22.77	11.62	1,546.13
121	AL All Aluminum 2/0	133.07	\$ 1,909.84	974	1.96	61.18	31.22	4,153.85
122	AS Aluminum Conductor, Steel Reinforced (ACSR) 2/0	133.07	\$ 33,210.14	16,944	1.96	255.13	130.17	17,321.58
123	CU Copper 2/0	133.07	\$ 13,001.68	2,726	4.77	249.03	52.21	6,947.38
124	CC Copperweld Copper 2A	66.37	\$ 32,005.68	13,117	2.44	279.45	114.53	7,601.34
125	AA 6201 Aluminum Alloy 3/0	167.80	\$ 46,248.14	23,596	1.96	301.08	153.61	25,775.74
126	AL All Aluminum 3/0	167.80	\$ 24,514.78	12,508	1.96	219.20	111.84	18,766.27
127	AS Aluminum Conductor, Steel Reinforced (ACSR) 3/0	167.80	\$ 620,662.73	316,665	1.96	1,102.95	562.73	94,426.04
128	CU Copper 3/0	167.80	\$ 10,873.02	2,279	4.77	227.74	47.74	8,011.39
129	AS Aluminum Conductor, Steel Reinforced (ACSR) 3/8	49.53	\$ 3,575.63	1,824	1.96	83.72	42.71	2,115.39
130	AW Alumweld Steel 3/8	49.53	\$ 2,918.24	1,489	1.96	75.63	38.59	1,911.06
131	AA 6201 Aluminum Alloy 336	336.00	\$ 98,481.38	42,633	2.31	476.96	206.48	69,376.17
132	AL All Aluminum 336	336.00	\$ 107,560.41	46,563	2.31	498.46	215.78	72,503.59
133	AS Aluminum Conductor, Steel Reinforced (ACSR) 336	336.00	\$ 361,786.86	156,618	2.31	914.18	395.75	132,971.84
134	AL All Aluminum 350	350.00	\$ 4,322.54	1,871	2.31	99.93	43.26	15,140.20
135	AS Aluminum Conductor, Steel Reinforced (ACSR) 397	397.00	\$ 15,533.02	7,925	1.96	174.48	89.02	35,341.94
136	AA 6201 Aluminum Alloy 4	41.74	\$ 18,168.56	24,225	0.75	116.73	155.64	6,496.54
137	AL All Aluminum 4	41.74	\$ 21,163.46	28,218	0.75	125.99	167.98	7,011.57
138	AS Aluminum Conductor, Steel Reinforced (ACSR) 4	41.74	\$ 84,765.26	113,020	0.75	252.14	336.18	14,032.36
139	CC Copperweld Copper 4	41.74	\$ 5,186.06	1,807	2.87	122.00	42.51	1,774.31
140	CU Copper 4	41.74	\$ 7,575,199.06	2,639,442	2.87	4,662.71	1,624.64	67,812.31
141	CW Copperweld 4	41.74	\$ 42,127.98	14,679	2.87	347.72	121.16	5,057.05
142	4/0	211.59	\$ 123.48	63	1.96	15.56	7.94	1,679.44
143	A5 5005 Aluminum Alloy 4/0	211.59	\$ 2,351.94	1,200	1.96	67.90	34.64	7,329.60
144	AA 6201 Aluminum Alloy 4/0	211.59	\$ 23,743,258.88	12,113,908	1.96	6,821.79	3,480.50	736,439.83
145	AL All Aluminum 4/0	211.59	\$ 1,871,591.83	954,894	1.96	1,915.29	977.19	206,762.93
146	AS Aluminum Conductor, Steel Reinforced (ACSR) 4/0	211.59	\$ 1,014,176.91	517,437	1.96	1,409.89	719.33	152,203.26
147	AW Alumweld Steel 4/0	211.59	\$ 460.60	235	1.96	30.05	15.33	3,243.61
148	CU Copper 4/0	211.59	\$ 979,800.50	205,409	4.77	2,161.86	453.22	95,896.95
149	AL All Aluminum 4A	41.74	\$ 143.25	191	0.75	10.37	13.82	576.86
150	CC Copperweld Copper 4A	41.74	\$ 381,312.65	132,862	2.87	1,046.12	364.50	15,214.30
151	AA 6201 Aluminum Alloy 556	556.00	\$ 27,905.47	9,459	2.95	286.92	97.26	54,076.48
152	AL All Aluminum 556	556.00	\$ 22,488,907.66	7,623,359	2.95	8,145.08	2,761.04	1,535,139.92
153	AA 6201 Aluminum Alloy 6	26.25	\$ 2,869.43	3,826	0.75	46.39	61.85	1,623.66
154	AL All Aluminum 6	26.25	\$ 2,448.61	3,265	0.75	42.85	57.14	1,499.89
155	CC Copperweld Copper 6	26.25	\$ 933,475.68	325,253	2.87	1,636.79	570.31	14,970.62
156	CU Copper 6	26.25	\$ 451,220.88	157,220	2.87	1,137.98	396.51	10,408.38
157	CW Copperweld 6	26.25	\$ 596.96	208	2.87	41.39	14.42	378.58
158	CC Copperweld Copper 6A	26.25	\$ 876,905.60	305,542	2.87	1,586.42	552.76	14,509.91
159	CU Copper 6A	26.25	\$ 2,683.62	935	2.87	87.76	30.58	802.69
160	AL All Aluminum 7#8	795.00	\$ 191.02	56	3.44	25.63	7.45	5,924.22
161	AW Alumweld Steel 7#8	795.00	\$ 1,541.12	448	3.44	72.81	21.17	16,826.98
162	AL All Aluminum 750	750.00	\$ 4,299.86	1,250	3.44	121.62	35.35	26,516.08
163	AL All Aluminum 795	795.00	\$ 573.07	167	3.44	44.40	12.91	10,261.05
164	CC Copperweld Copper 8	16.51	\$ 45,473.74	15,845	2.87	361.26	125.87	2,078.20
165	CU Copper 8	16.51	\$ 295.61	103	2.87	29.13	10.15	167.56
166	CC Copperweld Copper 8A	16.51	\$ 176,340.66	61,443	2.87	711.41	247.88	4,092.44
167	AA 6201 Aluminum Alloy 2	199.11	\$ 1,145.06	1,287	0.89	31.92	35.87	7,141.86
168	AL All Aluminum 4/0	634.77	\$ 7,667.40	3,912	1.96	122.59	62.55	39,702.01



Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 365 - Overhead Conductors and Devices

PRIMARY

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y^n^0.5	n^0.5	xn^0.5
169	AL All Aluminum 556	1,668.00	\$ 34,620.67	11,736	2.95	319.58	108.33	180,697.76
170	AA 6201 Aluminum Alloy 1/0	105.53	\$ 492.63	357	1.38	26.07	18.89	1,993.87
171	AL All Aluminum 1/0	105.53	\$ 622.23	451	1.38	29.30	21.23	2,240.84
172	AA 6201 Aluminum Alloy 2	66.37	\$ 79,475.01	89,298	0.89	265.96	298.83	19,833.17
173	AL All Aluminum 2	66.37	\$ 6,709.12	7,538	0.89	77.27	86.82	5,762.48
174	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 218.05	245	0.89	13.93	15.65	1,038.85
175	CU Copper 4	41.74	\$ 2,447.56	853	2.87	83.81	29.20	1,218.93
176	AL All Aluminum 4/0	211.59	\$ 3,069.85	1,566	1.96	77.57	39.58	8,373.86
177	CC Copperweld Copper 6	26.25	\$ 2,109.45	735	2.87	77.81	27.11	711.66
178	CC Copperweld Copper 8A	16.51	\$ 370.23	129	2.87	32.60	11.36	187.52
179	CON-2-AAA-1-B	66.37	\$ 428.97	482	0.89	19.54	21.95	1,457.10
180	AA 6201 Aluminum Alloy	66.37	\$ 491.28	552	0.89	20.91	23.49	1,559.34
181	AA 6201 Aluminum Alloy 1/0	105.53	\$ 53,455.94	38,736	1.38	271.60	196.82	20,769.90
182	AL All Aluminum 1/0	105.53	\$ 2,865.42	2,076	1.38	62.88	45.57	4,808.73
183	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 3,683.74	2,669	1.38	71.30	51.67	5,452.32
184	AS Aluminum Conductor, Steel Reinforced (ACSR) 159	159.00	\$ 525.82	381	1.38	26.94	19.52	3,103.68
185	AA 6201 Aluminum Alloy 2	66.37	\$ 93,237.14	104,761	0.89	288.06	323.67	21,481.83
186	AL All Aluminum 2	66.37	\$ 3,153.17	3,543	0.89	52.97	59.52	3,950.49
187	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 17,159.16	19,280	0.89	123.58	138.85	9,215.63
188	AS Aluminum Conductor, Steel Reinforced (ACSR) 3/0	167.80	\$ 1,975.60	1,008	1.96	62.23	31.75	5,327.38
189	CU Copper 4	41.74	\$ 95,565.78	33,298	2.87	523.71	182.48	7,616.63
190	AA 6201 Aluminum Alloy 4/0	211.59	\$ 305,104.71	155,666	1.96	773.31	394.54	83,481.75
191	AL All Aluminum 4/0	211.59	\$ 10,519.07	5,367	1.96	143.59	73.26	15,500.86
192	AS Aluminum Conductor, Steel Reinforced (ACSR) 4/0	211.59	\$ 2,337.73	1,193	1.96	67.69	34.54	7,307.43
193	CU Copper 4/0	211.59	\$ 601.02	126	4.77	53.54	11.22	2,375.09
194	CC Copperweld Copper 4A	41.74	\$ 8,882.48	3,095	2.87	159.66	55.63	2,322.09
195	AL All Aluminum 556	556.00	\$ 332,918.77	112,854	2.95	991.01	335.94	186,781.10
196	CC Copperweld Copper 6	26.25	\$ 7,923.87	2,761	2.87	150.80	52.54	1,379.29
197	CC Copperweld Copper 6A	26.26	\$ 6,331.11	2,206	2.87	134.80	46.97	1,233.14
198	TOTAL		\$ 182,004,912.79	114,218,402				

Zero Intercept Linear Regression Results

LINEST Array

202	Size Coefficient (\$ per MCM)	0.00339	0.00339	1.1885
203	Zero Intercept (\$ per Unit)	1.18853	0.00047	0.0839
204	R-Square	0.7832	0.78318	666.8112

Plant Classification

208	Total Number of Units	114,218,402
209	Zero Intercept (\$/Unit)	\$ 1.19
210	Minimum System (\$/Unit)	\$ 0.75
211	Use Min System (M) or Zero Intercept (Z)?	Z
212	Zero Intercept or Min System Cost (\$)	\$ 135,752,541
213	Total Cost of Sample	\$ 182,004,913
214	Percentage of Total	0.7459
215	Percentage Classified as Customer-Related	74.59%
216	Percentage Classified as Demand-Related	25.41%

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 365 - Overhead Conductors and Devices

SECONDARY

#	Description	Size	Cost	Quantity	Actual	Linear Regression Inputs		
					Unit Cost (\$ per Unit)	y*n^0.5	n^0.5	xn^0.5
1	AA 6201 Aluminum Alloy 1/0	105.53	\$ 2,873.10	2,081.96	1.38	62.97	45.63	4,815.18
2	AL All Aluminum 1/0	105.53	\$ 1,229.57	890.99	1.38	41.19	29.85	3,150.01
3	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 277.38	201.00	1.38	19.56	14.18	1,496.15
4	AA 6201 Aluminum Alloy 2	66.37	\$ 179,379.45	201,549.94	0.89	399.56	448.94	29,796.36
5	AL All Aluminum 2	66.37	\$ 11,996.18	13,478.85	0.89	103.33	116.10	7,705.45
6	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 5,986.29	6,726.17	0.89	72.99	82.01	5,443.22
7	CU Copper 2	66.37	\$ 580.57	237.94	2.44	37.64	15.43	1,023.78
8	AL All Aluminum 336	336.00	\$ 404.25	175.00	2.31	30.56	13.23	4,444.86
9	AA 6201 Aluminum Alloy 4	41.74	\$ 726.00	968.00	0.75	23.33	31.11	1,298.64
10	AL All Aluminum 4	41.74	\$ 1,059.70	1,412.93	0.75	28.19	37.59	1,568.96
11	AS Aluminum Conductor, Steel Reinforced (ACSR) 4	41.74	\$ 1,027.49	1,369.99	0.75	27.76	37.01	1,544.94
12	CU Copper 4	41.74	\$ 30,624.54	10,670.57	2.87	296.47	103.30	4,311.68
13	CW Copperweld 4	41.74	\$ 272.65	95.00	2.87	27.97	9.75	406.83
14	AA 6201 Aluminum Alloy 4/0	211.59	\$ 3,678.84	1,876.96	1.96	84.91	43.32	9,166.90
15	CC Copperweld Copper 6	26.25	\$ 6,595.23	2,297.99	2.87	137.58	47.94	1,258.36
16	CU Copper 6	26.25	\$ 4,855.98	1,691.98	2.87	118.05	41.13	1,079.76
17	CC Copperweld Copper 6A	26.25	\$ 5,917.94	2,062.00	2.87	130.32	45.41	1,191.99
18	CC Copperweld Copper 8A	16.51	\$ 1,549.74	539.98	2.87	66.69	23.24	383.65
19	CON-2-AAA-2-P	66.37	\$ 357.65	290.77	1.23	20.97	17.05	1,131.74
20	AL All Aluminum	66.37	\$ 571.95	465.00	1.23	26.52	21.56	1,431.19
21	AA 6201 Aluminum Alloy 1	83.69	\$ 703.80	510.00	1.38	31.16	22.58	1,889.99
22	AA 6201 Aluminum Alloy 1/0	105.53	\$ 59,337.14	42,997.93	1.38	286.16	207.36	21,882.64
23	AL All Aluminum 1/0	105.53	\$ 30,248.29	21,919.05	1.38	204.31	148.05	15,623.80
24	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 159,684.53	115,713.43	1.38	469.43	340.17	35,897.80
25	CC Copperweld Copper 1/0	105.53	\$ 456.00	160.00	2.85	36.05	12.65	1,334.86
26	CU Copper 1/0	105.53	\$ 1,433.55	503.00	2.85	63.92	22.43	2,366.79
27	AA 6201 Aluminum Alloy 2	66.37	\$ 207,884.52	233,578.11	0.89	430.14	483.30	32,076.57
28	AL All Aluminum 2	66.37	\$ 28,132.07	31,609.07	0.89	158.23	177.79	11,799.88
29	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 368,989.15	414,594.55	0.89	573.06	643.89	42,734.99
30	CC Copperweld Copper 2	66.37	\$ 2,182.29	894.38	2.44	72.97	29.91	1,984.87
31	CU Copper 2	66.37	\$ 77,045.88	31,576.18	2.44	433.58	177.70	11,793.74
32	CW Copperweld 2	66.37	\$ 736.88	302.00	2.44	42.40	17.38	1,153.39
33	AL All Aluminum 3/0	167.80	\$ 486.08	248.00	1.96	30.87	15.75	2,642.52
34	AS Aluminum Conductor, Steel Reinforced (ACSR) 3/0	167.80	\$ 3,534.39	1,803.26	1.96	83.23	42.46	7,125.59
35	AL All Aluminum 336	336.00	\$ 1,604.99	694.80	2.31	60.89	26.36	8,856.64
36	AS Aluminum Conductor, Steel Reinforced (ACSR) 336	336.00	\$ 591.36	256.00	2.31	36.96	16.00	5,376.00
37	AA 6201 Aluminum Alloy 4	41.74	\$ 4,354.32	5,805.76	0.75	57.15	76.20	3,180.40
38	AL All Aluminum 4	41.74	\$ 44,108.48	58,811.30	0.75	181.88	242.51	10,122.38
39	AS Aluminum Conductor, Steel Reinforced (ACSR) 4	41.74	\$ 48,630.72	64,840.96	0.75	190.98	254.64	10,628.63
40	CU Copper 4	41.74	\$ 2,599,064.14	905,597.26	2.87	2,731.17	951.63	39,720.98
41	CW Copperweld 4	41.74	\$ 18,020.39	6,278.88	2.87	227.42	79.24	3,307.45
42	AA 6201 Aluminum Alloy 4/0	211.59	\$ 2,228.46	1,136.97	1.96	66.09	33.72	7,134.60
43	AL All Aluminum 4/0	211.59	\$ 8,391.03	4,281.14	1.96	128.24	65.43	13,844.42
44	AS Aluminum Conductor, Steel Reinforced (ACSR) 4/0	211.59	\$ 1,916.14	977.62	1.96	61.28	31.27	6,615.77
45	CU Copper 4/0	211.59	\$ 849.06	178.00	4.77	63.64	13.34	2,822.96
46	CC Copperweld Copper 4A	211.59	\$ 9,761.16	3,401.10	2.87	167.38	58.32	12,339.71
47	AL All Aluminum 556	556.00	\$ 1,533.94	519.98	2.95	67.27	22.80	12,678.51
48	AL All Aluminum 6	26.25	\$ 1,657.47	2,209.96	0.75	35.26	47.01	1,234.02
49	AS Aluminum Conductor, Steel Reinforced (ACSR) 6	26.25	\$ 1,181.97	1,575.96	0.75	29.77	39.70	1,042.08
50	CC Copperweld Copper 6	26.25	\$ 274,010.55	95,474.06	2.87	886.80	308.99	8,110.96
51	CU Copper 6	26.25	\$ 188,355.92	65,629.24	2.87	735.24	256.18	6,724.78
52	CW Copperweld 6	26.25	\$ 75,380.49	26,264.98	2.87	465.13	162.06	4,254.20
53	AL All Aluminum 6A	26.25	\$ 2,736.00	3,648.00	0.75	45.30	60.40	1,585.47
54	CC Copperweld Copper 6A	26.25	\$ 242,103.67	84,356.68	2.87	833.57	290.44	7,624.11
55	CC Copperweld Copper 8	16.51	\$ 2,512.63	875.48	2.87	84.92	29.59	488.51
56	CU Copper 8	16.51	\$ 1,635.90	570.00	2.87	68.52	23.87	394.17
57	CC Copperweld Copper 8A	16.51	\$ 3,019.24	1,052.00	2.87	93.09	32.43	535.49
58	AA 6201 Aluminum Alloy 1/0	105.53	\$ 1,110.09	431.94	2.57	53.41	20.78	2,193.25
59	AL All Aluminum 1/0	105.53	\$ 2,420.94	942.00	2.57	78.88	30.69	3,238.93
60	AL All Aluminum 2	66.37	\$ 334.80	216.00	1.55	22.78	14.70	975.44
15	CU Copper 4	41.74	\$ 1,124.51	1,041.21	1.08	34.85	32.27	1,346.86
16	AL All Aluminum 4/0	211.59	\$ 884.10	210.00	4.21	61.01	14.49	3,066.23
17	CON-2-AAA-2-P	66.37	\$ 27,339.51	22,227.24	1.23	183.38	149.09	9,894.97
18	AL All Aluminum	66.37	\$ 10,739.06	8,730.94	1.23	114.93	93.44	6,201.58
19	CU Copper 1	83.69	\$ 558.60	196.00	2.85	39.90	14.00	1,171.66
20	1/0	105.53	\$ 825.24	598.00	1.38	33.75	24.45	2,580.63
21	AA 6201 Aluminum Alloy 1/0	105.53	\$ 72,096.13	52,243.57	1.38	315.42	228.57	24,120.84
22	AL All Aluminum 1/0	105.53	\$ 361,245.03	261,771.76	1.38	706.06	511.64	53,992.98
23	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 212,961.93	154,320.24	1.38	542.11	392.84	41,456.00
24	CU Copper 1/0	105.53	\$ 43,611.70	15,302.35	2.85	352.55	123.70	13,054.34
25	A5 5005 Aluminum Alloy 2	66.37	\$ 507.30	570.00	0.89	21.25	23.87	1,584.56
26	AA 6201 Aluminum Alloy 2	66.37	\$ 310,657.60	349,053.48	0.89	525.82	590.81	39,211.89
27	AL All Aluminum 2	66.37	\$ 132,119.65	148,449.05	0.89	342.91	385.29	25,571.75
28	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 539,612.51	606,306.19	0.89	693.00	778.66	51,679.44
29	CC Copperweld Copper 2	66.37	\$ 1,507.92	618.00	2.44	60.66	24.86	1,649.93
30	CU Copper 2	66.37	\$ 161,334.41	66,120.66	2.44	627.42	257.14	17,066.34
31	CW Copperweld 2	66.37	\$ 3,572.16	1,464.00	2.44	93.36	38.26	2,539.47
32	AA 6201 Aluminum Alloy 2/0	133.07	\$ 2,342.16	1,194.98	1.96	67.75	34.57	4,600.03
33	AL All Aluminum 2/0	133.07	\$ 5,584.04	2,849.00	1.96	104.62	53.38	7,102.75
34	AS Aluminum Conductor, Steel Reinforced (ACSR) 2/0	133.07	\$ 5,754.48	2,935.96	1.96	106.20	54.18	7,210.33

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 365 - Overhead Conductors and Devices

SECONDARY

#	Description	Size	Cost	Quantity	Actual	Linear Regression Inputs		
					Unit Cost (\$ per Unit)	y*n^0.5	n^0.5	xn^0.5
35	AA 6201 Aluminum Alloy 3/0	167.80	\$ 570.36	291.00	1.96	33.44	17.06	2,862.45
36	AL All Aluminum 3/0	167.80	\$ 51,539.89	26,295.86	1.96	317.83	162.16	27,210.45
37	AS Aluminum Conductor, Steel Reinforced (ACSR) 3/0	167.80	\$ 12,612.84	6,435.12	1.96	157.23	80.22	13,460.78
38	AL All Aluminum 300	300.00	\$ 842.85	364.87	2.31	44.12	19.10	5,730.47
39	AL All Aluminum 336	336.00	\$ 10,097.17	4,371.07	2.31	152.72	66.11	22,214.33
40	AS Aluminum Conductor, Steel Reinforced (ACSR) 336	336.00	\$ 1,113.42	482.00	2.31	50.71	21.95	7,376.71
41	CU Copper 336	336.00	\$ 1,115.73	483.00	2.31	50.77	21.98	7,384.36
42	AL All Aluminum 350	350.00	\$ 2,730.42	1,182.00	2.31	79.42	34.38	12,033.08
43	AA 6201 Aluminum Alloy 4	41.74	\$ 12,872.72	17,163.63	0.75	98.26	131.01	5,468.36
44	AL All Aluminum 4	41.74	\$ 68,484.73	91,312.97	0.75	226.64	302.18	12,613.01
45	AS Aluminum Conductor, Steel Reinforced (ACSR) 4	41.74	\$ 42,889.13	57,185.50	0.75	179.35	239.13	9,981.49
46	CU Copper 4	41.74	\$ 2,955,906.25	1,029,932.49	2.87	2,912.64	1,014.86	42,360.09
47	CW Copperweld 4	41.74	\$ 8,357.35	2,911.97	2.87	154.87	53.96	2,252.40
48	AA 6201 Aluminum Alloy 4/0	211.59	\$ 8,828.23	4,504.20	1.96	131.54	67.11	14,200.51
49	AL All Aluminum 4/0	211.59	\$ 47,663.69	24,318.21	1.96	305.65	155.94	32,995.97
50	AS Aluminum Conductor, Steel Reinforced (ACSR) 4/0	211.59	\$ 3,504.48	1,788.00	1.96	82.88	42.28	8,947.03
51	CU Copper 4/0	211.59	\$ 36,730.81	7,700.38	4.77	418.58	87.75	18,567.41
52	CC Copperweld Copper 4A	41.74	\$ 9,901.41	3,449.97	2.87	168.57	58.74	2,451.66
53	AL All Aluminum 500	500.00	\$ 7,332.37	2,485.55	2.95	147.07	49.86	24,927.65
54	CC Copperweld Copper 6	26.25	\$ 264,206.20	92,057.91	2.87	870.79	303.41	7,964.52
55	CU Copper 6	26.25	\$ 544,512.10	189,725.47	2.87	1,250.10	435.57	11,433.84
56	CW Copperweld 6	26.25	\$ 52,988.70	18,462.96	2.87	389.97	135.88	3,566.81
57	CC Copperweld Copper 6A	26.25	\$ 233,833.57	81,475.11	2.87	819.21	285.44	7,492.76
58	AL All Aluminum 750	750.00	\$ 1,951.51	567.30	3.44	81.93	23.82	17,863.55
59	CC Copperweld Copper 8	16.51	\$ 3,462.68	1,206.51	2.87	99.69	34.73	573.47
60	CU Copper 8	16.51	\$ 499.38	174.00	2.87	37.86	13.19	217.78
61	CC Copperweld Copper 8A	16.51	\$ 3,980.60	1,386.97	2.87	106.88	37.24	614.87
62	AL All Aluminum	105.53	\$ 622.08	216.00	2.88	42.33	14.70	1,550.97
63	AL All Aluminum 1/0	105.53	\$ 12,715.43	4,415.08	2.88	191.36	66.45	7,012.05
64	AS Aluminum Conductor, Steel Reinforced (ACSR) 1/0	105.53	\$ 5,434.56	1,887.00	2.88	125.11	43.44	4,584.18
65	AA 6201 Aluminum Alloy 2	66.37	\$ 5,366.65	2,965.00	1.81	98.56	54.45	3,613.97
66	AL All Aluminum 2	66.37	\$ 5,907.77	3,263.96	1.81	103.41	57.13	3,791.79
67	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 6,420.00	3,546.96	1.81	107.80	59.56	3,952.76
68	CU Copper 2	66.37	\$ 629.88	348.00	1.81	33.77	18.65	1,238.12
69	AA 6201 Aluminum Alloy 2/0	133.07	\$ 1,105.56	332.00	3.33	60.68	18.22	2,424.65
70	AL All Aluminum 2/0	133.07	\$ 7,559.10	2,270.00	3.33	158.66	47.64	6,340.06
71	CU Copper 2/0	133.07	\$ 785.88	236.00	3.33	51.16	15.36	2,044.26
72	AL All Aluminum 3/0	167.80	\$ 5,495.04	1,152.00	4.77	161.90	33.94	5,695.32
73	AA 6201 Aluminum Alloy 336	336.00	\$ 1,047.36	96.00	10.91	106.90	9.80	3,292.11
74	AL All Aluminum 336	336.00	\$ 34,476.47	3,160.08	10.91	613.30	56.21	18,888.10
75	CU Copper 4	41.74	\$ 2,021.76	1,872.00	1.08	46.73	43.27	1,805.95
76	AL All Aluminum 4/0	211.59	\$ 12,363.84	2,592.00	4.77	242.85	50.91	10,772.40
77	CU Copper 500	500.00	\$ 638.32	79.00	8.08	71.82	8.89	4,444.10
78	CC Copperweld Copper 6	26.25	\$ 3,127.68	1,728.00	1.81	75.24	41.57	1,091.19
79	CU Copper 6	26.25	\$ 745.72	412.00	1.81	36.74	20.30	532.82
80	AL All Aluminum 750	750.00	\$ 8,395.12	1,039.00	8.08	260.45	32.23	24,175.14
81	AL All Aluminum 1/0	105.53	\$ 674.82	489.00	1.38	30.52	22.11	2,333.62
82	AA 6201 Aluminum Alloy 2	66.37	\$ 812.54	912.97	0.89	26.89	30.22	2,005.40
83	AL All Aluminum 2	66.37	\$ 1,224.64	1,376.00	0.89	33.01	37.09	2,461.96
84	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 736.02	826.99	0.89	25.59	28.76	1,908.63
85	AL All Aluminum 336	336.00	\$ 2,772.00	1,200.00	2.31	80.02	34.64	11,639.38
86	CU Copper 4	41.74	\$ 4,741.24	1,652.00	2.87	116.65	40.64	1,696.51
87	AL All Aluminum 4/0	211.59	\$ 250.88	128.00	1.96	22.17	11.31	2,393.87
88	AL All Aluminum 1/0	422.12	\$ 1,264.44	492.00	2.57	57.01	22.18	9,363.07
89	AL All Aluminum 4	83.48	\$ 3,095.26	2,865.98	1.08	57.82	53.53	4,469.09
90	CON-10-AAI-4-P	422.12	\$ 374.40	130.00	2.88	32.84	11.40	4,812.91
91	AL All Aluminum	422.12	\$ 541.44	188.00	2.88	39.49	13.71	5,787.82
92	AL All Aluminum 1/0	422.12	\$ 35,483.56	12,320.68	2.88	319.68	111.00	46,854.71
93	AL All Aluminum 2	265.48	\$ 14,183.16	7,836.00	1.81	160.22	88.52	23,500.60
94	AL All Aluminum 2/0	532.28	\$ 64,408.73	19,341.96	3.33	463.12	139.08	74,027.04
95	AL All Aluminum 336	1,344.00	\$ 507,124.51	46,482.54	10.91	2,352.18	215.60	289,763.84
96	AL All Aluminum 350	1,400.00	\$ 776.61	112.88	6.88	73.10	10.62	14,874.30
97	AL All Aluminum 4	166.96	\$ 2,474.64	1,964.00	1.26	55.84	44.32	7,399.17
98	AL All Aluminum 4/0	846.36	\$ 604,506.92	126,731.01	4.77	1,698.09	355.99	301,298.23
99	CU Copper 6	105.00	\$ 3,149.40	1,740.00	1.81	75.50	41.71	4,379.90
100	AL All Aluminum 750	3,000.00	\$ 12,313.92	1,524.00	8.08	315.43	39.04	117,115.33
101	CON-10-AAA-3-P	251.07	\$ 3,274.67	1,274.19	2.57	91.74	35.70	8,962.14
102	AL All Aluminum	251.07	\$ 755.66	294.03	2.57	44.07	17.15	4,305.17
103	AL All Aluminum 1	251.07	\$ 1,033.14	402.00	2.57	51.53	20.05	5,033.94
104	AA 6201 Aluminum Alloy 1/0	316.59	\$ 930.34	362.00	2.57	48.90	19.03	6,023.54
105	AL All Aluminum 1/0	316.59	\$ 10,287,564.36	4,002,943.33	2.57	5,141.89	2,000.74	633,412.91
106	AL All Aluminum 2	199.11	\$ 79,602.44	51,356.41	1.55	351.26	226.62	45,122.21
107	AL All Aluminum 2/0	399.21	\$ 5,541.15	2,703.00	2.05	106.58	51.99	20,755.08
108	AL All Aluminum 3/0	503.40	\$ 6,698.03	1,590.98	4.21	167.92	39.89	20,079.16
109	AL All Aluminum 336	1,008.00	\$ 131,324.51	31,193.47	4.21	743.56	176.62	178,029.67
110	AL All Aluminum 350	1,050.00	\$ 4,850.40	705.00	6.88	182.68	26.55	27,879.43
111	AL All Aluminum 4	125.22	\$ 25,709.97	20,404.74	1.26	179.98	142.85	17,887.07
112	CU Copper 4	125.22	\$ 2,554.01	2,026.99	1.26	56.73	45.02	5,637.67
113	4/0	634.77	\$ 3,927.93	933.00	4.21	128.59	30.55	19,389.08
114	AL All Aluminum 4/0	634.77	\$ 5,348,057.68	1,270,322.49	4.21	4,745.03	1,127.09	715,440.28

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 365 - Overhead Conductors and Devices

SECONDARY

#	Description	Size	Cost	Quantity	Actual	Linear Regression Inputs		
					Unit Cost (\$ per Unit)	y*n^0.5	n^0.5	xn^0.5
115	CU Copper 4/0	634.77	\$ 766.22	182.00	4.21	56.80	13.49	8,563.52
116	AL All Aluminum 500	1,500.00	\$ 332,163.70	1,199.97	276.81	9,588.86	34.64	51,960.87
117	CC Copperweld Copper 6	78.75	\$ 280.98	223.00	1.26	18.82	14.93	1,175.99
118	CU Copper 6	78.75	\$ 1,539.68	1,221.97	1.26	44.05	34.96	2,752.84
119	CON-2-AAA-2-P	132.74	\$ 2,219.46	1,804.44	1.23	52.25	42.48	5,638.62
120	AL All Aluminum	211.06	\$ 870.84	708.00	1.23	32.73	26.61	5,615.94
121	AL All Aluminum 1/0	211.06	\$ 2,018.74	785.50	2.57	72.03	28.03	5,915.33
122	2	132.74	\$ 435.42	354.00	1.23	23.14	18.81	2,497.49
123	AA 6201 Aluminum Alloy 2	132.74	\$ 390.80	317.72	1.23	21.92	17.82	2,366.05
124	AL All Aluminum 2	132.74	\$ 44,750.14	36,382.23	1.23	234.61	190.74	25,319.00
125	AL All Aluminum 2/0	266.14	\$ 82.00	40.00	2.05	12.97	6.32	1,683.22
126	AL All Aluminum 336	672.00	\$ 1,145.12	272.00	4.21	69.43	16.49	11,082.91
127	4	83.48	\$ 1,182.28	1,094.70	1.08	35.73	33.09	2,762.04
128	AA 6201 Aluminum Alloy 4	83.48	\$ 213.84	198.00	1.08	15.20	14.07	1,174.67
129	AL All Aluminum 4	83.48	\$ 4,345,618.78	4,023,721.09	1.08	2,166.40	2,005.92	167,454.33
130	CU Copper 4	83.48	\$ 6,072.75	5,622.92	1.08	80.99	74.99	6,259.84
131	AL All Aluminum 4/0	423.18	\$ 45,865.26	10,894.36	4.21	439.42	104.38	44,169.86
132	AL All Aluminum 6	52.50	\$ 2,362.87	2,036.96	1.16	52.35	45.13	2,369.47
133	CC Copperweld Copper 6	52.50	\$ 1,339.78	1,154.98	1.16	39.42	33.98	1,784.21
134	CU Copper 6	52.50	\$ 1,205.21	1,038.97	1.16	37.39	32.23	1,692.24
135	CW Copperweld 6	52.50	\$ 348.00	300.00	1.16	20.09	17.32	909.33
136	AL All Aluminum	422.12	\$ 403.20	140.00	2.88	34.08	11.83	4,994.59
137	AL All Aluminum 1/0	422.12	\$ 52,743.28	18,313.64	2.88	389.74	135.33	57,124.61
138	AL All Aluminum 2	265.48	\$ 172,750.45	95,442.24	1.81	559.18	308.94	82,016.67
139	AL All Aluminum 2/0	532.28	\$ 349,388.63	104,921.51	3.33	1,078.64	323.92	172,413.96
140	AL All Aluminum 3/0	671.20	\$ 1,392.84	292.00	4.77	81.51	17.09	11,469.47
141	AL All Aluminum 336	1,344.00	\$ 514,427.45	47,151.92	10.91	2,369.05	217.14	291,842.78
142	AL All Aluminum 350	1,400.00	\$ 2,401.67	349.08	6.88	128.54	18.68	26,157.16
143	AL All Aluminum 4	166.96	\$ 3,900.96	3,096.00	1.26	70.11	55.64	9,289.94
144	AA 6201 Aluminum Alloy 4/0	846.36	\$ 4,083.12	856.00	4.77	139.56	29.26	24,762.36
145	AL All Aluminum 4/0	846.36	\$ 1,005,688.24	210,836.11	4.77	2,190.24	459.17	388,622.22
146	AL All Aluminum 556	2,224.00	\$ 87,553.91	10,835.88	8.08	841.09	104.10	231,508.47
147	AL All Aluminum 750	3,000.00	\$ 1,139.28	141.00	8.08	95.94	11.87	35,623.03
148	CON-10-AAA-3-P	251.07	\$ 24,993.51	9,725.10	2.57	253.44	98.62	24,759.50
149	AL All Aluminum	251.07	\$ 2,636.82	1,026.00	2.57	82.32	32.03	8,042.08
150	AL All Aluminum 1	251.07	\$ 4,572.03	1,779.00	2.57	108.40	42.18	10,589.68
151	1/0	316.59	\$ 663.06	258.00	2.57	41.28	16.06	5,085.19
152	AA 6201 Aluminum Alloy 1/0	316.59	\$ 2,663.06	1,036.21	2.57	82.73	32.19	10,191.10
153	AL All Aluminum 1/0	316.59	\$ 21,877,015.67	8,512,457.46	2.57	7,498.26	2,917.61	923,686.66
154	CU Copper 1/0	316.59	\$ 1,040.85	405.00	2.57	51.72	20.12	6,371.25
155	2	199.11	\$ 860.25	555.00	1.55	36.52	23.56	4,690.72
156	AA 6201 Aluminum Alloy 2	199.11	\$ 649.81	419.23	1.55	31.74	20.48	4,076.80
157	AL All Aluminum 2	199.11	\$ 14,631,752.99	9,439,840.64	1.55	4,762.27	3,072.43	611,752.01
158	CU Copper 2	199.11	\$ 7,775.40	5,016.39	1.55	109.78	70.83	14,102.26
159	AL All Aluminum 2/0	399.21	\$ 90,827.94	44,306.31	2.05	431.51	210.49	84,029.97
160	AL All Aluminum 2A	199.11	\$ 478.95	309.00	1.55	27.25	17.58	3,500.03
161	AL All Aluminum 3/0	503.40	\$ 39,544.53	9,393.00	4.21	408.02	96.92	48,788.26
162	AL All Aluminum 336	1,008.00	\$ 8,321.78	1,976.67	4.21	187.18	44.46	44,815.44
163	AL All Aluminum 350	1,050.00	\$ 5,407.68	786.00	6.88	192.89	28.04	29,437.48
164	AL All Aluminum 4	125.22	\$ 1,150,332.06	912,961.95	1.26	1,203.92	955.49	119,646.51
165	CU Copper 4	125.22	\$ 15,759.75	12,507.74	1.26	140.92	111.84	14,004.36
166	AL All Aluminum 4/0	634.77	\$ 3,628,507.01	861,878.15	4.21	3,908.45	928.37	589,303.92
167	CU Copper 4/0	634.77	\$ 1,831.35	435.00	4.21	87.81	20.86	13,239.18
168	AL All Aluminum 556	1,668.00	\$ 102,973.32	372.00	276.81	5,338.92	19.29	32,171.22
169	AL All Aluminum 6	78.75	\$ 4,237.38	3,363.00	1.26	73.07	57.99	4,566.82
170	CC Copperweld Copper 6	78.75	\$ 1,082.64	859.24	1.26	36.93	29.31	2,308.38
171	AL All Aluminum 750	2,250.00	\$ 3,150.96	389.97	8.08	159.56	19.75	44,432.23
172	CON-10-AAA-3-P	83.69	\$ 357,441.28	139,082.21	2.57	958.45	372.94	31,211.12
173	AL All Aluminum 1/0	105.53	\$ 1,642.23	639.00	2.57	64.97	25.28	2,667.63
174	CU Copper 1/0	105.53	\$ 4,702.39	1,649.96	2.85	115.77	40.62	4,286.60
175	AL All Aluminum 2	66.37	\$ 1,323.70	854.00	1.55	45.30	29.22	1,939.55
176	AS Aluminum Conductor, Steel Reinforced (ACSR) 2	66.37	\$ 237.15	153.00	1.55	19.17	12.37	820.95
177	CU Copper 2	66.37	\$ 326.96	134.00	2.44	28.25	11.58	768.29
178	AL All Aluminum 4	41.74	\$ 1,675.98	1,330.14	1.26	45.95	36.47	1,522.30
179	CU Copper 4	41.74	\$ 1,205.15	956.47	1.26	38.97	30.93	1,290.89
180	AL All Aluminum 4/0	211.59	\$ 1,044.08	248.00	4.21	66.30	15.75	3,332.12
181	CC Copperweld Copper 6	26.25	\$ 250.97	199.18	1.26	17.78	14.11	370.47
182	1/0	316.59	\$ 647.64	252.00	2.57	40.80	15.87	5,025.71
183	AL All Aluminum 4/0	634.77	\$ 3,990.20	948	4.21	129.61	30.79	19,542.16
184	TOTAL		\$ 77,267,142.56	36,042,300				

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 365 - Overhead Conductors and Devices

SECONDARY

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						$y \cdot n^{0.5}$	$n^{0.5}$	$xn^{0.5}$
185								
186	<u>Zero Intercept Linear Regression Results</u>					<u>LINEST Array</u>		
187								
188	Size Coefficient (\$ per MCM)		0.00527			0.00527	0.8775	
189	Zero Intercept (\$ per Unit)		0.87746			0.00072	0.2124	
190	R-Square		0.6090			0.60905	743.2772	
191								
192	<u>Plant Classification</u>							
193								
194	Total Number of Units		36,042,300					
195	Zero Intercept (\$/Unit)	\$	0.88					
196	Minimum System (\$/Unit)	\$	0.75					
197	Use Min System (M) or Zero Intercept (Z)?		Z					
198	Zero Intercept or Min System Cost (\$)	\$	31,625,594					
199	Total Cost of Sample	\$	77,267,143					
200	Percentage of Total		0.4093					
201	Percentage Classified as Customer-Related		40.93%					
202	Percentage Classified as Demand-Related		59.07%					

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 367 - Underground Conductors and Devices PRIMARY

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y*n^0.5	n^0.5	xn^0.5
1	2	66.37	\$ 13,447.90	3,288	4.09	234.52	57.34	3,805.72
2	350	350.00	\$ 35,746.29	4,824	7.41	514.66	69.46	24,309.41
3	4	41.74	\$ 126,393.74	30,903	4.09	718.99	175.79	7,337.59
4	4/0	211.59	\$ 355.68	48	7.41	51.34	6.93	1,465.94
5	6	26.25	\$ 882,621.34	215,800	4.09	1,899.98	464.54	12,194.24
6	6A	26.25	\$ 4,957.08	1,212	4.09	142.39	34.81	913.86
7	8	16.51	\$ 597.14	146	4.09	49.42	12.08	199.49
8	8	16.51	\$ 5,377.32	641	8.39	212.40	25.32	417.97
9	1/0	105.53	\$ 49,728.96	5,013	9.92	702.36	70.80	7,471.79
10	2	66.37	\$ 3,322.44	396	8.39	166.96	19.90	1,320.75
11	350	350.00	\$ 125,788.76	9,175	13.71	1,313.23	95.79	33,525.11
12	350	350.00	\$ 97,999.08	7,148	13.71	1,159.12	84.55	29,591.05
13	4	41.74	\$ 6,649.69	793	8.39	236.20	28.15	1,175.09
14	4/0	211.59	\$ 19,948.05	1,455	13.71	522.96	38.14	8,070.99
15	500	500.00	\$ 8,720.40	344	25.35	470.17	18.55	9,273.62
16	500	500.00	\$ 371,073.30	14,638	25.35	3,067.04	120.99	60,493.80
17	350	350.00	\$ 2,577.48	188	13.71	187.98	13.71	4,798.96
18	500	500.00	\$ 46,441.20	1,832	25.35	1,085.03	42.80	21,400.93
19	750	750.00	\$ 23,616.00	800	29.52	834.95	28.28	21,213.20
20	TOTAL		\$ 1,825,361.84	\$ 298,643.47				

**Zero Intercept Linear Regression Results**

**LINEST Array**

Size Coefficient (\$ per MCM)	0.03793	0.03793	2.9883
Zero Intercept (\$ per Unit)	2.98833	0.00287	0.4583
R-Square	0.9608	0.96081	214.5677

**Plant Classification**

Total Number of Units	298,643
Zero Intercept (\$/Unit)	\$ 2.99
Minimum System (\$/Unit)	\$ 4.09
Use Min System (M) or Zero Intercept (Z)?	Z
Zero Intercept or Min System Cost (\$)	\$ 892,445
Total Cost of Sample	\$ 1,825,362
Percentage of Total	0.4889
Percentage Classified as Customer-Related	48.89%
Percentage Classified as Demand-Related	51.11%

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 367 - Underground Conductors and Devices SECONDARY

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y*n^0.5	n^0.5	xn^0.5
1	350	350.00	\$ 733.14	142	5.17	61.57	11.91	4,167.90
2	1/0	105.53	\$ 145.58	58	2.51	19.12	7.62	803.69
3	12	6.53	\$ 5,379.79	3,005	1.79	98.13	54.82	357.99
4	350	350.00	\$ 5,449.18	1,054	5.17	167.85	32.47	11,362.88
5	4	41.74	\$ 1,033.60	680	1.52	39.64	26.08	1,088.45
6	6	26.25	\$ 2,740.93	2,015	1.36	61.05	44.89	1,178.44
7	6	26.25	\$ 886.00	200	4.43	62.65	14.14	371.23
8	6	26.25	\$ 56,550.59	12,765	4.43	500.52	112.98	2,965.83
9	6	26.25	\$ 160.48	118	1.36	14.77	10.86	285.15
10	350	350.00	\$ 7,899.83	1,528	5.17	202.09	39.09	13,681.44
11	4	41.74	\$ 565.44	372	1.52	29.32	19.29	805.05
12	4/0	211.59	\$ 7,533.44	2,146	3.51	162.61	46.33	9,802.53
13	500	500.00	\$ 2,329.60	280	8.32	139.22	16.73	8,366.60
14	4/0	211.59	\$ 2,042.89	582	3.51	84.68	24.13	5,104.63
15	4/0	211.59	\$ 15,651.27	4,459	3.51	234.38	66.78	14,129.16
16	350	350.00	\$ 114,342.34	16,150	7.08	899.75	127.08	44,478.99
17	4/0	211.59	\$ 4,323.07	938	4.61	141.17	30.62	6,479.49
18	500	500.00	\$ 2,158.94	154	14.03	174.04	12.40	6,202.42
19	1/0	105.53	\$ 173,229.28	69,016	2.51	659.40	262.71	27,723.61
20	2/0	133.07	\$ 15,500.16	4,416	3.51	233.25	66.45	8,842.90
21	350	350.00	\$ 1,585,451.33	306,664	5.17	2,863.00	553.77	193,820.29
22	350	350.00	\$ 5,964.22	1,154	5.17	175.60	33.96	11,887.74
23	4	41.74	\$ 7,698.75	5,065	1.52	108.18	71.17	2,970.58
24	4	41.74	\$ 2,408.70	465	5.18	111.70	21.56	900.08
25	4/0	211.59	\$ 341,069.79	97,171	3.51	1,094.15	311.72	65,957.35
26	4/0	211.59	\$ 2,825.69	805	3.51	99.59	28.37	6,003.49
27	4/0	211.59	\$ 437.07	125	3.51	39.17	11.16	2,361.10
28	500	500.00	\$ 104,500.70	12,560	8.32	932.44	112.07	56,036.10
29	6	26.25	\$ 2,246.68	1,652	1.36	55.28	40.64	1,066.92
30	6	26.25	\$ 9,409.28	2,124	4.43	204.16	46.09	1,209.78
31	8	16.51	\$ 8,602.74	4,806	1.79	124.09	69.33	1,144.56
32	4/0	211.59	\$ 257.00	73	3.51	30.03	8.56	1,810.55
33	4/0	211.59	\$ 10,234.46	2,916	3.51	189.53	54.00	11,425.47
34	TOTAL		\$ 2,499,761.95	555,658				

Zero Intercept Linear Regression Results

LINEST Array

Size Coefficient (\$ per MCM)	0.01043	0.01043	1.6326
Zero Intercept (\$ per Unit)	1.63256	0.00098	0.2923
R-Square	0.9826	0.98264	82.7550

Plant Classification

Total Number of Units	555,658
Zero Intercept (\$/Unit)	\$ 1.63
Minimum System (\$/Unit)	\$ 1.36
Use Min System (M) or Zero Intercept (Z)?	Z
Zero Intercept or Min System Cost (\$)	\$ 907,147
Total Cost of Sample	\$ 2,499,762
Percentage of Total	0.3629
Percentage Classified as Customer-Related	36.29%
Percentage Classified as Demand-Related	63.71%

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 368 - Transformers

#	Description	Size	Cost	Quantity	Actual	Linear Regression Inputs			NARUC CAM	
					Unit Cost (\$ per Unit)	y*n^0.5	n^0.5	xn^0.5	Incl?	Qty
1	UXFR-300-23-208-DR-N	300.0	\$ 18,575.45	1	18,575.45	18,575.45	1.00	300.00	0	-
2	UXFR-500-12-208-DL-N	500.0	\$ 21,740.61	1	21,740.61	21,740.61	1.00	500.00	0	-
3	UXFR-500-12-208-DL-N	500.0	\$ 65,221.83	3	21,740.61	37,655.84	1.73	866.03	0	-
4	UXFR-100-19-120-DL-H	100.0	\$ 190,521.20	20	9,526.06	42,601.84	4.47	447.21	0	-
5	UXFR-100-72-120-DL-L	100.0	\$ 1,157,036.25	155	7,464.75	92,935.39	12.45	1,244.99	0	-
6	UXFR-1000-12-208-DL-N	1,000.0	\$ 166,294.59	7	23,756.37	62,853.45	2.65	2,645.75	0	-
7	UXFR-1000-12-480-DL-T	1,000.0	\$ 553,876.32	17	32,580.96	134,334.74	4.12	4,123.11	0	-
8	UXFR-1000-35-480-DL-T	1,000.0	\$ 103,355.53	1	103,355.53	103,355.53	1.00	1,000.00	0	-
9	UXFR-1000-35-480-DL-T	1,000.0	\$ 1,136,910.83	11	103,355.53	342,791.51	3.32	3,316.62	0	-
10	UXFR-112-12-208-DR-N	112.5	\$ 84,694.61	13	6,514.97	23,490.06	3.61	405.62	0	-
11	UXFR-112-12-480-DL-N	112.5	\$ 28,708.36	4	7,177.09	14,354.18	2.00	225.00	0	-
12	UXFR-112-35-208-DL-N	112.5	\$ 218,861.28	12	18,238.44	63,179.81	3.46	389.71	0	-
13	UXFR-112-35-480-DL-N	112.5	\$ 90,729.55	5	18,145.91	40,575.49	2.24	251.56	0	-
14	UXFR-150-12-208-DL-N	150.0	\$ 520,093.60	40	13,002.34	82,234.02	6.32	948.68	0	-
15	UXFR-150-12-480-DL-N	150.0	\$ 117,998.46	9	13,110.94	39,332.82	3.00	450.00	0	-
16	UXFR-112-35-208-DL-N	150.0	\$ 218,861.28	12	18,238.44	63,179.81	3.46	519.62	0	-
17	UXFR-150-35-480-DL-N	150.0	\$ 54,749.00	5	10,949.80	24,484.50	2.24	335.41	0	-
18	UXFR-1500-12-480-DL-T	1,500.0	\$ 735,848.16	16	45,990.51	183,962.04	4.00	6,000.00	0	-
19	UXFR-1500-35-480-DL-T	1,500.0	\$ 59,561.20	2	29,780.60	42,116.13	1.41	2,121.32	0	-
20	UXFR-1500-35-480-DL-T	1,500.0	\$ 148,903.00	5	29,780.60	66,591.45	2.24	3,354.10	0	-
21	UXFR-167-19-120-DL-H	167.0	\$ 241,124.16	24	10,046.84	49,219.26	4.90	818.13	0	-
22	UXFR-167-72-120-DL-L-N	167.0	\$ 651,010.62	78	8,346.29	73,712.44	8.83	1,474.90	0	-
23	UXFR-2000-35-480-DL-T	2,000.0	\$ 38,645.73	1	38,645.73	38,645.73	1.00	2,000.00	0	-
24	UXFR-225-12-208-DL-N	225.0	\$ 164,853.10	10	16,485.31	52,131.13	3.16	711.51	0	-
25	UXFR-225-12-480-DL-N	225.0	\$ 39,880.53	3	13,293.51	23,025.03	1.73	389.71	0	-
26	UXFR-225-35-208-DL-N	225.0	\$ 163,772.56	7	23,396.08	61,900.21	2.65	595.29	0	-
27	UXFR-225-35-480-DL-N	225.0	\$ 25,387.52	2	12,693.76	17,951.69	1.41	318.20	0	-
28	UXFR-25-19-120-DL-H-N	25.0	\$ 249,196.20	44	5,663.55	37,567.74	6.63	165.83	1	44
29	UXFR-25-72-120-DL-H-N	25.0	\$ 943,634.79	177	5,331.27	70,927.93	13.30	332.60	1	177
30	UXFR-250-72-120-DL-H	250.0	\$ 4,379.61	1	4,379.61	4,379.61	1.00	250.00	0	-
31	UXFR-2500-12-480-DL-T	2,500.0	\$ 127,413.26	1	127,413.26	127,413.26	1.00	2,500.00	0	-
32	UXFR-2500-35-12470-DL	2,500.0	\$ 52,539.92	2	26,269.96	37,151.33	1.41	3,535.53	0	-
33	UXFR-2500-35-480-DL-T	2,500.0	\$ 60,714.69	1	60,714.69	60,714.69	1.00	2,500.00	0	-
34	UXFR-300-12-208-DL-N	300.0	\$ 914,694.00	50	18,293.88	129,357.27	7.07	2,121.32	0	-
35	UXFR-300-12-480-DL-N	300.0	\$ 242,983.72	14	17,355.98	64,940.13	3.74	1,122.50	0	-
36	UXFR-300-35-208-DL-N	300.0	\$ 430,074.67	17	25,298.51	104,308.43	4.12	1,236.93	0	-
37	UXFR-300-35-480-DL-N	300.0	\$ 173,268.76	7	24,752.68	65,489.44	2.65	793.73	0	-
38	UXFR-50-19-120-DL-H-N	50.0	\$ 977,955.03	117	8,358.59	90,411.97	10.82	540.83	1	117
39	UXFR-50-72-120-DL-H-N	50.0	\$ 2,303,799.54	458	5,030.13	107,649.48	21.40	1,070.05	1	458
40	UXFR-500-12-208-DL-N	500.0	\$ 1,130,511.72	52	21,740.61	156,773.77	7.21	3,605.55	0	-
41	UXFR-500-12-480-DL-T	500.0	\$ 1,237,507.62	57	21,710.66	163,911.89	7.55	3,774.92	0	-
42	UXFR-500-12-480-DL-T	500.0	\$ 65,131.98	3	21,710.66	37,603.97	1.73	866.03	0	-
43	UXFR-500-35-208-DL-N	500.0	\$ 520,840.73	17	30,637.69	126,322.43	4.12	2,061.55	0	-
44	UXFR-500-35-480-DL-T	500.0	\$ 29,659.85	1	29,659.85	29,659.85	1.00	500.00	0	-
45	UXFR-500-35-480-DL-T	500.0	\$ 771,156.10	26	29,659.85	151,236.15	5.10	2,549.51	0	-
46	UXFR-75-19-120-DL-H-N	75.0	\$ 333,148.14	39	8,542.26	53,346.40	6.24	468.37	0	-
47	UXFR-75-72-120-DL-H-N	75.0	\$ 811,149.04	104	7,799.51	79,539.71	10.20	764.85	0	-
48	UXFR-750-12-208-DL-N	750.0	\$ 795,396.00	15	53,026.40	205,370.36	3.87	2,904.74	0	-
49	UXFR-750-12-480-DL-T	750.0	\$ 1,155,271.60	40	28,881.79	182,664.48	6.32	4,743.42	0	-
50	UXFR-750-35-208-DL-N	750.0	\$ 58,664.46	1	58,664.46	58,664.46	1.00	750.00	0	-
51	UXFR-750-35-208-DL-N	750.0	\$ 117,328.92	2	58,664.46	82,964.07	1.41	1,060.66	0	-
52	UXFR-750-35-480-DL-T	750.0	\$ 146,973.08	4	36,743.27	73,486.54	2.00	1,500.00	0	-
53	UXFR-750-35-480-DL-T	750.0	\$ 367,432.70	10	36,743.27	116,192.42	3.16	2,371.71	0	-
54	UXFR-100-72-120-DL-L	100.0	\$ 74,647.50	10	7,464.75	23,605.61	3.16	316.23	0	-
55	UXFR-1000-12-208-DL-N	1,000.0	\$ 23,756.37	1	23,756.37	23,756.37	1.00	1,000.00	0	-
56	UXFR-1000-12-480-DL-T	1,000.0	\$ 32,580.96	1	32,580.96	32,580.96	1.00	1,000.00	0	-
57	UXFR-150-12-208-DL-N	150.0	\$ 65,011.70	5	13,002.34	29,074.12	2.24	335.41	0	-
58	UXFR-150-12-208-DL-N	150.0	\$ 13,002.34	1	13,002.34	13,002.34	1.00	150.00	0	-
59	UXFR-150-35-480-DL-N	150.0	\$ 10,949.80	1	10,949.80	10,949.80	1.00	150.00	0	-
60	UXFR-150-23-208-DR-N	150.0	\$ 7,230.15	1	7,230.15	7,230.15	1.00	150.00	0	-
61	UXFR-2500-35-12470-DL	2,500.0	\$ 26,269.96	1	26,269.96	26,269.96	1.00	2,500.00	0	-
62	UXFR-300-12-208-DL-N	300.0	\$ 54,881.64	3	18,293.88	31,685.93	1.73	519.62	0	-
63	UXFR-300-12-480-DL-N	300.0	\$ 17,355.98	1	17,355.98	17,355.98	1.00	300.00	0	-
64	UXFR-300-12-208-DL-N	300.0	\$ 73,175.52	4	18,293.88	36,587.76	2.00	600.00	0	-
65	UXFR-300-35-208-DL-N	300.0	\$ 25,298.51	1	25,298.51	25,298.51	1.00	300.00	0	-
66	UXFR-300-23-208-DR-N	300.0	\$ 18,575.45	1	18,575.45	18,575.45	1.00	300.00	0	-
67	UXFR-50-72-120-DL-H-N	37.5	\$ 25,150.65	5	5,030.13	11,247.71	2.24	83.85	1	5
68	UXFR-50-72-120-DL-H-N	50.0	\$ 5,030.13	1	5,030.13	5,030.13	1.00	50.00	1	1
69	UXFR-50-72-120-DL-H-N	50.0	\$ 10,060.26	2	5,030.13	7,113.68	1.41	70.71	1	2
70	UXFR-500-12-208-DL-N	500.0	\$ 86,962.44	4	21,740.61	43,481.22	2.00	1,000.00	0	-
71	UXFR-500-12-480-DL-T	500.0	\$ 130,263.96	6	21,710.66	53,180.04	2.45	1,224.74	0	-
72	UXFR-500-12-480-DL-T	500.0	\$ 21,710.66	1	21,710.66	21,710.66	1.00	500.00	0	-
73	UXFR-500-12-208-DL-N	500.0	\$ 21,740.61	1	21,740.61	21,740.61	1.00	500.00	0	-
74	UXFR-500-35-208-DL-N	500.0	\$ 91,913.07	3	30,637.69	53,066.04	1.73	866.03	0	-
75	UXFR-500-35-480-DL-T	500.0	\$ 59,319.70	2	29,659.85	41,945.36	1.41	707.11	0	-
76	UXFR-75-72-120-DL-H-N	75.0	\$ 15,599.02	2	7,799.51	11,030.17	1.41	106.07	0	-
77	UXFR-75-72-120-DL-H-N	75.0	\$ 148,190.69	19	7,799.51	33,997.28	4.36	326.92	0	-
78	UXFR-750-12-208-DL-N	750.0	\$ 106,052.80	2	53,026.40	74,990.65	1.41	1,060.66	0	-
79	UXFR-750-12-480-DL-T	750.0	\$ 28,881.79	1	28,881.79	28,881.79	1.00	750.00	0	-
80	UXFR-750-12-480-DL-T	750.0	\$ 57,763.58	2	28,881.79	40,845.02	1.41	1,060.66	0	-
81	UXFR-750-12-480-DL-T	750.0	\$ 28,881.79	1	28,881.79	28,881.79	1.00	750.00	0	-
82	UXFR-112-35-208-DL-N	112.5	\$ 18,238.44	1	18,238.44	18,238.44	1.00	112.50	0	-
83	UXFR-50-72-120-DL-H-N	50.0	\$ 15,090.39	3	5,030.13	8,712.44	1.73	86.60	1	3



Kentucky Power Company  
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Account 368 - Transformers

#	Description	Size	Cost	Quantity	Actual	Linear Regression Inputs			NARUC CAM	
					Unit Cost (\$ per Unit)	y*n^0.5	n^0.5	xn^0.5	Incl?	Qty
84	UXFR-5000-35-12470-D	5,000.0	\$ 187,523.85	3	62,507.95	108,266.95	1.73	8,660.25	0	-
85	UXFR-75-72-120-DL-H-N	75.0	\$ 7,799.51	1	7,799.51	7,799.51	1.00	75.00	0	-
86	UXFR-75-19-120-DL-H-N	75.0	\$ 17,084.52	2	8,542.26	12,080.58	1.41	106.07	0	-
87	CPD-PT-72	1.5	\$ 1,072.64	2	536.32	758.47	1.41	2.12	1	2
88	CPD-PT-72	1.5	\$ 2,681.60	5	536.32	1,199.25	2.24	3.35	1	5
89	CPD-PT-72	1.5	\$ 536.32	1	536.32	536.32	1.00	1.50	1	1
90	CPD-PT-19	1.5	\$ 904.85	1	904.85	904.85	1.00	1.50	1	1
91	CPD-PT-19	1.5	\$ 6,333.95	7	904.85	2,394.01	2.65	3.97	1	7
92	XFR-10-72-120-2B	10.0	\$ 9,249,556.91	5,357	1,726.63	126,374.69	73.19	731.92	1	5,357
93	XFR-10-72-120-2B	10.0	\$ 51,798.90	30	1,726.63	9,457.14	5.48	54.77	1	30
94	XFR-10-72-120-2B	10.0	\$ 1,726.63	1	1,726.63	1,726.63	1.00	10.00	1	1
95	XFR-10-199-120-1B	10.0	\$ 13,268.08	8	1,658.51	4,690.97	2.83	28.28	1	8
96	XFR-10-199-120-1B	10.0	\$ 1,658.51	1	1,658.51	1,658.51	1.00	10.00	1	1
97	XFR-10-199-240-2B	10.0	\$ 2,821.68	4	705.42	1,410.84	2.00	20.00	1	4
98	XFR-10-24-120-1B	10.0	\$ 7,144.72	11	649.52	2,154.21	3.32	33.17	1	11
99	XFR-10-24-120-1B	10.0	\$ 1,299.04	2	649.52	918.56	1.41	14.14	1	2
100	XFR-10-199-120-1B	10.0	\$ 3,025,122.24	1,824	1,658.51	70,832.16	42.71	427.08	1	1,824
101	XFR-10-199-277-1B	10.0	\$ 19,084.14	18	1,060.23	4,498.17	4.24	42.43	1	18
102	XFR-10-72-120-2B	10.0	\$ 2,327,497.24	1,348	1,726.63	63,393.43	36.72	367.15	1	1,348
103	XFR-10-72-240-2B	10.0	\$ 10,599.66	6	1,766.61	4,327.29	2.45	24.49	1	6
104	XFR-100-72-120-2B	100.0	\$ 5,448.04	1	5,448.04	5,448.04	1.00	100.00	0	-
105	XFR-100-72-120-2B	100.0	\$ 16,344.12	3	5,448.04	9,436.28	1.73	173.21	0	-
106	XFR-100-72-277-1B	100.0	\$ 1,060,457.20	220	4,820.26	71,496.01	14.83	1,483.24	0	-
107	XFR-100-72-120-2B	100.0	\$ 174,337.28	32	5,448.04	30,818.77	5.66	565.69	0	-
108	XFR-100-199-120-1B	100.0	\$ 352,584.42	123	2,866.54	31,791.47	11.09	1,109.05	0	-
109	XFR-100-199-240-2B	100.0	\$ 42,452.06	14	3,032.29	11,345.79	3.74	374.17	0	-
110	XFR-100-199-277-1B	100.0	\$ 10,208.20	2	5,104.10	7,218.29	1.41	141.42	0	-
111	XFR-100-24-120-1B	100.0	\$ 1,438.63	1	1,438.63	1,438.63	1.00	100.00	0	-
112	XFR-100-24-120-1B	100.0	\$ 14,386.30	10	1,438.63	4,549.35	3.16	316.23	0	-
113	XFR-100-199-120-1B	100.0	\$ 613,439.56	214	2,866.54	41,933.87	14.63	1,462.87	0	-
114	XFR-100-199-277-1B	100.0	\$ 632,908.40	124	5,104.10	56,836.85	11.14	1,113.55	0	-
115	XFR-100-199-277-1B	100.0	\$ 5,104.10	1	5,104.10	5,104.10	1.00	100.00	0	-
116	XFR-100-24-120-1B	100.0	\$ 5,754.52	4	1,438.63	2,877.26	2.00	200.00	0	-
117	XFR-100-72-120-2B	100.0	\$ 5,862,091.04	1,076	5,448.04	178,709.00	32.80	3,280.24	0	-
118	XFR-100-72-240-2B	100.0	\$ 117,078.90	30	3,902.63	21,375.58	5.48	547.72	0	-
119	XFR-100-72-277-1B	100.0	\$ 48,202.60	10	4,820.26	15,243.00	3.16	316.23	0	-
120	XFR-15-72-120-1B	15.0	\$ 1,539.15	1	1,539.15	1,539.15	1.00	15.00	1	1
121	XFR-15-72-120-1B	15.0	\$ 24,019,974.90	15,606	1,539.15	192,276.74	124.92	1,873.86	1	15,606
122	XFR-15-72-277-1B	15.0	\$ 237,012.02	146	1,623.37	19,615.25	12.08	181.25	1	146
123	XFR-15-199-120-1B	15.0	\$ 119,443.50	66	1,809.75	14,702.48	8.12	121.86	1	66
124	XFR-15-199-240-2B	15.0	\$ 1,691.48	2	845.74	1,196.06	1.41	21.21	1	2
125	XFR-15-24-120-1B	15.0	\$ 3,731.76	8	466.47	1,319.38	2.83	42.43	1	8
126	XFR-15-199-120-1B	15.0	\$ 8,732,043.75	4,825	1,809.75	125,709.25	69.46	1,041.93	1	4,825
127	XFR-15-199-277-1B	15.0	\$ 53,730.76	46	1,168.06	7,922.17	6.78	101.73	1	46
128	XFR-15-24-120-1B	15.0	\$ 3,265.29	7	466.47	1,234.16	2.65	39.69	1	7
129	XFR-15-24-120-1B	15.0	\$ 9,795.87	21	466.47	2,137.63	4.58	68.74	1	21
130	XFR-15-72-120-1B	15.0	\$ 3,366,121.05	2,187	1,539.15	71,978.92	46.77	701.48	1	2,187
131	XFR-15-72-240-2B	15.0	\$ 52,255.50	30	1,741.85	9,540.51	5.48	82.16	1	30
132	XFR-167-199-277-1B-T	167.0	\$ 694,375.04	127	5,467.52	61,615.82	11.27	1,881.99	0	-
133	XFR-167-199-120-1B	167.0	\$ 176,228.91	39	4,518.69	28,219.21	6.24	1,042.91	0	-
134	XFR-250-199-72-1B	167.0	\$ 84,109.80	15	5,607.32	21,717.06	3.87	646.79	0	-
135	XFR-167-72-120-2B	167.0	\$ 35,767.65	5	7,153.53	15,995.78	2.24	373.42	0	-
136	XFR-167-199-120-1B	167.0	\$ 180,747.60	40	4,518.69	28,578.70	6.32	1,056.20	0	-
137	XFR-167-199-277-1B-T	167.0	\$ 399,128.96	73	5,467.52	46,714.51	8.54	1,426.85	0	-
138	XFR-250-199-72-1B	167.0	\$ 510,266.12	91	5,607.32	53,490.42	9.54	1,593.08	0	-
139	XFR-167-72-120-2B	167.0	\$ 1,287,635.40	180	7,153.53	95,974.68	13.42	2,240.54	0	-
140	XFR-167-72-240-2B-B	167.0	\$ 96,555.21	29	3,329.49	17,929.85	5.39	899.32	0	-
141	XFR-167-72-277-1B	167.0	\$ 25,963.44	12	2,163.62	7,495.00	3.46	578.50	0	-
142	XFR-167-72-120-2B	167.0	\$ 14,307.06	2	7,153.53	10,116.62	1.41	236.17	0	-
143	XFR-167-72-24-2B-T	167.0	\$ 3,682.63	1	3,682.63	3,682.63	1.00	167.00	0	-
144	XFR-25-72-120-1B	25.0	\$ 9,860.25	5	1,972.05	4,409.64	2.24	55.90	1	5
145	XFR-25-72-120-1B	25.0	\$ 55,241,064.60	28,012	1,972.05	330,057.79	167.37	4,184.20	1	28,012
146	XFR-25-72-277-1B	25.0	\$ 779,572.78	406	1,920.13	38,689.55	20.15	503.74	1	406
147	XFR-25-72-120-1B	25.0	\$ 3,944.10	2	1,972.05	2,788.90	1.41	35.36	1	2
148	XFR-25-72-120-1B	25.0	\$ 1,972.05	1	1,972.05	1,972.05	1.00	25.00	1	1
149	XFR-25-199-120-1B	25.0	\$ 427,716.00	200	2,138.58	30,244.09	14.14	353.55	1	200
150	XFR-25-199-240-2B	25.0	\$ 1,591.41	1	1,591.41	1,591.41	1.00	25.00	1	1
151	XFR-25-199-240-2B	25.0	\$ 20,688.33	13	1,591.41	5,737.91	3.61	90.14	1	13
152	XFR-25-24-120-1B	25.0	\$ 19,265.49	23	837.63	4,017.13	4.80	119.90	1	23
153	XFR-25-24-120-1B	25.0	\$ 837.63	1	837.63	837.63	1.00	25.00	1	1
154	XFR-25-199-120-1B	25.0	\$ 2,138.58	1	2,138.58	2,138.58	1.00	25.00	1	1
155	XFR-25-199-120-1B	25.0	\$ 19,174,508.28	8,966	2,138.58	202,499.93	94.69	2,367.22	1	8,966
156	XFR-25-199-277-1B	25.0	\$ 532,884.38	254	2,097.97	33,436.14	15.94	398.43	1	254
157	XFR-25-199-120-1B	25.0	\$ 59,880.24	28	2,138.58	11,316.30	5.29	132.29	1	28
158	XFR-25-24-120-1B	25.0	\$ 41,881.50	50	837.63	5,922.94	7.07	176.78	1	50
159	XFR-25-24-277-1B	25.0	\$ 1,150.09	1	1,150.09	1,150.09	1.00	25.00	1	1
160	XFR-25-72-120-1B	25.0	\$ 6,302,671.80	3,196	1,972.05	111,486.25	56.53	1,413.33	1	3,196
161	XFR-25-72-240-2B	25.0	\$ 201,084.94	101	1,990.94	20,008.70	10.05	251.25	1	101
162	XFR-25-72-277-1B	25.0	\$ 19,201.30	10	1,920.13	6,071.98	3.16	79.06	1	10
163	XFR-25-72-120-1B	25.0	\$ 209,037.30	106	1,972.05	20,303.50	10.30	257.39	1	106
164	XFR-25-199-240-2B	25.0	\$ 1,591.41	1	1,591.41	1,591.41	1.00	25.00	1	1
165	XFR-250-72-277-1B	250.0	\$ 37,866.00	15	2,524.40	9,776.96	3.87	968.25	0	-
166	XFR-250-199-72-1B	250.0	\$ 5,607.32	1	5,607.32	5,607.32	1.00	250.00	0	-

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 368 - Transformers

#	Description	Size	Cost	Quantity	Actual	Linear Regression Inputs			NARUC CAM	
					Unit Cost (\$ per Unit)	y*n^0.5	n^0.5	xn^0.5	Incl?	Qty
167	XFR-250-199-72-1B	250.0	\$ 11,214.64	2	5,607.32	7,929.95	1.41	353.55	0	-
168	XFR-250-199-277-1B	250.0	\$ 28,638.78	6	4,773.13	11,691.73	2.45	612.37	0	-
169	XFR-250-199-72-1B	250.0	\$ 1,042,961.52	186	5,607.32	76,473.65	13.64	3,409.55	0	-
170	XFR-250-72-120-2B-T	250.0	\$ 45,603.24	12	3,800.27	13,164.52	3.46	866.03	0	-
171	XFR-250-72-120-2B-T	250.0	\$ 3,800.27	1	3,800.27	3,800.27	1.00	250.00	0	-
172	XFR-250-72-24-2B-T	250.0	\$ 12,278.84	4	3,069.71	6,139.42	2.00	500.00	0	-
173	XFR-250-72-277-1B	250.0	\$ 22,719.60	9	2,524.40	7,573.20	3.00	750.00	0	-
174	XFR-250-72-277-1B	250.0	\$ 7,573.20	3	2,524.40	4,372.39	1.73	433.01	0	-
175	CPD-PT-72	3.0	\$ 78,302.72	146	536.32	6,480.38	12.08	36.25	1	146
176	CPD-PT-72	3.0	\$ 536.32	1	536.32	536.32	1.00	3.00	1	1
177	CPD-PT-72	3.0	\$ 3,217.92	6	536.32	1,313.71	2.45	7.35	1	6
178	XFR-333-72-277-1B-T	333.0	\$ 65,981.28	8	8,247.66	23,327.91	2.83	941.87	0	-
179	XFR-333-199-277-1B	333.0	\$ 3,594.93	1	3,594.93	3,594.93	1.00	333.00	0	-
180	XFR-333-199-72-1B	333.0	\$ 40,302.30	3	13,434.10	23,268.54	1.73	576.77	0	-
181	XFR-333-72-277-1B-T	333.0	\$ 24,742.98	3	8,247.66	14,285.37	1.73	576.77	0	-
182	XFR-333-199-277-1B	333.0	\$ 10,784.79	3	3,594.93	6,226.60	1.73	576.77	0	-
183	XFR-333-199-72-1B	333.0	\$ 1,182,200.80	88	13,434.10	126,023.03	9.38	3,123.82	0	-
184	XFR-333-72-277-1B-T	333.0	\$ 41,238.30	5	8,247.66	18,442.33	2.24	744.61	0	-
185	XFR-333-72-277-1B-T	333.0	\$ 8,247.66	1	8,247.66	8,247.66	1.00	333.00	0	-
186	XFR-333-72-24-2B-T	333.0	\$ 30,442.77	3	10,147.59	17,576.14	1.73	576.77	0	-
187	XFR-37-72-120-1B	37.5	\$ 185,440.32	96	1,931.67	18,926.42	9.80	367.42	1	96
188	XFR-37-72-120-1B	37.5	\$ 17,385.03	9	1,931.67	5,795.01	3.00	112.50	1	9
189	XFR-37-72-277-1B	37.5	\$ 17,260.65	9	1,917.85	5,753.55	3.00	112.50	1	9
190	XFR-37-72-120-1B	37.5	\$ 1,813,838.13	939	1,931.67	59,192.37	30.64	1,149.12	1	939
191	XFR-37-24-120-1B	37.5	\$ 1,868.04	2	934.02	1,320.90	1.41	53.03	1	2
192	XFR-37-72-120-1B	37.5	\$ 1,931.67	1	1,931.67	1,931.67	1.00	37.50	1	1
193	XFR-37-24-120-1B	37.5	\$ 1,868.04	2	934.02	1,320.90	1.41	53.03	1	2
194	XFR-37-72-120-1B	37.5	\$ 983,220.03	509	1,931.67	43,580.46	22.56	846.04	1	509
195	XFR-10-72-120-2B	5.0	\$ 937,560.09	543	1,726.63	40,234.55	23.30	116.51	1	543
196	XFR-10-24-120-1B	5.0	\$ 1,299.04	2	649.52	918.56	1.41	7.07	1	2
197	XFR-10-72-120-2B	5.0	\$ 93,238.02	54	1,726.63	12,688.09	7.35	36.74	1	54
198	XFR-50-72-120-1B	50.0	\$ 2,815.22	1	2,815.22	2,815.22	1.00	50.00	1	1
199	XFR-50-72-120-1B	50.0	\$ 18,298,930.00	6,500	2,815.22	226,970.29	80.62	4,031.13	1	6,500
200	XFR-50-72-277-1B	50.0	\$ 960,876.93	403	2,384.31	47,864.69	20.07	1,003.74	1	403
201	XFR-50-72-120-1B	50.0	\$ 5,630.44	2	2,815.22	3,981.32	1.41	70.71	1	2
202	XFR-50-199-120-1B	50.0	\$ 347,994.90	135	2,577.74	29,950.63	11.62	580.95	1	135
203	XFR-50-199-240-2B	50.0	\$ 46,560.28	23	2,024.36	9,708.49	4.80	239.79	1	23
204	XFR-50-199-277-1B	50.0	\$ 10,652.40	6	1,775.40	4,348.82	2.45	122.47	1	6
205	XFR-50-24-120-1B	50.0	\$ 4,717.50	6	786.25	1,925.91	2.45	122.47	1	6
206	XFR-50-24-120-1B	50.0	\$ 786.25	1	786.25	786.25	1.00	50.00	1	1
207	XFR-50-199-120-1B	50.0	\$ 7,021,763.76	2,724	2,577.74	134,537.29	52.19	2,609.60	1	2,724
208	XFR-50-199-277-1B	50.0	\$ 399,465.00	225	1,775.40	26,631.00	15.00	750.00	1	225
209	XFR-50-199-277-1B	50.0	\$ 1,775.40	1	1,775.40	1,775.40	1.00	50.00	1	1
210	XFR-50-199-120-1B	50.0	\$ 123,731.52	48	2,577.74	17,859.11	6.93	346.41	1	48
211	XFR-50-24-120-1B	50.0	\$ 14,938.75	19	786.25	3,427.18	4.36	217.94	1	19
212	XFR-50-72-120-1B	50.0	\$ 2,815.22	1	2,815.22	2,815.22	1.00	50.00	1	1
213	XFR-50-72-120-1B	50.0	\$ 7,992,409.58	2,839	2,815.22	150,001.30	53.28	2,664.11	1	2,839
214	XFR-50-72-240-2B	50.0	\$ 59,429.76	24	2,476.24	12,131.05	4.90	244.95	1	24
215	XFR-50-72-240-2B	50.0	\$ 7,428.72	3	2,476.24	4,288.97	1.73	86.60	1	3
216	XFR-50-72-277-1B	50.0	\$ 33,380.34	14	2,384.31	8,921.27	3.74	187.08	1	14
217	XFR-50-72-240-2B	50.0	\$ 151,050.64	61	2,476.24	19,340.05	7.81	390.51	1	61
218	XFR-50-72-120-1B	50.0	\$ 185,804.52	66	2,815.22	22,870.96	8.12	406.20	1	66
219	XFR-500-72-277-1B-T	500.0	\$ 45,588.68	2	22,794.34	32,236.06	1.41	707.11	0	-
220	XFR-500-199-72-1B	500.0	\$ 96,616.80	6	16,102.80	39,443.64	2.45	1,224.74	0	-
221	XFR-500-199-24-2B-T	500.0	\$ 9,990.49	1	9,990.49	9,990.49	1.00	500.00	0	-
222	XFR-500-199-72-1B	500.0	\$ 32,205.60	2	16,102.80	22,772.80	1.41	707.11	0	-
223	XFR-500-24-277-1B-T	500.0	\$ 6,438.42	1	6,438.42	6,438.42	1.00	500.00	0	-
224	XFR-500-199-72-1B	500.0	\$ 16,102.80	1	16,102.80	16,102.80	1.00	500.00	0	-
225	XFR-500-199-72-2B-T	500.0	\$ 6,549,874.64	326	20,091.64	362,764.00	18.06	9,027.74	0	-
226	XFR-500-72-120-2B-T	500.0	\$ 13,399.04	2	6,699.52	9,474.55	1.41	707.11	0	-
227	XFR-500-72-24-2B-T	500.0	\$ 48,258.64	4	12,064.66	24,129.32	2.00	1,000.00	0	-
228	XFR-500-72-277-1B-T	500.0	\$ 68,383.02	3	22,794.34	39,480.96	1.73	866.03	0	-
229	XFR-500-199-72-2B-T	667.0	\$ 462,107.72	23	20,091.64	96,356.12	4.80	3,198.82	0	-
230	XFR-10-72-120-2B	7.5	\$ 1,726.63	1	1,726.63	1,726.63	1.00	7.50	1	1
231	XFR-10-72-120-2B	7.5	\$ 3,453.26	2	1,726.63	2,441.82	1.41	10.61	1	2
232	XFR-10-72-120-2B	7.5	\$ 3,453.26	2	1,726.63	2,441.82	1.41	10.61	1	2
233	XFR-75-72-277-1B	75.0	\$ 349,259.04	78	4,477.68	39,545.80	8.83	662.38	0	-
234	XFR-75-72-120-1B	75.0	\$ 124,334.18	31	4,010.78	22,331.08	5.57	417.58	0	-
235	XFR-75-199-120-1B	75.0	\$ 362,127.72	61	5,936.52	46,365.70	7.81	585.77	0	-
236	XFR-75-199-240-2B	75.0	\$ 9,153.78	6	1,525.63	3,737.02	2.45	183.71	0	-
237	XFR-75-24-120-2B	75.0	\$ 10,605.60	3	3,535.20	6,123.15	1.73	129.90	0	-
238	XFR-75-199-120-1B	75.0	\$ 403,683.36	68	5,936.52	48,953.80	8.25	618.47	0	-
239	XFR-75-199-277-1B	75.0	\$ 53,138.64	24	2,214.11	10,846.88	4.90	367.42	0	-
240	XFR-75-24-120-2B	75.0	\$ 14,140.80	4	3,535.20	7,070.40	2.00	150.00	0	-
241	XFR-75-24-277-1B	75.0	\$ 1,928.77	1	1,928.77	1,928.77	1.00	75.00	0	-
242	XFR-75-72-120-1B	75.0	\$ 2,943,912.52	734	4,010.78	108,661.79	27.09	2,031.93	0	-
243	XFR-75-72-240-2B	75.0	\$ 99,518.43	29	3,431.67	18,480.11	5.39	403.89	0	-
244	XFR-75-72-120-1B	75.0	\$ 4,010.78	1	4,010.78	4,010.78	1.00	75.00	0	-
245	XFR-833-199-72-2B-T	833.0	\$ 27,671.49	1	27,671.49	27,671.49	1.00	833.00	0	-

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 368 - Transformers

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs			NARUC CAM	
						y*n^0.5	n^0.5	xn^0.5	Incl?	Qty
246	XFR-833-199-72-2B-T	833.0	\$ 359,729.37	13	27,671.49	99,770.98	3.61	3,003.42	0	-
247	XFR-15-72-120-1B	15.0	\$ 18,469.80	12	1,539.15	5,331.77	3.46	51.96	1	12
248	XFR-500-199-72-2B-T	500.0	\$ 341,557.88	17	20,091.64	82,839.95	4.12	2,061.55	0	-
249	XFR-75-72-120-1B	75.0	\$ 4,010.78	1	4,010.78	4,010.78	1.00	75.00	0	-
250	XFR-75-24-277-1B	75.0	\$ 1,928.77	1	1,928.77	1,928.77	1.00	75.00	0	-
251	XFR-75-72-120-1B	75.0	\$ 4,010.78	1	4,010.78	4,010.78	1.00	75.00	0	-
252	TOTAL		\$ 224,337,806.85	94,482						89,194
253										
254	<u>Zero Intercept Linear Regression Results</u>					<u>LINEST Array</u>				
255										
256	Size Coefficient (\$ per MCM)		33.05264			33.05264	1,241.3494			
257	Zero Intercept (\$ per Unit)		1,241.34943			1.28330	98.3505			
258	R-Square		0.8483			0.84826	27,038.1162			
259										
260	<u>Plant Classification</u>									
261										
262	Total Number of Units	*	89,194							
263	Zero Intercept (\$/Unit)		\$ 1,241.35							
264	Minimum System (\$/Unit)		\$ 466.47							
265	Use Min System (M) or Zero Intercept (Z)?		Z							
266	Zero Intercept or Min System Cost (\$)		\$ 110,720,921							
267	Total Cost of Sample		\$ 224,337,807							
268	Percentage of Total		0.4935							
269	Percentage Classified as Customer-Related		49.35%							
270	Percentage Classified as Demand-Related		50.65%							

\* Only single-phase up to 50 KVA should be included  
in the Customer-related component per NARUC CAM

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 364 - Poles

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y^n^0.5	n^0.5	xn^0.5
1	10 Feet Wood Class 4	10.00	\$ 477.27	1	477.27	477.27	1.00	10.00
2	14 Feet FBGL Class N/A	14.00	\$ 30,729.20	34	903.80	5,270.01	5.83	81.63
3	15 Feet Pine Class 2	15.00	\$ 477.27	1	477.27	477.27	1.00	15.00
4	16 Feet Ornamental Class N/A	16.00	\$ 902.32	1	902.32	902.32	1.00	16.00
5	17 Feet Alumn Class N/A	17.00	\$ 121,813.20	135	902.32	10,484.01	11.62	197.52
6	17 Feet FBGL Class N/A	17.00	\$ 389,885.44	448	870.28	18,420.36	21.17	359.82
7	17 Feet Ornamental Class N/A	17.00	\$ 18,046.40	20	902.32	4,035.30	4.47	76.03
8	17 Feet Pine Class N/A	17.00	\$ 477.27	1	477.27	477.27	1.00	17.00
9	17 Feet Steel Class	17.00	\$ 25,264.96	28	902.32	4,774.63	5.29	89.96
10	20 Feet Alumn Class N/A	20.00	\$ 902.32	1	902.32	902.32	1.00	20.00
11	20 Feet Pine Class 0	20.00	\$ 2,863.62	6	477.27	1,169.07	2.45	48.99
12	20 Feet Pine Class 2	20.00	\$ 477.27	1	477.27	477.27	1.00	20.00
13	20 Feet Pine Class 3	20.00	\$ 954.54	2	477.27	674.96	1.41	28.28
14	20 Feet Pine Class 4	20.00	\$ 2,386.35	5	477.27	1,067.21	2.24	44.72
15	20 Feet Pine Class 5	20.00	\$ 6,204.51	13	477.27	1,720.82	3.61	72.11
16	20 Feet Pine Class 6	20.00	\$ 4,772.70	10	477.27	1,509.26	3.16	63.25
17	20 Feet Pine Class 7	20.00	\$ 17,181.72	36	477.27	2,863.62	6.00	120.00
18	20 Feet Pine Class 8	20.00	\$ 954.54	2	477.27	674.96	1.41	28.28
19	20 Feet Pine Class 9	20.00	\$ 477.27	1	477.27	477.27	1.00	20.00
20	20 Feet FBGL Class N/A	20.00	\$ 25,586.41	29	882.29	4,751.28	5.39	107.70
21	20 Feet Steel Class Unknown	20.00	\$ 1,804.64	2	902.32	1,276.07	1.41	28.28
22	20 Feet Unknown Class Unknown	20.00	\$ 1,431.81	3	477.27	826.66	1.73	34.64
23	20 Feet Unknown Class 4	20.00	\$ 477.27	1	477.27	477.27	1.00	20.00
24	20 Feet Wood Class 5	20.00	\$ 477.27	1	477.27	477.27	1.00	20.00
25	20 Feet Wood Class 7	20.00	\$ 477.27	1	477.27	477.27	1.00	20.00
26	20 Feet Wood Class Unknown	20.00	\$ 1,431.81	3	477.27	826.66	1.73	34.64
27	24 Feet Steel Class N/A	24.00	\$ 10,121.54	26	389.29	1,985.00	5.10	122.38
28	24 Feet FBGL Class N/A	24.00	\$ 2,793.18	3	931.06	1,612.64	1.73	41.57
29	25 Feet Aluminum Class N/A	25.00	\$ 3,724.24	4	931.06	1,862.12	2.00	50.00
30	25 Feet Pine Class 0	25.00	\$ 3,340.89	7	477.27	1,262.74	2.65	66.14
31	25 Feet Pine Class 1	25.00	\$ 954.54	2	477.27	674.96	1.41	35.36
32	25 Feet Pine Class 2	25.00	\$ 2,386.35	5	477.27	1,067.21	2.24	55.90
33	25 Feet Pine Class 3	25.00	\$ 954.54	2	477.27	674.96	1.41	35.36
34	25 Feet Pine Class 4	25.00	\$ 7,636.32	16	477.27	1,909.08	4.00	100.00
35	25 Feet Pine Class 5	25.00	\$ 30,545.28	64	477.27	3,818.16	8.00	200.00
36	25 Feet Pine Class 6	25.00	\$ 7,636.32	16	477.27	1,909.08	4.00	100.00
37	25 Feet Pine Class 7	25.00	\$ 21,477.15	45	477.27	3,201.62	6.71	167.71
38	25 Feet Pine Class Unknown	25.00	\$ 1,431.81	3	477.27	826.66	1.73	43.30
39	25 Feet Unknown Class 0	25.00	\$ 954.54	2	477.27	674.96	1.41	35.36
40	25 Feet Unknown Class Unknown	25.00	\$ 477.27	1	477.27	477.27	1.00	25.00
41	25 Feet Wood Class 2	25.00	\$ 477.27	1	477.27	477.27	1.00	25.00
42	25 Feet Wood Class 5	25.00	\$ 3,818.16	8	477.27	1,349.92	2.83	70.71
43	25 Feet Wood Class 7	25.00	\$ 477.27	1	477.27	477.27	1.00	25.00
44	25 Feet FBGL Class N/A	25.00	\$ 28,862.86	31	931.06	5,183.92	5.57	139.19
45	25 Feet Steel Class Unknown	25.00	\$ 16,007.36	4	4,001.84	8,003.68	2.00	50.00
46	30 Feet Alumnun Class Unknown	30.00	\$ 83,003.14	22	3,772.87	17,696.33	4.69	140.71
47	30 Feet Cedar Class 6	30.00	\$ 1,177.32	2	588.66	832.49	1.41	42.43
48	30 Feet Concrete Class 5	30.00	\$ 617.33	1	617.33	617.33	1.00	30.00
49	30 Feet Concrete Class 6	30.00	\$ 588.66	1	588.66	588.66	1.00	30.00
50	30 Feet Concrete Class N/A	30.00	\$ 389.29	1	389.29	389.29	1.00	30.00
51	30 Feet Douglas Fur Class 5	30.00	\$ 617.33	1	617.33	617.33	1.00	30.00
52	30 Feet Douglas Fur Class 6	30.00	\$ 588.66	1	588.66	588.66	1.00	30.00
53	30 Feet Fiberglass Class N/A	30.00	\$ 74,799.77	19	3,936.83	17,160.24	4.36	130.77
54	30 Feet Pine Class 0	30.00	\$ 13,637.70	18	757.65	3,214.44	4.24	127.28
55	30 Feet Pine Class 1	30.00	\$ 1,429.54	2	714.77	1,010.84	1.41	42.43
56	30 Feet Pine Class 2	30.00	\$ 14,834.82	22	674.31	3,162.79	4.69	140.71
57	30 Feet Pine Class 3	30.00	\$ 20,356.48	32	636.14	3,598.55	5.66	169.71
58	30 Feet Pine Class 4	30.00	\$ 290,723.68	472	615.94	13,381.64	21.73	651.77
59	30 Feet Pine Class 5	30.00	\$ 851,298.07	1,379	617.33	22,924.48	37.13	1,114.05
60	30 Feet Pine Class 6	30.00	\$ 19,835,487.36	33,696	588.66	108,057.20	183.56	5,506.94
61	30 Feet Pine Class 7	30.00	\$ 874,018.35	1,809	483.15	20,549.50	42.53	1,275.97
62	30 Feet Pine Class 8	30.00	\$ 9,663.00	20	483.15	2,160.71	4.47	134.16
63	30 Feet Pine Class 9	30.00	\$ 966.30	2	483.15	683.28	1.41	42.43
64	30 Feet Pine Class Unknown	30.00	\$ 4,321.31	7	617.33	1,633.30	2.65	79.37
65	30 Feet Ponderosa Pine Class 3	30.00	\$ 636.14	1	636.14	636.14	1.00	30.00
66	30 Feet Ponderosa Pine Class 4	30.00	\$ 615.94	1	615.94	615.94	1.00	30.00
67	30 Feet Ponderosa Pine Class 5	30.00	\$ 3,086.65	5	617.33	1,380.39	2.24	67.08
68	30 Feet Ponderosa Pine Class 6	30.00	\$ 176,009.34	299	588.66	10,178.88	17.29	518.75
69	30 Feet Ponderosa Pine Class 7	30.00	\$ 20,292.30	42	483.15	3,131.17	6.48	194.42
70	30 Feet Steel Class 5	30.00	\$ 389.29	1	389.29	389.29	1.00	30.00
71	30 Feet Steel Class 7	30.00	\$ 4,282.19	11	389.29	1,291.13	3.32	99.50
72	30 Feet Steel Class N/A	30.00	\$ 8,175.09	21	389.29	1,783.95	4.58	137.48

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 364 - Poles

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y*n^0.5	n^0.5	xn^0.5
73	30 Feet Unknown Class 5	30.00	\$ 617.33	1	617.33	617.33	1.00	30.00
74	30 Feet Unknown Class 6	30.00	\$ 15,305.16	26	588.66	3,001.59	5.10	152.97
75	30 Feet Unknown Class N/A	30.00	\$ 12,963.93	21	617.33	2,828.96	4.58	137.48
76	30 Feet Wood Class 0	30.00	\$ 2,272.95	3	757.65	1,312.29	1.73	51.96
77	30 Feet Wood Class 2	30.00	\$ 674.31	1	674.31	674.31	1.00	30.00
78	30 Feet Wood Class 3	30.00	\$ 636.14	1	636.14	636.14	1.00	30.00
79	30 Feet Wood Class 4	30.00	\$ 5,543.46	9	615.94	1,847.82	3.00	90.00
80	30 Feet Wood Class 5	30.00	\$ 19,754.56	32	617.33	3,492.15	5.66	169.71
81	30 Feet Wood Class 6	30.00	\$ 655,178.58	1,113	588.66	19,638.67	33.36	1,000.85
82	30 Feet Wood Class 7	30.00	\$ 16,427.10	34	483.15	2,817.22	5.83	174.93
83	30 Feet Wood Class Unknown	30.00	\$ 3,086.65	5	617.33	1,380.39	2.24	67.08
84	32 Feet Steel Class N/A	32.00	\$ 76,446.60	12	6,370.55	22,068.23	3.46	110.85
85	33 Feet Pine Class N/A	33.00	\$ 617.33	1	617.33	617.33	1.00	33.00
86	33 Feet Unknown Class N/A	33.00	\$ 6,173.30	10	617.33	1,952.17	3.16	104.36
87	35 Feet Aluminum Class N/A	35.00	\$ 281,617.58	107	2,631.94	27,225.00	10.34	362.04
88	35 Feet Cedar Class 6	35.00	\$ 1,712.07	3	570.69	988.46	1.73	60.62
89	35 Feet Douglas Fur Class 5	35.00	\$ 725.76	1	725.76	725.76	1.00	35.00
90	35 Feet Fiberglass Class N/A	35.00	\$ 4,461.36	1	4,461.36	4,461.36	1.00	35.00
91	35 Feet Pine Class 0	35.00	\$ 9,243.65	13	711.05	2,563.73	3.61	126.19
92	35 Feet Pine Class 1	35.00	\$ 9,954.70	14	711.05	2,660.51	3.74	130.96
93	35 Feet Pine Class 2	35.00	\$ 311,439.90	438	711.05	14,881.17	20.93	732.50
94	35 Feet Pine Class 3	35.00	\$ 83,951.40	94	893.10	8,658.93	9.70	339.34
95	35 Feet Pine Class 4	35.00	\$ 2,914,886.60	3,565	817.64	48,819.34	59.71	2,089.77
96	35 Feet Pine Class 5	35.00	\$ 23,209,079.04	31,979	725.76	129,785.29	178.83	6,258.94
97	35 Feet Pine Class 6	35.00	\$ 2,924,215.56	5,124	570.69	40,851.20	71.58	2,505.37
98	35 Feet Pine Class 7	35.00	\$ 506,943.93	945	536.45	16,490.89	30.74	1,075.93
99	35 Feet Pine Class 9	35.00	\$ 472.07	1	472.07	472.07	1.00	35.00
100	35 Feet Pine Class Unknown	35.00	\$ 725.76	1	725.76	725.76	1.00	35.00
101	35 Feet Ponderosa Pine Class 4	35.00	\$ 8,176.40	10	817.64	2,585.60	3.16	110.68
102	35 Feet Ponderosa Pine Class 5	35.00	\$ 145,877.76	201	725.76	10,289.42	14.18	496.21
103	35 Feet Ponderosa Pine Class 6	35.00	\$ 1,712.07	3	570.69	988.46	1.73	60.62
104	35 Feet Steel Class 6	35.00	\$ 9,563.04	3	3,187.68	5,521.22	1.73	60.62
105	35 Feet Steel Class 7	35.00	\$ 3,187.68	1	3,187.68	3,187.68	1.00	35.00
106	35 Feet Steel Class N/A	35.00	\$ 162,571.68	51	3,187.68	22,764.59	7.14	249.95
107	35 Feet Unknown Class 0	35.00	\$ 796.38	1	796.38	796.38	1.00	35.00
108	35 Feet Unknown Class 4	35.00	\$ 6,541.12	8	817.64	2,312.64	2.83	98.99
109	35 Feet Unknown Class 5	35.00	\$ 23,950.08	33	725.76	4,169.17	5.74	201.06
110	35 Feet Unknown Class 6	35.00	\$ 1,712.07	3	570.69	988.46	1.73	60.62
111	35 Feet Unknown Class 7	35.00	\$ 1,072.90	2	536.45	758.65	1.41	49.50
112	35 Feet Unknown Class N/A	35.00	\$ 1,141.38	2	570.69	807.08	1.41	49.50
113	35 Feet Wood Class 2	35.00	\$ 4,977.35	7	711.05	1,881.26	2.65	92.60
114	35 Feet Wood Class 3	35.00	\$ 7,965.36	9	885.04	2,655.12	3.00	105.00
115	35 Feet Wood Class 4	35.00	\$ 88,305.12	108	817.64	8,497.16	10.39	363.73
116	35 Feet Wood Class 5	35.00	\$ 600,203.52	827	725.76	20,871.12	28.76	1,006.52
117	35 Feet Wood Class 6	35.00	\$ 131,258.70	230	570.69	8,654.94	15.17	530.80
118	35 Feet Wood Class 7	35.00	\$ 11,801.87	22	536.45	2,516.17	4.69	164.16
119	35 Feet Wood Class 8	35.00	\$ 504.26	1	504.26	504.26	1.00	35.00
120	35 Feet Wood Class Unknown	35.00	\$ 2,452.92	3	817.64	1,416.19	1.73	60.62
121	40 Feet Cedar Class 1	40.00	\$ 4,455.52	4	1,113.88	2,227.76	2.00	80.00
122	40 Feet Cedar Class 2	40.00	\$ 4,494.16	4	1,123.54	2,247.08	2.00	80.00
123	40 Feet Cedar Class 4	40.00	\$ 1,791.18	2	895.59	1,266.56	1.41	56.57
124	40 Feet Concrete Class 2	40.00	\$ 4,883.17	1	4,883.17	4,883.17	1.00	40.00
125	40 Feet Douglas Fur Class 4	40.00	\$ 895.95	1	895.95	895.95	1.00	40.00
126	40 Feet Douglas Fur Class 5	40.00	\$ 837.72	1	837.72	837.72	1.00	40.00
127	40 Feet Douglas Fur Class 6	40.00	\$ 787.46	1	787.46	787.46	1.00	40.00
128	40 Feet Fiberglass Class N/A	40.00	\$ 8,891.46	6	1,481.91	3,629.92	2.45	97.98
129	40 Feet Pine Class 0	40.00	\$ 12,987.81	11	1,180.71	3,915.97	3.32	132.66
130	40 Feet Pine Class 1	40.00	\$ 33,416.40	30	1,113.88	6,100.97	5.48	219.09
131	40 Feet Pine Class 2	40.00	\$ 3,048,164.02	2,713	1,123.54	58,521.23	52.09	2,083.46
132	40 Feet Pine Class 3	40.00	\$ 344,065.05	345	997.29	18,523.84	18.57	742.97
133	40 Feet Pine Class 4	40.00	\$ 27,513,420.39	30,721	895.59	156,973.71	175.27	7,010.96
134	40 Feet Pine Class 5	40.00	\$ 16,896,812.40	20,170	837.72	118,973.94	142.02	5,680.85
135	40 Feet Pine Class 6	40.00	\$ 577,205.83	733	787.46	21,319.58	27.07	1,082.96
136	40 Feet Pine Class 7	40.00	\$ 36,270.26	49	740.21	5,181.47	7.00	280.00
137	40 Feet Pine Class H1	40.00	\$ 816.26	1	816.26	816.26	1.00	40.00
138	40 Feet Pine Class H2	40.00	\$ 1,314.49	1	1,314.49	1,314.49	1.00	40.00
139	40 Feet Pine Class Unknown	40.00	\$ 5,373.54	6	895.59	2,193.74	2.45	97.98
140	40 Feet Ponderosa Pine Class 2	40.00	\$ 3,370.62	3	1,123.54	1,946.03	1.73	69.28
141	40 Feet Ponderosa Pine Class 4	40.00	\$ 194,343.03	217	895.59	13,192.86	14.73	589.24
142	40 Feet Ponderosa Pine Class 5	40.00	\$ 139,061.52	166	837.72	10,793.27	12.88	515.36
143	40 Feet Steel Class 0	40.00	\$ 9,766.34	2	4,883.17	6,905.85	1.41	56.57
144	40 Feet Steel Class 6	40.00	\$ 4,883.17	1	4,883.17	4,883.17	1.00	40.00

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#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y^n^0.5	n^0.5	xn^0.5
145	40 Feet Steel Class N/A	40.00	\$ 864,321.09	177	4,883.17	64,966.35	13.30	532.17
146	40 Feet Unknown Class 0	40.00	\$ 1,258.36	1	1,258.36	1,258.36	1.00	40.00
147	40 Feet Unknown Class 2	40.00	\$ 4,494.16	4	1,123.54	2,247.08	2.00	80.00
148	40 Feet Unknown Class 4	40.00	\$ 21,494.16	24	895.59	4,387.48	4.90	195.96
149	40 Feet Unknown Class 5	40.00	\$ 12,565.80	15	837.72	3,244.48	3.87	154.92
150	40 Feet Unknown Class 6	40.00	\$ 787.46	1	787.46	787.46	1.00	40.00
151	40 Feet Unknown Class Unknown	40.00	\$ 11,642.67	13	895.59	3,229.10	3.61	144.22
152	40 Feet Wood Class 2	40.00	\$ 77,524.26	69	1,123.54	9,332.82	8.31	332.26
153	40 Feet Wood Class 3	40.00	\$ 12,964.77	13	997.29	3,595.78	3.61	144.22
154	40 Feet Wood Class 4	40.00	\$ 849,019.32	948	895.59	27,574.87	30.79	1,231.58
155	40 Feet Wood Class 5	40.00	\$ 540,329.40	645	837.72	21,275.45	25.40	1,015.87
156	40 Feet Wood Class 6	40.00	\$ 51,938.64	62	837.72	6,596.21	7.87	314.96
157	40 Feet Wood Class 7	40.00	\$ 1,480.42	2	740.21	1,046.81	1.41	56.57
158	40 Feet Wood Class Unknown	40.00	\$ 1,791.18	2	895.59	1,266.56	1.41	56.57
159	45 Feet Cedar Class 2	45.00	\$ 2,541.66	2	1,270.83	1,797.23	1.41	63.64
160	45 Feet Cedar Class 4	45.00	\$ 2,090.18	2	1,045.09	1,477.98	1.41	63.64
161	45 Feet Cedar Class H1	45.00	\$ 1,585.42	1	1,585.42	1,585.42	1.00	45.00
162	45 Feet Concrete Class 2	45.00	\$ 2,162.92	1	2,162.92	2,162.92	1.00	45.00
163	45 Feet Concrete Class N/A	45.00	\$ 2,162.92	1	2,162.92	2,162.92	1.00	45.00
164	45 Feet Pine Class 0	45.00	\$ 26,943.98	17	1,584.94	6,534.88	4.12	185.54
165	45 Feet Pine Class 1	45.00	\$ 115,132.71	77	1,495.23	13,120.59	8.77	394.87
166	45 Feet Pine Class 2	45.00	\$ 8,974,601.46	7,062	1,270.83	106,795.10	84.04	3,781.61
167	45 Feet Pine Class 3	45.00	\$ 766,244.40	680	1,126.83	29,384.13	26.08	1,173.46
168	45 Feet Pine Class 4	45.00	\$ 36,632,494.68	35,052	1,045.09	195,663.62	187.22	8,424.98
169	45 Feet Pine Class 5	45.00	\$ 3,669,910.02	3,723	985.74	60,146.30	61.02	2,745.74
170	45 Feet Pine Class 6	45.00	\$ 84,467.98	92	918.13	8,806.40	9.59	431.62
171	45 Feet Pine Class 7	45.00	\$ 4,315.21	5	863.04	1,929.82	2.24	100.62
172	45 Feet Pine Class H1	45.00	\$ 1,585.42	1	1,585.42	1,585.42	1.00	45.00
173	45 Feet Ponderosa Pine Class 2	45.00	\$ 33,041.58	26	1,270.83	6,479.99	5.10	229.46
174	45 Feet Ponderosa Pine Class 3	45.00	\$ 1,126.83	1	1,126.83	1,126.83	1.00	45.00
175	45 Feet Ponderosa Pine Class 4	45.00	\$ 203,792.55	195	1,045.09	14,593.89	13.96	628.39
176	45 Feet Ponderosa Pine Class 5	45.00	\$ 10,843.14	11	985.74	3,269.33	3.32	149.25
177	45 Feet Steel Class N/A	45.00	\$ 35,050.92	6	5,841.82	14,309.48	2.45	110.23
178	45 Feet Unknown Class 0	45.00	\$ 61,812.66	39	1,584.94	9,897.95	6.24	281.02
179	45 Feet Unknown Class 2	45.00	\$ 10,166.64	8	1,270.83	3,594.45	2.83	127.28
180	45 Feet Unknown Class 3	45.00	\$ 1,126.83	1	1,126.83	1,126.83	1.00	45.00
181	45 Feet Unknown Class 4	45.00	\$ 39,713.42	38	1,045.09	6,442.37	6.16	277.40
182	45 Feet Unknown Class 5	45.00	\$ 7,885.92	8	985.74	2,788.09	2.83	127.28
183	45 Feet Unknown Class Unknown	45.00	\$ 9,509.64	6	1,584.94	3,882.29	2.45	110.23
184	45 Feet Wood Class 1	45.00	\$ 4,485.69	3	1,495.23	2,589.81	1.73	77.94
185	45 Feet Wood Class 2	45.00	\$ 185,541.18	146	1,270.83	15,355.50	12.08	543.74
186	45 Feet Wood Class 3	45.00	\$ 13,521.96	12	1,126.83	3,903.45	3.46	155.88
187	45 Feet Wood Class 4	45.00	\$ 678,263.41	649	1,045.09	26,624.17	25.48	1,146.40
188	45 Feet Wood Class 5	45.00	\$ 165,604.32	168	985.74	12,776.65	12.96	583.27
189	45 Feet Wood Class 6	45.00	\$ 921.43	1	921.43	921.43	1.00	45.00
190	45 Feet Wood Class 7	45.00	\$ 871.00	1	871.00	871.00	1.00	45.00
191	45 Feet Wood Class Unknown	45.00	\$ 6,270.54	6	1,045.09	2,559.94	2.45	110.23
192	50 Feet Cedar Class 1	50.00	\$ 1,646.21	1	1,646.21	1,646.21	1.00	50.00
193	50 Feet Cedar Class 2	50.00	\$ 20,348.30	14	1,453.45	5,438.31	3.74	187.08
194	50 Feet Cedar Class 3	50.00	\$ 2,583.92	2	1,291.96	1,827.11	1.41	70.71
195	50 Feet Cedar Class 4	50.00	\$ 7,624.32	6	1,270.72	3,112.62	2.45	122.47
196	50 Feet Douglas Fur Class 2	50.00	\$ 4,360.35	3	1,453.45	2,517.45	1.73	86.60
197	50 Feet Douglas Fur Class 6	50.00	\$ 894.28	1	894.28	894.28	1.00	50.00
198	50 Feet Pine Class 1	50.00	\$ 293,025.38	178	1,646.21	21,963.18	13.34	667.08
199	50 Feet Pine Class 2	50.00	\$ 14,018,525.25	9,645	1,453.45	142,741.81	98.21	4,910.45
200	50 Feet Pine Class 3	50.00	\$ 2,104,602.84	1,629	1,291.96	52,144.63	40.36	2,018.04
201	50 Feet Pine Class 4	50.00	\$ 4,525,033.92	3,561	1,270.72	75,829.09	59.67	2,983.71
202	50 Feet Pine Class 5	50.00	\$ 37,103.04	39	951.36	5,941.24	6.24	312.25
203	50 Feet Pine Class 6	50.00	\$ 1,788.56	2	894.28	1,264.70	1.41	70.71
204	50 Feet Pine Class 7	50.00	\$ 1,640.76	2	820.38	1,160.19	1.41	70.71
205	50 Feet Pine Class H1	50.00	\$ 5,035.74	3	1,678.58	2,907.39	1.73	86.60
206	50 Feet Pine Class H2	50.00	\$ 2,288.47	1	2,288.47	2,288.47	1.00	50.00
207	50 Feet Pine Class N/A	50.00	\$ 1,291.69	1	1,291.69	1,291.69	1.00	50.00
208	50 Feet Ponderosa Pine Class 2	50.00	\$ 56,684.55	39	1,453.45	9,076.79	6.24	312.25
209	50 Feet Ponderosa Pine Class 3	50.00	\$ 6,459.80	5	1,291.96	2,888.91	2.24	111.80
210	50 Feet Ponderosa Pine Class 4	50.00	\$ 25,414.40	20	1,270.72	5,682.83	4.47	223.61
211	50 Feet Ponderosa Pine Class 5	50.00	\$ 951.36	1	951.36	951.36	1.00	50.00
212	50 Feet Ponderosa Pine Class 7	50.00	\$ 951.36	1	951.36	951.36	1.00	50.00
213	50 Feet Steel Class N/A	50.00	\$ 31,925.10	5	6,385.02	14,277.34	2.24	111.80
214	50 Feet Unknown Class 2	50.00	\$ 31,975.90	22	1,453.45	6,817.28	4.69	234.52
215	50 Feet Wood Class 0	50.00	\$ 1,584.94	1	1,584.94	1,584.94	1.00	50.00
216	50 Feet Wood Class 1	50.00	\$ 8,231.05	5	1,646.21	3,681.04	2.24	111.80

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Account 364 - Poles

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y^n^0.5	n^0.5	xn^0.5
217	50 Feet Wood Class 2	50.00	\$ 283,422.75	195	1,453.45	20,296.32	13.96	698.21
218	50 Feet Wood Class 3	50.00	\$ 12,919.60	10	1,291.96	4,085.54	3.16	158.11
219	50 Feet Wood Class 4	50.00	\$ 116,906.24	92	1,270.72	12,188.32	9.59	479.58
220	50 Feet Wood Class 5	50.00	\$ 2,854.08	3	951.36	1,647.80	1.73	86.60
221	50 Feet Wood Class 6	50.00	\$ 2,333.94	2	1,166.97	1,650.34	1.41	70.71
222	50 Feet Wood Class N/A	50.00	\$ 1,270.72	1	1,270.72	1,270.72	1.00	50.00
223	55 Feet Cedar Class 1	55.00	\$ 5,172.60	3	1,724.20	2,986.40	1.73	95.26
224	55 Feet Cedar Class 2	55.00	\$ 19,870.08	12	1,655.84	5,736.00	3.46	190.53
225	55 Feet Cedar Class 3	55.00	\$ 3,930.90	3	1,310.30	2,269.51	1.73	95.26
226	55 Feet Concrete Class 0	55.00	\$ 2,046.97	1	2,046.97	2,046.97	1.00	55.00
227	55 Feet Douglas Fur Class 1	55.00	\$ 1,724.20	1	1,724.20	1,724.20	1.00	55.00
228	55 Feet Pine Class 0	55.00	\$ 1,827.65	1	1,827.65	1,827.65	1.00	55.00
229	55 Feet Pine Class 1	55.00	\$ 174,144.20	101	1,724.20	17,328.00	10.05	552.74
230	55 Feet Pine Class 2	55.00	\$ 7,767,545.44	4,691	1,655.84	113,409.93	68.49	3,767.00
231	55 Feet Pine Class 3	55.00	\$ 367,878.40	235	1,565.44	23,997.74	15.33	843.13
232	55 Feet Pine Class 4	55.00	\$ 411,523.20	320	1,286.01	23,004.85	17.89	983.87
233	55 Feet Pine Class 5	55.00	\$ 23,733.19	20	1,186.66	5,306.90	4.47	245.97
234	55 Feet Pine Class 6	55.00	\$ 3,500.91	3	1,166.97	2,021.25	1.73	95.26
235	55 Feet Pine Class D	55.00	\$ 1,827.65	1	1,827.65	1,827.65	1.00	55.00
236	55 Feet Pine Class H1	55.00	\$ 22,485.10	11	2,044.10	6,779.51	3.32	182.41
237	55 Feet Pine Class H2	55.00	\$ 2,354.13	1	2,354.13	2,354.13	1.00	55.00
238	55 Feet Pine Class Unknown	55.00	\$ 1,655.84	1	1,655.84	1,655.84	1.00	55.00
239	55 Feet Pine Class Unset	55.00	\$ 1,655.84	1	1,655.84	1,655.84	1.00	55.00
240	55 Feet Ponderosa Pine Class 2	55.00	\$ 46,363.52	28	1,655.84	8,761.88	5.29	291.03
241	55 Feet Ponderosa Pine Class 3	55.00	\$ 1,565.44	1	1,565.44	1,565.44	1.00	55.00
242	55 Feet Ponderosa Pine Class 4	55.00	\$ 1,286.01	1	1,286.01	1,286.01	1.00	55.00
243	55 Feet Ponderosa Pine Class 5	55.00	\$ 1,208.85	1	1,208.85	1,208.85	1.00	55.00
244	55 Feet Steel Class 0	55.00	\$ 21,449.22	3	7,149.74	12,383.71	1.73	95.26
245	55 Feet Steel Class N/A	55.00	\$ 7,149.74	1	7,149.74	7,149.74	1.00	55.00
246	55 Feet Unknown Class 2	55.00	\$ 9,935.04	6	1,655.84	4,055.96	2.45	134.72
247	55 Feet Wood Class 1	55.00	\$ 6,896.80	4	1,724.20	3,448.40	2.00	110.00
248	55 Feet Wood Class 2	55.00	\$ 177,174.88	107	1,655.84	17,128.14	10.34	568.92
249	55 Feet Wood Class 3	55.00	\$ 10,958.08	7	1,565.44	4,141.76	2.65	145.52
250	55 Feet Wood Class 4	55.00	\$ 16,718.13	13	1,286.01	4,636.77	3.61	198.31
251	60 Feet Cedar Class 1	60.00	\$ 1,897.62	1	1,897.62	1,897.62	1.00	60.00
252	60 Feet Cedar Class 2	60.00	\$ 92,705.08	52	1,782.79	12,855.88	7.21	432.67
253	60 Feet Cedar Class 3	60.00	\$ 5,128.32	3	1,709.44	2,960.84	1.73	103.92
254	60 Feet Douglas Fur Class 2	60.00	\$ 12,479.53	7	1,782.79	4,716.82	2.65	158.75
255	60 Feet Douglas Fur Class 4	60.00	\$ 1,601.85	1	1,601.85	1,601.85	1.00	60.00
256	60 Feet Pine Class 1	60.00	\$ 134,731.02	71	1,897.62	15,989.63	8.43	505.57
257	60 Feet Pine Class 2	60.00	\$ 1,652,646.33	927	1,782.79	54,280.03	30.45	1,826.80
258	60 Feet Pine Class 3	60.00	\$ 52,992.64	31	1,709.44	9,517.76	5.57	334.07
259	60 Feet Pine Class 4	60.00	\$ 12,814.80	8	1,601.85	4,530.72	2.83	169.71
260	60 Feet Pine Class 5	60.00	\$ 1,601.85	1	1,601.85	1,601.85	1.00	60.00
261	60 Feet Pine Class 6	60.00	\$ 4,805.55	3	1,601.85	2,774.49	1.73	103.92
262	60 Feet Pine Class B	60.00	\$ 3,587.25	1	3,587.25	3,587.25	1.00	60.00
263	60 Feet Pine Class H1	60.00	\$ 4,367.12	2	2,183.56	3,088.02	1.41	84.85
264	60 Feet Pine Class H2	60.00	\$ 2,834.96	1	2,834.96	2,834.96	1.00	60.00
265	60 Feet Ponderosa Pine Class 2	60.00	\$ 8,913.95	5	1,782.79	3,986.44	2.24	134.16
266	60 Feet Steel Class N/A	60.00	\$ 3,587.25	1	3,587.25	3,587.25	1.00	60.00
267	60 Feet Unknown Class 2	60.00	\$ 3,565.58	2	1,782.79	2,521.25	1.41	84.85
268	60 Feet Wood Class 0	60.00	\$ 2,011.48	1	2,011.48	2,011.48	1.00	60.00
269	60 Feet Wood Class 1	60.00	\$ 1,897.62	1	1,897.62	1,897.62	1.00	60.00
270	60 Feet Wood Class 2	60.00	\$ 499,181.20	280	1,782.79	29,831.78	16.73	1,003.99
271	60 Feet Wood Class 3	60.00	\$ 51,283.20	30	1,709.44	9,362.99	5.48	328.63
272	60 Feet Wood Class 4	60.00	\$ 4,805.55	3	1,601.85	2,774.49	1.73	103.92
273	60 Feet Wood Class 6	60.00	\$ 3,203.70	2	1,601.85	2,265.36	1.41	84.85
274	60 Feet Wood Class 7	60.00	\$ 1,601.85	1	1,601.85	1,601.85	1.00	60.00
275	60 Feet Wood Class Unknown	60.00	\$ 2,056.18	1	2,056.18	2,056.18	1.00	60.00
276	65 Feet Cedar Class 1	65.00	\$ 4,055.36	2	2,027.68	2,867.57	1.41	91.92
277	65 Feet Cedar Class 2	65.00	\$ 48,535.08	22	2,206.14	10,347.71	4.69	304.88
278	65 Feet Cedar Class 3	65.00	\$ 2,206.14	1	2,206.14	2,206.14	1.00	65.00
279	65 Feet Cedar Class 5	65.00	\$ 1,949.34	1	1,949.34	1,949.34	1.00	65.00
280	65 Feet Pine Class 1	65.00	\$ 47,292.14	23	2,056.18	9,861.09	4.80	311.73
281	65 Feet Pine Class 2	65.00	\$ 598,165.60	295	2,027.68	34,826.55	17.18	1,116.41
282	65 Feet Pine Class 3	65.00	\$ 8,824.56	4	2,206.14	4,412.28	2.00	130.00
283	65 Feet Pine Class 4	65.00	\$ 8,295.08	4	2,073.77	4,147.54	2.00	130.00
284	65 Feet Pine Class H1	65.00	\$ 6,813.60	3	2,271.20	3,933.83	1.73	112.58
285	65 Feet Pine Class H3	65.00	\$ 3,757.83	1	3,757.83	3,757.83	1.00	65.00
286	65 Feet Ponderosa Pine Class 2	65.00	\$ 2,027.68	1	2,027.68	2,027.68	1.00	65.00
287	65 Feet Steel Class N/A	65.00	\$ 12,033.84	6	2,005.64	4,912.79	2.45	159.22
288	65 Feet Wood Class 1	65.00	\$ 8,224.72	4	2,056.18	4,112.36	2.00	130.00

Kentucky Power Company  
Zero Intercept & Minimum System Analyses

Account 364 - Poles

#	Description	Size	Cost	Quantity	Actual Unit Cost (\$ per Unit)	Linear Regression Inputs		
						y*n^0.5	n^0.5	xn^0.5
289	65 Feet Wood Class 2	65.00	\$ 377,148.48	186	2,027.68	27,653.87	13.64	886.48
290	65 Feet Wood Class 3	65.00	\$ 61,771.92	28	2,206.14	11,673.80	5.29	343.95
291	65 Feet Wood Class 4	65.00	\$ 4,147.54	2	2,073.77	2,932.75	1.41	91.92
292	65 Feet Wood Class 6	65.00	\$ 1,824.92	1	1,824.92	1,824.92	1.00	65.00
293	65 Feet Wood Class N/A	65.00	\$ 4,055.36	2	2,027.68	2,867.57	1.41	91.92
294	70 Feet Cedar Class 2	70.00	\$ 10,030.80	5	2,006.16	4,485.91	2.24	156.52
295	70 Feet Cedar Class 3	70.00	\$ 2,454.66	1	2,454.66	2,454.66	1.00	70.00
296	70 Feet Cedar Class H1	70.00	\$ 3,197.83	1	3,197.83	3,197.83	1.00	70.00
297	70 Feet Pine Class 1	70.00	\$ 18,388.44	6	3,064.74	7,507.05	2.45	171.46
298	70 Feet Pine Class 2	70.00	\$ 132,406.56	66	2,006.16	16,298.12	8.12	568.68
299	70 Feet Pine Class 3	70.00	\$ 9,818.64	4	2,454.66	4,909.32	2.00	140.00
300	70 Feet Pine Class 4	70.00	\$ 2,307.38	1	2,307.38	2,307.38	1.00	70.00
301	70 Feet Pine Class H1	70.00	\$ 6,395.66	2	3,197.83	4,522.41	1.41	98.99
302	70 Feet Cedar Class H1	70.00	\$ 3,197.83	1	3,197.83	3,197.83	1.00	70.00
303	70 Feet Wood Class 1	70.00	\$ 6,129.48	2	3,064.74	4,334.20	1.41	98.99
304	70 Feet Wood Class 2	70.00	\$ 110,338.80	55	2,006.16	14,878.08	7.42	519.13
305	70 Feet Wood Class 4	70.00	\$ 1,765.42	1	1,765.42	1,765.42	1.00	70.00
306	75 Feet Cedar Class 2	75.00	\$ 6,882.22	2	3,441.11	4,866.46	1.41	106.07
307	75 Feet Pine Class 1	75.00	\$ 5,348.18	2	2,674.09	3,781.73	1.41	106.07
308	75 Feet Pine Class 2	75.00	\$ 79,145.53	23	3,441.11	16,502.98	4.80	359.69
309	75 Feet Pine Class H2	75.00	\$ 3,389.70	1	3,389.70	3,389.70	1.00	75.00
310	75 Feet Unknown Class 2	75.00	\$ 3,441.11	1	3,441.11	3,441.11	1.00	75.00
311	75 Feet Wood Class 1	75.00	\$ 5,348.18	2	2,674.09	3,781.73	1.41	106.07
312	75 Feet Wood Class 2	75.00	\$ 147,967.73	43	3,441.11	22,564.87	6.56	491.81
313	75 Feet Wood Class 4	75.00	\$ 3,028.18	1	3,028.18	3,028.18	1.00	75.00
314	75 Feet Wood Class Unknown	75.00	\$ 6,882.22	2	3,441.11	4,866.46	1.41	106.07
315	80 Feet Cedar Class 2	80.00	\$ 2,981.63	1	2,981.63	2,981.63	1.00	80.00
316	80 Feet Douglas Fur Class 2	80.00	\$ 2,981.63	1	2,981.63	2,981.63	1.00	80.00
317	80 Feet Pine Class 2	80.00	\$ 8,944.89	3	2,981.63	5,164.33	1.73	138.56
318	80 Feet Pine Class 4	80.00	\$ 2,623.83	1	2,623.83	2,623.83	1.00	80.00
319	85 Feet Cedar Class 1	85.00	\$ 6,617.21	1	6,617.21	6,617.21	1.00	85.00
320	85 Feet Pine Class 2	85.00	\$ 56,183.85	9	6,242.65	18,727.95	3.00	255.00
321	85 Feet Pine Class 2	85.00	\$ 56,183.85	9	6,242.65	18,727.95	3.00	255.00
322	TOTAL		\$ 193,634,696.02	212,538				

**Zero Intercept Linear Regression Results**

**LINEST Array**

Size Coefficient (\$ per MCM)	38.02414	38.02414	(591.7000)
Zero Intercept (\$ per Unit)	(591.70000)	1.46138	58.6738
R-Square	0.9636	0.96358	4,767.1437

**Plant Classification**

Total Number of Units	212,538
Zero Intercept (\$/Unit)	\$ (591.70)
Minimum System (\$/Unit)	\$ 389.29
Use Min System (M) or Zero Intercept (Z)?	Z
Zero Intercept or Min System Cost (\$)	\$ (125,758,735)
Total Cost of Sample	\$ 193,634,696
Percentage of Total	-0.6495
Percentage Classified as Customer-Related	-64.95%
Percentage Classified as Demand-Related	164.95%



**Kentucky Power Company**  
**Zero Intercept & Minimum System Analyses**

**Zero Intercept Summary**

		<u>OH Primary</u>	<u>OH Secondary</u>	<u>UG Primary</u>	<u>UG Secondary</u>	<u>Transformers</u>	<u>Poles</u>
1	Customer Related	74.59%	40.93%	48.89%	36.29%	49.35%	-64.95%
2	Demand Related	25.41%	59.07%	51.11%	63.71%	50.65%	164.95%

Note: Result for poles is mathematically unreasonable.

**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 Certain Regulatory And Accounting    )  
Treatments; and (4) All Other Required Approvals    )  
And Relief                                                        )

Case No. 2025-00257

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**DIRECT TESTIMONY**

**OF**

**JOHN J. SPANOS**

**ON BEHALF OF**

**KENTUCKY POWER COMPANY**

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### **Attachments**

Exhibit JJS-1

Appendix A

## **I. INTRODUCTION**

1   **Q.   PLEASE STATE YOUR NAME AND ADDRESS.**

2   A.   My name is John J. Spanos. My business address is 300 Sterling Parkway,  
3       Mechanicsburg, Pennsylvania, 17050 (formerly 207 Senate Avenue, Camp Hill,  
4       Pennsylvania, 17011).

5   **Q.   ARE YOU ASSOCIATED WITH ANY FIRM?**

6   A.   Yes. I am associated with the firm of Gannett Fleming Valuation and Rate  
7       Consultants, LLC (“Gannett Fleming”).

8   **Q.   HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT**  
9       **FLEMING?**

10  A.   I have been associated with the firm since June 1986.

11  **Q.   WHAT IS YOUR POSITION WITH THE FIRM?**

12  A.   I am President.

13  **Q.   ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

14  A.   I am testifying on behalf of Kentucky Power Company (“Kentucky Power” or the  
15       “Company”).

16  **Q.   PLEASE STATE YOUR QUALIFICATIONS.**

17  A.   I have over 39 years of depreciation experience, which includes giving expert  
18       testimony in more than 500 cases before 47 regulatory commissions in the United  
19       States and Canada, including this Commission. The cases include depreciation  
20       studies in the electric, gas, water, wastewater, and pipeline industries. In addition  
21       to the cases where I have submitted testimony, I have supervised over 900 other  
22       depreciation or valuation assignments. Please refer to Appendix A for additional  
23       information on my qualifications, which includes further information with respect

1 to my work history, case experience, and my leadership in the Society of  
2 Depreciation Professionals.

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

5 A. My testimony will support and explain the depreciation study requested by the  
6 Company and conducted under my direction and supervision for Kentucky Power's  
7 electric utility plant. The study represents all electric plant assets.

## **II. DEPRECIATION STUDY**

8 **Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.**

9 A. Depreciation refers to the loss in service value not restored by current maintenance,  
10 incurred in connection with the consumption or prospective retirement of utility  
11 plant in the course of service from causes which are known to be in current  
12 operation, against which the Company is not protected by insurance. Among the  
13 causes to be given consideration are wear and tear, decay, action of the elements,  
14 obsolescence, changes in the art, changes in demand and the requirements of public  
15 authorities.

16 **Q. PLEASE IDENTIFY EXHIBIT JJS-1.**

17 A. Exhibit JJS-1 is a report entitled, "2025 Depreciation Study - Calculated Annual  
18 Depreciation Accruals Related to Electric Plant as of March 31, 2025." This report  
19 sets forth the results of my depreciation study for Kentucky Power (Depreciation  
20 Study).

1   **Q.    IS EXHIBIT JJS-1 A TRUE AND ACCURATE COPY OF YOUR**  
2       **DEPRECIATION STUDY?**

3    A.    Yes.

4   **Q.    DOES EXHIBIT JJS-1 ACCURATELY PORTRAY THE RESULTS OF**  
5       **YOUR DEPRECIATION STUDY AS OF MARCH 31, 2025?**

6    A.    Yes.

7   **Q.    WHAT WAS THE PURPOSE OF YOUR DEPRECIATION STUDY?**

8    A.    The purpose of the Depreciation Study was to estimate the annual depreciation  
9       accruals related to electric plant in service for ratemaking purposes and determine  
10      appropriate average service lives and net salvage percents for each plant account.

11   **Q.    PLEASE DESCRIBE THE CONTENTS OF YOUR REPORT.**

12   A.    The Depreciation Study is presented in nine parts. Part I, Introduction, presents the  
13      scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves,  
14      includes descriptions of the methodology of estimating survivor curves. Parts III  
15      and IV set forth the analysis for determining service life and net salvage estimates.  
16      Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of  
17      depreciation and amortization using the remaining life. Part VI, Results of Study,  
18      presents a description of the results of my analysis and a summary of the  
19      depreciation calculations. Parts VII, VIII, and IX include graphs and tables that  
20      relate to the service life and net salvage analyses, and the detailed depreciation  
21      calculations by account.

22               The Depreciation Study also includes several tables and tabulations of data  
23      and calculations. Table 1 on pages VI-4 and VI-5 of the Depreciation Study

1 presents the estimated survivor curve, the net salvage percent, the original cost as  
2 of March 31, 2025, the book depreciation reserve, and the calculated annual  
3 depreciation accrual and rate for each account or subaccount. The section  
4 beginning on page VII-2 presents the results of the retirement rate analyses  
5 prepared as the historical bases for the service life estimates. The section beginning  
6 on page VIII-2 presents the results of the net salvage analysis. The section  
7 beginning on page IX-2 presents the depreciation calculations related to surviving  
8 original cost as of March 31, 2025.

9 **Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION**  
10 **STUDY.**

11 A. I used the straight line remaining life method of depreciation, with the average  
12 service life procedure for all plant assets except some general plant accounts. The  
13 annual depreciation is based on a method of depreciation accounting that seeks to  
14 distribute the unrecovered cost of fixed capital assets over the estimated remaining  
15 useful life of each unit, or group of assets, in a systematic and rational manner.

16 For General Plant Accounts 391.00, 392.00, 393.00, 394.00, 395.00,  
17 396.00, 397.10, 397.21, 397.30 and 398.00, I used the straight line remaining life  
18 method of amortization<sup>1</sup>. The annual amortization is based on amortization  
19 accounting that distributes the unrecovered cost of fixed capital assets over the  
20 remaining amortization period selected for each account and vintage.

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<sup>1</sup> With the conversion to FERC Order 898, general plant amortization will also be applicable to the following FERC Order 898 Accounts: 315.10, 315.11, 315.21, 315.22, 315.31, 315.32, 324.1, 324.21, 324.3, 334.1, 334.21, 334.3, 338.1, 338.11, 338.23, 338.3, 338.31, 338.9, 339.101, 339.11, 339.9, 345.11, 345.2, 345.3, 351.1, 351.2, 351.3, 351.36, 363.1, 363.2, 363.3, 363.36, 387.1, 387.8, 387.9, 397.1, 397.21 and 397.3.

1   **Q.   HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL**  
2       **DEPRECIATION ACCRUAL RATES?**

3   A.   I did this in two phases. In the first phase, I estimated the service life and net salvage  
4       characteristics for each depreciable group, that is, each plant account or subaccount  
5       identified as having similar characteristics. In the second phase, I calculated the  
6       composite remaining lives and annual depreciation accrual rates based on the  
7       service life and net salvage estimates determined in the first phase.

8   **Q.   PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION**  
9       **STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET**  
10      **SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.**

11 A.   The service life and net salvage study consisted of compiling historical data from  
12      records related to Kentucky Power's plant; analyzing this data to obtain historical  
13      trends of survivor and net salvage characteristics; obtaining supplementary  
14      information from Kentucky Power's management, and operating personnel  
15      concerning practices and plans as they relate to plant operations; and interpreting  
16      the above data and the estimates used by other electric utilities to form judgments  
17      of average service life and net salvage characteristics.

18 **Q.   WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE**  
19      **OF ESTIMATING SERVICE LIFE CHARACTERISTICS?**

20 A.   For generation accounts, I analyzed the Company's accounting entries that record  
21      plant transactions during the period 1999 through 2024. For the remaining plant  
22      accounts, I analyzed the Company's accounting entries during the period 1954  
23      through 2024 to the extent available as for some of the larger distribution accounts



1 the earliest year of actuarial data varied. The transactions included additions,  
2 retirements, transfers and the related balances. The Company records also included  
3 surviving dollar value by year installed for each plant account as of March 31, 2025.

4 **Q. WHAT METHOD DID YOU USE TO ANALYZE THESE SERVICE LIFE**  
5 **DATA?**

6 A. I used the retirement rate method. This is the most appropriate method when aged  
7 retirement data are available, because this method determines the average rates of  
8 retirement actually experienced by the Company during the period of time covered  
9 by the study.

10 **Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE**  
11 **METHOD TO ANALYZE KENTUCKY POWER'S SERVICE LIFE DATA.**

12 A. I applied the retirement rate method to each different group of property in the study.  
13 For each property group, I used the retirement rate method to form a life table  
14 which, when plotted, shows an original survivor curve for that property group.  
15 Each original survivor curve represents the average survivor pattern experienced  
16 by the several vintage groups during the experience band studied. The survivor  
17 patterns do not necessarily describe the life characteristics of the property group;  
18 therefore, interpretation of the original survivor curves is required in order to use  
19 them as valid considerations in estimating service life. The Iowa-type survivor  
20 curves were used to perform these interpretations.

1    **Q.    WHAT IS AN “IOWA-TYPE SURVIVOR CURVE” AND HOW DID YOU**  
2           **USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE**  
3           **CHARACTERISTICS FOR EACH PROPERTY GROUP?**

4    A.    Iowa-type curves are a widely used group of generalized survivor curves that  
5           contain the range of survivor characteristics usually experienced by utilities and  
6           other industrial companies. The Iowa curves were developed at the Iowa State  
7           College Engineering Experiment Station through an extensive process of observing  
8           and classifying the ages at which various types of property used by utilities and  
9           other industrial companies had been retired.

10                Iowa-type curves are used to smooth and extrapolate original survivor  
11           curves determined by the retirement rate method. The Iowa curves and truncated  
12           Iowa curves were used in this study to describe the forecasted rates of retirement  
13           based on the observed rates of retirement and the outlook for future retirements.

14                The estimated survivor curve designations for each depreciable property  
15           group indicate the average service life, the family within the Iowa system to which  
16           the property group belongs, and the relative height of the mode. For example, the  
17           Iowa 50-R1.5 indicates an average service life of 50 years; a right-moded, or R,  
18           type curve (the mode occurs after average life for right-moded curves); and a low  
19           height, 1.5, for the mode (possible modes for R type curves range from 0.5 to 5).

20   **Q.    WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF**  
21           **SIGNIFICANT PRODUCTION FACILITIES?**

22    A.    I used the life span technique to estimate the lives of significant facilities for which  
23           concurrent retirement of the entire facility is anticipated. In this technique, the

1 survivor characteristics of such facilities are described by the use of interim  
2 survivor curves and estimated probable retirement dates. The interim survivor  
3 curve describes the rate of retirement related to the replacement of elements of the  
4 facility, such as, for a power plant, the retirement of assets such as pumps, motors  
5 and piping that occur during the life of the facility. The probable retirement date  
6 provides the rate of final retirement for all installations at the facility by truncating  
7 the interim survivor curve for each installation year at its attained age at the date of  
8 probable retirement. The use of interim survivor curves truncated at the date of  
9 probable retirement provides a consistent method for estimating the lives of  
10 installations for a particular facility inasmuch as a single concurrent retirement for  
11 all years of installation will occur when it is retired.

12 **Q. IS THIS APPROACH WIDELY ACCEPTED FOR ESTIMATING THE**  
13 **SERVICE LIVES OF PRODUCTION FACILITIES?**

14 A. Yes. The life span technique has been used previously for Kentucky Power. My  
15 firm has also used the life span technique in performing depreciation studies  
16 presented to many other public utility commissions across the United States and  
17 Canada.

18 **Q. HOW ARE THE LIFE SPANS ESTIMATED FOR KENTUCKY POWER'S**  
19 **PRODUCTION FACILITIES?**

20 A. The life span estimates are based on informed judgment that incorporates factors  
21 for each facility such as the technology of the facility, management plans and  
22 outlook for the facility, and the estimates for similar facilities for other utilities.

1    **Q.    ARE THE NEW LIFE SPANS WITHIN INDUSTRY EXPECTATIONS?**

2    A.    Yes. However, the life spans are on the longer end of the current industry  
3           expectations. The life span for the Big Sandy Plant is 78 years and for the Mitchell  
4           Plant is 69 years. As presented on page III-5 of Exhibit JJS-1, Big Sandy was  
5           placed in service in 1963 and has a probable retirement date of 2041 while Mitchell  
6           was placed in service in 1971 and has a probable retirement date of 2040. These  
7           life spans are on the long end compared to similar units but are still reasonable for  
8           these facilities given the Company's current plans to run the Big Sandy Plant  
9           through 2041 and the Mitchell Plant through 2040. The most common range of life  
10          spans for steam production facilities had been 55 to 65 years; however, in recent  
11          years, originally proposed life spans have been shortened due to unit efficiencies  
12          and environmental regulations. The industry average of similar units in recent years  
13          has been 46 years. Consequently, these life spans are on the longer end but are still  
14          reasonable given the plans of operation and expectations for meeting generation  
15          demands.

16   **Q.    ARE THE FACTORS CONSIDERED IN YOUR ESTIMATES OF SERVICE**  
17   **LIFE AND NET SALVAGE PERCENTS PRESENTED IN EXHIBIT JJS-1?**

18   A.    Yes. A discussion of the factors considered in the estimation of service lives and  
19          net salvage percents are presented in Part III and Part IV of Exhibit JJS-1.

20   **Q.    HAVE YOU PHYSICALLY OBSERVED KENTUCKY POWER'S PLANT**  
21   **AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDIES?**

22   A.    Yes. There was a field review made of Kentucky Power's property during  
23          December 2024 to observe representative portions of plant. Additionally, I had

1 conducted a field visit in 2023. Field reviews are conducted to become familiar  
2 with Company operations and obtain an understanding of the function of the plant  
3 and information with respect to the reasons for past retirements and the expected  
4 future causes of retirements. This knowledge was incorporated in the interpretation  
5 and extrapolation of the statistical analyses.

6 **Q. WOULD YOU PLEASE EXPLAIN THE CONCEPT OF “NET SALVAGE?”**

7 A. Net salvage is a component of the service value of capital assets that is recovered  
8 through depreciation rates. The service value of an asset is its original cost less its  
9 net salvage. Net salvage is the gross salvage value received for the asset upon  
10 retirement less the cost to retire the asset. When the cost to retire exceeds the gross  
11 salvage value, the result is negative net salvage.

12 Inasmuch as depreciation expense is the loss in service value of an asset  
13 during a defined period, *e.g.*, one year, it must include a ratable portion of both the  
14 original cost and the net salvage. That is, the net salvage related to an asset should  
15 be incorporated in the cost-of-service during the same period as its original cost so  
16 that customers receiving service from the asset pay rates that include a portion of  
17 both elements of the asset’s service value, the original cost, and the net salvage  
18 value.

19 For example, the full recovery of the service value of a \$20,000 circuit  
20 breaker will include not only the \$20,000 of original cost, but also, on average,  
21 \$3,500 to remove the circuit breaker at the end of its life and \$500 in salvage value.  
22 In this example, the net salvage component is negative \$3,000 (\$500-\$3,500), and  
23 the net salvage percent is negative 15%  $((\$500-\$3,500)/\$20,000)$ .

1   **Q.   PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE**  
2       **PERCENTAGES.**

3   A.   The net salvage percentages estimated in the Depreciation Study were based on  
4       informed judgment that incorporated factors such as the statistical analyses of  
5       historical net salvage data; information provided to me by the Company's operating  
6       personnel, general knowledge and experience of the industry practices; and trends  
7       in the industry in general. The statistical net salvage analyses incorporate the  
8       Company's actual historical data for the period 2000 through 2024 for generation,  
9       transmission, distribution, and general plant accounts, and consider the cost of  
10      removal and gross salvage ratios to the associated retirements during the 25-year  
11      period. Trends of these data are also measured based on three-year moving  
12      averages and the most recent five-year indications.

13   **Q.   WERE THE NET SALVAGE PERCENTAGES FOR GENERATING**  
14       **FACILITIES BASED ON THE SAME ANALYSES?**

15   A.   Yes, for the interim net salvage estimates. The net salvage percentages for  
16       generating facilities were based on two components, the interim net salvage  
17       percentage and the final net salvage percentage. The interim net salvage percentage  
18       is determined based on the historical indications from the period 2000 to 2024 of  
19       the cost of removal and gross salvage amounts as a percentage of the associated  
20       plant retired. The final net salvage or dismantlement component was determined  
21       based on the retirement activities associated with the assets anticipated to be retired  
22       at the concurrent date of final retirement.

1   **Q.    HAVE YOU INCLUDED A DISMANTLEMENT OR DECOMMISSIONING**  
2       **COMPONENT INTO THE OVERALL RECOVERY OF GENERATING**  
3       **FACILITIES?**

4   A.    Yes. A dismantlement or decommissioning component has been included in the  
5       net salvage percentage for steam production facilities.

6   **Q.    CAN YOU EXPLAIN HOW THE FINAL NET SALVAGE COMPONENT IS**  
7       **INCLUDED IN THE DEPRECIATION STUDY?**

8   A.    Yes. The dismantlement component is part of the overall net salvage for each  
9       location within the steam production assets. Based on studies for other utilities and  
10      the Decommissioning Costs established by Kentucky Power, it was determined that  
11      the dismantlement or decommissioning costs for steam production facilities is best  
12      calculated by dividing the dismantlement cost by the surviving plant at final  
13      retirement. These amounts at a location basis are weighted with the interim net  
14      salvage percentage of the assets anticipated to be retired on an interim basis to  
15      produce an overall net salvage percentage for each location. The detailed  
16      calculations of the overall, or weighted, net salvage for each location are set forth  
17      on page VIII-2 of the Depreciation Study.

18   **Q.    WHAT IS THE BASIS OF THE DISMANTLEMENT OR**  
19       **DECOMMISSIONING COST ESTIMATES?**

20   A.    The decommissioning cost estimates were developed from decommissioning  
21       studies of each generating site performed by Kentucky Power. These estimates  
22       were based on the cost to decommission the facility as of the date of the study then  
23       escalated to the probable retirement date. The costs to decommission power plants

1           have tended to increase over time (as have construction costs in general). For this  
2           reason, in order to recover the full decommissioning costs for each site, these costs  
3           need to be escalated to the time of retirement.

4   **Q.   SHOULD NET SALVAGE BE BASED ON THE FUTURE COSTS**  
5       **EXPECTED TO BE INCURRED, NOT ON TODAY'S COSTS?**

6   A.   Yes. Because net salvage must be based on future costs, decommissioning costs  
7       for net salvage must also be estimates of the future cost at the time of  
8       decommissioning. For this reason, if decommissioning estimates are developed  
9       using the cost to decommission a plant today, then these costs must be escalated to  
10      the time period in which they are expected to be incurred to achieve adequate  
11      recovery.

12   **Q.   SHOULD NET SALVAGE BE RECOVERED IN TODAY'S COST (THAT IS,**  
13       **THE COST IN TODAY'S DOLLARS)?**

14   A.   No. In order to recover the service value of the Company's assets, net salvage must  
15       be determined at the cost that will be incurred in the future. When using the straight  
16       line method of depreciation, these costs are recovered ratably, or in equal amounts  
17       each year, over the life of the Company's plant.



1    **Q.    IS RECOVERING THE FUTURE COST OF NET SALVAGE CONSISTENT**  
2           **WITH THE FEDERAL ENERGY REGULATORY COMMISSION’S**  
3           **UNIFORM SYSTEM OF ACCOUNTS (FERC USOA)?**

4    A.    Yes. The FERC USOA specifically defines net salvage as follows:

5                   19. Net salvage value means the salvage value of property retired  
6                   less the cost of removal.

7           Cost of removal is defined as:

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

15          Finally, cost is defined as (emphasis added):

16                  9. Cost means the amount of money actually paid for property or  
17                  services. When the consideration given is other than cash in a  
18                  purchase and sale transaction, as distinguished from a transaction  
19                  involving the issuance of common stock in a merger or a pooling of  
20                  interest, the value of such consideration shall be determined on a  
21                  cash basis.

22          Read together, it should be clear from these definitions that the USOA specifies  
23          cost of removal, as part of net salvage, must be recovered through depreciation  
24          expense and is the actual amount paid at the time of the transaction. Because net  
25          salvage will occur in the future, it is an estimate of the future cost that must be  
26          included in depreciation rates.

1   **Q.   DO GENERALLY ACCEPTED DEPRECIATION CONCEPTS SUPPORT**  
2       **THE CONCEPT THAT THE NET SALVAGE IN DEPRECIATION**  
3       **SHOULD BE INCLUDED AT THE COST THAT WILL BE INCURRED?**

4   A.   Yes. Including the future cost of net salvage for plant accounts is consistent with  
5       established depreciation concepts. Depreciation is a cost allocation concept, in  
6       which the full cost of an asset (original cost less net salvage) is allocated on a  
7       straight line basis over the period of time an asset will be in service.

8   **Q.   DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT THAT**  
9       **THE NET SALVAGE AMOUNT SHOULD REPRESENT THE FUTURE**  
10      **COST?**

11 A.   Yes. Two preeminent depreciation texts are the National Association of Regulatory  
12      Utility Commissioners' (typically referred to as "NARUC") *Public Utility*  
13      *Depreciation Practices* and *Depreciation Systems* by Wolf and Fitch (Wolf and  
14      Fitch). Both texts are clear that net salvage should be included in depreciation as a  
15      future cost. NARUC states the following:

16                   [U]nder presently accepted concepts, the amount of depreciation to  
17                   be accrued over the life of an asset is its original cost less net  
18                   salvage. Net salvage is the difference between the gross salvage that  
19                   will be realized when the asset is disposed of and the cost of retiring  
20                   it.<sup>2</sup> (Emphasis added)

21      NARUC also explains that:

22                   The goal of accounting for net salvage is to allocate the net cost of  
23                   an asset to accounting periods, making due allowance for the net  
24                   salvage, positive or negative, that will be obtained when the asset is  
25                   retired. This concept carries with it the premise that property  
26                   ownership includes the responsibility for the property's ultimate  
27                   abandonment or removal. Hence, if users benefit from its use, they  
28                   should pay their pro rata share of the costs involved in the

---

<sup>2</sup>NARUC Manual at 18.

1                    abandonment or removal of the property and also receive their pro  
2                    rata share of the benefits of the proceeds received.<sup>3</sup> (Emphasis  
3                    added)

4                    Wolf and Fitch explain that:

5                    The matching principle specifies that all cost incurred to produce a  
6                    service should be matched against the revenue produced. Estimated  
7                    future costs of retiring an asset currently in service must be accrued  
8                    and allocated as part of the current expenses.<sup>4</sup>

9                    **Q.     PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT**  
10                   **YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU**  
11                   **CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL**  
12                   **DEPRECIATION ACCRUAL RATES.**

13                  A.     After I estimated the service life and net salvage characteristics for each depreciable  
14                   property group, I calculated the annual depreciation accrual rates for each  
15                   depreciable group based on the straight line remaining life method, using remaining  
16                   lives weighted consistent with the average service life procedure. The calculation  
17                   of annual depreciation accrual rates was developed as of March 31, 2025.

18                  **Q.     PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE**  
19                   **METHOD OF DEPRECIATION.**

20                  A.     The straight line remaining life method of depreciation allocates the original cost  
21                   of the property, less accumulated depreciation, less future net salvage, in equal  
22                   amounts to each year of remaining service life.

---

<sup>3</sup> NARUC Manual at 18.

<sup>4</sup> Wolf and Fitch, p. 7.

1   **Q.     PLEASE DESCRIBE THE AVERAGE SERVICE LIFE PROCEDURE FOR**  
2       **CALCULATING REMAINING LIFE ACCRUAL RATES.**

3   A.    The average service life procedure defines the group or account for which the  
4       remaining life annual accrual is determined. Under this procedure, the annual  
5       accrual rate is determined for the entire group or account based on its average  
6       remaining life and the rate is then applied to the surviving balance of the group's  
7       cost. The average remaining life of the group is calculated by first dividing the  
8       future book accruals (original cost less allocated book reserve less future net  
9       salvage) by the average remaining life for each vintage. The average remaining life  
10      for each vintage is derived from the area under the survivor curve between the  
11      attained age of the vintage and the maximum age. The sum of the future book  
12      accruals is then divided by the sum of the annual accruals to determine the average  
13      remaining life of the entire group for use in calculating the annual depreciation  
14      accrual rate. This calculation is further detailed in Part V of Exhibit JJS-1.

15   **Q.     PLEASE DESCRIBE AMORTIZATION ACCOUNTING.**

16   A.    Amortization accounting is used for accounts with a large number of units, but  
17      small asset values. In amortization accounting, units of property are capitalized in  
18      the same manner as they are in depreciation accounting. However, depreciation  
19      accounting is difficult for these assets because periodic inventories are required to  
20      properly reflect plant in service. Consequently, retirements are recorded when a  
21      vintage is fully amortized rather than as the units are removed from service. That  
22      is, there is no dispersion of retirement. All units are retired when the age of the  
23      vintage reaches the amortization period. Each plant account or group of assets is

1 assigned a fixed period which represents an anticipated life during which the asset  
2 will render service. For example, in amortization accounting, assets that have a  
3 15-year amortization period will be fully recovered after 15 years of service and  
4 taken off the Company books, but not necessarily removed from service. In  
5 contrast, assets that are taken out of service before 15 years remain on the books  
6 until the amortization period for that vintage has expired.

7 **Q. FOR WHICH PLANT ACCOUNTS IS AMORTIZATION ACCOUNTING**  
8 **BEING IMPLEMENTED?**

9 A. Amortization accounting is only appropriate for certain General Plant accounts.  
10 These accounts are 391.00, 392.00, 393.00, 394.00, 395.00, 396.00, 397.10, 397.21,  
11 397.30, and 398.00 for General Plant which represents slightly less than 4% of  
12 depreciable plant.

13 **Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE THE DEVELOPMENT**  
14 **OF THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A**  
15 **PARTICULAR GROUP OF PROPERTY IN YOUR DEPRECIATION**  
16 **STUDY.**

17 A. I will use Account 353.00, Station Equipment, as an example because it is one of  
18 the largest depreciable groups.

19 The retirement rate method was used to analyze the survivor characteristics  
20 of this property group. Aged plant accounting data were compiled from 1954  
21 through 2024 and analyzed in periods that best represent the overall service life of  
22 this property. The life table for the 1954-2024 experience band is presented in the  
23 Depreciation Study on pages VII-25 and VII-26. The life table displays the

1 retirement and surviving ratios of the aged plant data exposed to retirement by age  
2 interval. For example, page VII-25 of Exhibit JJS-1, shows \$178,275 retired during  
3 age interval 0.5-1.5 with \$336,437,731 exposed to retirement at the beginning of  
4 the interval. Consequently, the retirement ratio is 0.0005 ( $\$178,275 / \$336,437,731$ )  
5 and the survivor ratio is 0.9995 ( $1 - 0.0005$ ). The life table, or original survivor  
6 curve, is plotted along with the estimated smooth survivor curve, the 50-R1.5, on  
7 page VII-24 of Exhibit JJS-1.

8 The net salvage percent is presented on pages VIII-17 and VIII-18. The  
9 percentage is based on the result of annual gross salvage minus the cost to remove  
10 plant assets as compared to the original cost of plant retired during  
11 the period 2000 through 2024. The 25-year period experienced \$6,048,138  
12 ( $\$2,873,596 - \$8,921,734$ ) in net salvage for \$32,986,468 plant retired. The result is  
13 negative net salvage of 18% ( $\$6,048,138 / \$32,986,468$ ). Recent trends (i.e., the  
14 five-year average) have shown indications of negative 42%, therefore, it was  
15 determined that based on industry ranges, historical indications and Company  
16 expectations, that negative 15% was the most appropriate estimate. The negative  
17 15% estimate considers the entire period and does not put as much weight on recent  
18 trends as cost of removal is expected to be lower in the future than the levels over  
19 the last five years for the assets being retired.

20 My calculation of the annual depreciation related to original cost of electric  
21 utility plant as of March 31, 2025, for Account 353.00 is presented on pages IX-29  
22 and IX-30 of Exhibit JJS-1. The calculation is based on the 50-R1.5 survivor curve,  
23 15% negative net salvage, the attained age, and the allocated book reserve. The

1 tabulation sets forth the installation year, the original cost, calculated accrued  
2 depreciation, allocated book reserve, future accruals, remaining life and annual  
3 accrual. These totals are brought forward to Table 1 on page VI-4.

4 **Q. HAVE YOU DEVELOPED RATES FOR FUTURE ASSETS?**

5 A. Yes. There are plans to add new technology Advanced Metering Infrastructure  
6 (“AMI”) Meters for distribution plant. The rates for these assets will be based on  
7 a 20-S1 survivor curve and two percent negative net salvage. The survivor curve  
8 is based on the meters having a 20-year life and the meter infrastructure having a  
9 15-year life. Also, there are plans to add new computer software and hardware  
10 assets. The rates for these assets will be amortized based on a 5-SQ survivor curve.  
11 The rate for all of these assets is presented on page VI-6 of Exhibit JJS-1.

### **III. CONCLUSION**

12 **Q. IN YOUR OPINION, ARE THE DEPRECIATION RATES SET FORTH IN**  
13 **EXHIBIT JJS-1 THE RECOMMENDED RATES FOR THE COMMISSION**  
14 **TO ADOPT IN THIS PROCEEDING FOR KENTUCKY POWER?**

15 A. Yes. These depreciation rates appropriately reflect the rates at which the value of  
16 Kentucky Power’s electric assets are being consumed over their useful lives. These  
17 rates are an appropriate and reasonable basis for setting electric rates in this matter  
18 and for the Company to use for booking depreciation expense going forward.

19 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

20 A. Yes.

## VERIFICATION

The undersigned, John J. Spanos, being duly sworn, deposes and says he is the President of Gannett Fleming Valuation and Rate Consultants, LLC, 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.

John J. Spanos  
John J. Spanos

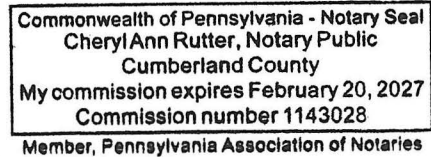
Commonwealth of Pennsylvania )  
 ) Case No. 2025-00257  
County of Cumberland )

Subscribed and sworn to before me, a Notary Public in and before said County  
and Commonwealth, by John J. Spanos, on August 21, 2025.

  
Notary Public

My Commission Expires February 20, 2027

Notary ID Number 1143028







## 2025 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS  
RELATED TO ELECTRIC PLANT  
AS OF MARCH 31, 2025

*Prepared by:*



KENTUCKY POWER COMPANY

Ashland, Kentucky

2025 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS  
RELATED TO ELECTRIC PLANT  
AS OF MARCH 31, 2025

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC  
Mechanicsburg, Pennsylvania

**Gannett Fleming  
Valuation and Rate Consultants, LLC**

300 Sterling Parkway, Suite 200  
Mechanicsburg, PA 17050  
717.763.7211

August 11, 2025

Kentucky Power Company  
1645 Winchester Avenue  
Ashland, KY 41101

Attention Tanner S. Wolfram  
Director Regulatory Services

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant of Kentucky Power Company as of March 31, 2025. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual and accrued depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION  
AND RATE CONSULTANTS, LLC



JOHN J. SPANOS  
President



GLEN A. FRIEL  
Assistant Project Manager

JJS:mle

082510.000

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## KENTUCKY POWER COMPANY

### DEPRECIATION STUDY

#### EXECUTIVE SUMMARY

Pursuant to Kentucky Power Company's ("Kentucky Power Company" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to electric plant as of March 31, 2025. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets.

Kentucky Power Company's accounting policy has not changed since the last depreciation study was prepared. However, there have been changes in plans of some assets as well as additions of capital investment in all plant categories. For transmission plant, the overall depreciation has decreased due mostly to longer service lives and less negative net salvage for most plant accounts. For distribution plant, depreciation has increased overall due to more negative net salvage which was partially offset by longer service lives for most accounts. For generation assets, the probable retirement date for Big Sandy was increased from the last case. Additionally, the survivor curves and weighted net salvage values were updated through 2024.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric plant in service as of March 31, 2025 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of \$141.0 million when applied to depreciable plant balances as of March 31, 2025. The results are summarized at the functional level as follows:

**SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS**

<b>FUNCTION</b>	<b>ORIGINAL COST AS OF MARCH 31, 2025</b>	<b>PROPOSED RATE</b>	<b>PROPOSED EXPENSE</b>
Steam Production Plant	\$ 1,286,622,340.53	4.42	\$56,860,833
Transmission Plant	953,186,764.13	2.48	23,630,852
Distribution Plant	1,207,059,455.14	3.76	45,430,227
General Plant	<u>171,357,863.03</u>	8.81	<u>15,104,613</u>
<b>Total</b>	<b><u>\$3,618,226,422.83</u></b>	<b>3.90</b>	<b><u>\$141,026,525</u></b>

---

## PART I. INTRODUCTION



## **KENTUCKY POWER COMPANY**

### **DEPRECIATION STUDY**

#### **PART I. INTRODUCTION**

##### **SCOPE**

This report sets forth the results of the depreciation study for Kentucky Power Company (“Company”), to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of electric plant as of March 31, 2025. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to electric plant in service as of March 31, 2025.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2024, the net salvage analyses of historical plant retirement data recorded through 2024, a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

##### **PLAN OF REPORT**

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life and net salvage studies. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized

for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

## **BASIS OF THE STUDY**

### **Depreciation**

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. For certain

General Plant accounts, the annual depreciation is based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and net salvage.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been accepted in Kentucky. Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-3 of the report.

### **Service Life and Net Salvage Estimates**

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for electric plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

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## **PART II. ESTIMATION OF SURVIVOR CURVES**

## **PART II. ESTIMATION OF SURVIVOR CURVES**

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below, and the development of net salvage is discussed in later sections of this report.

### **SURVIVOR CURVES**

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

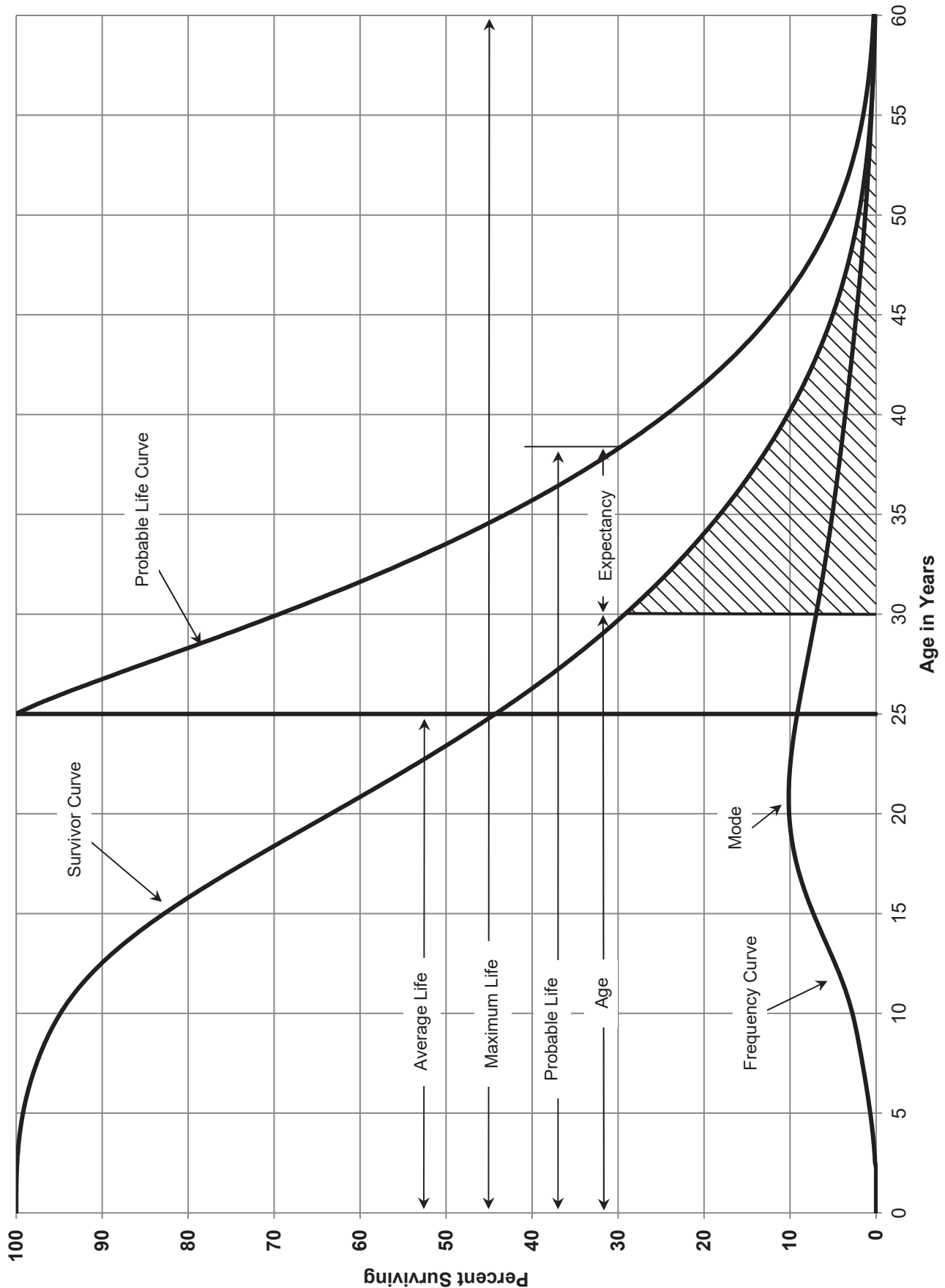
The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

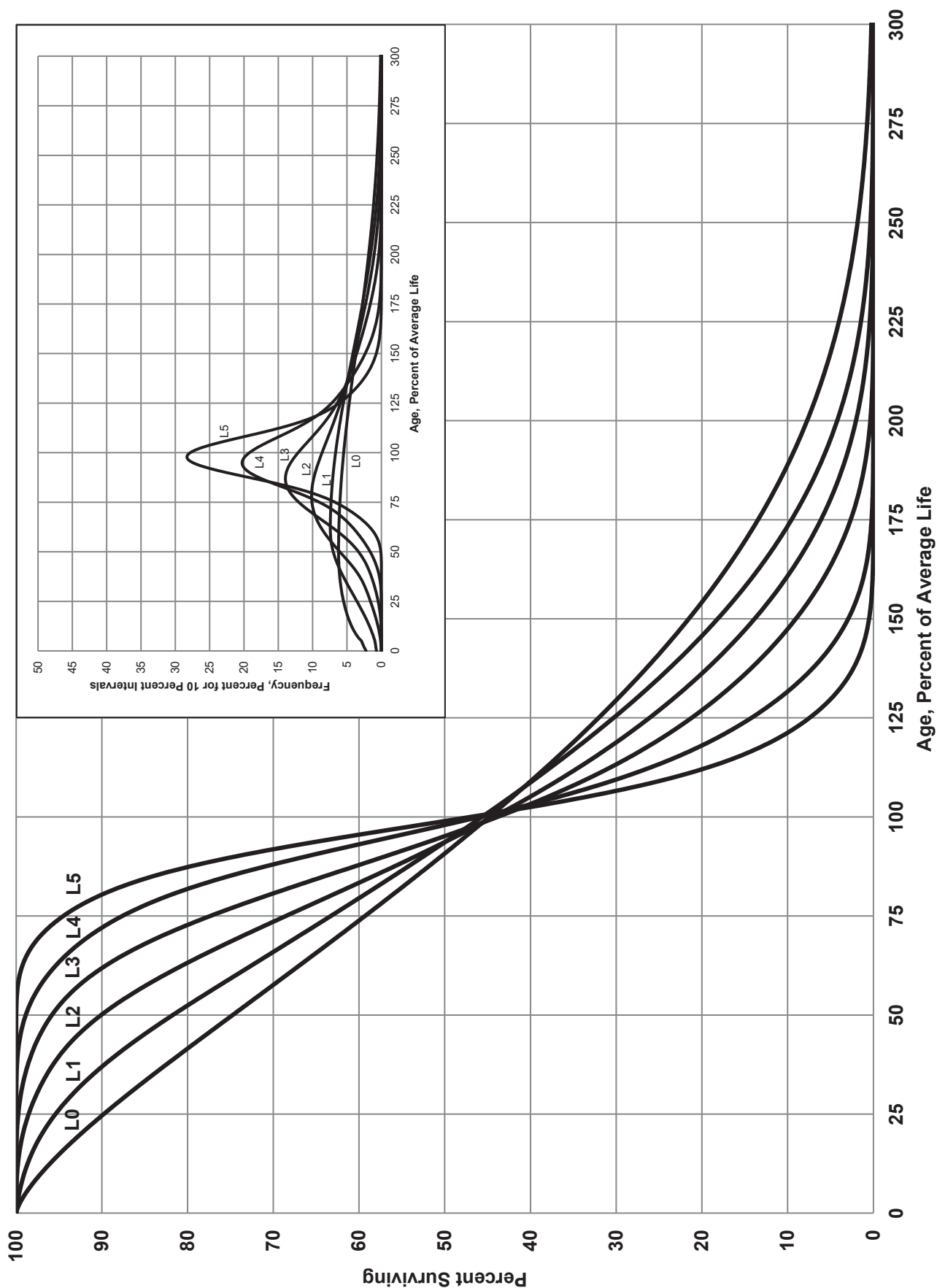
### **Iowa Type Curves**

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

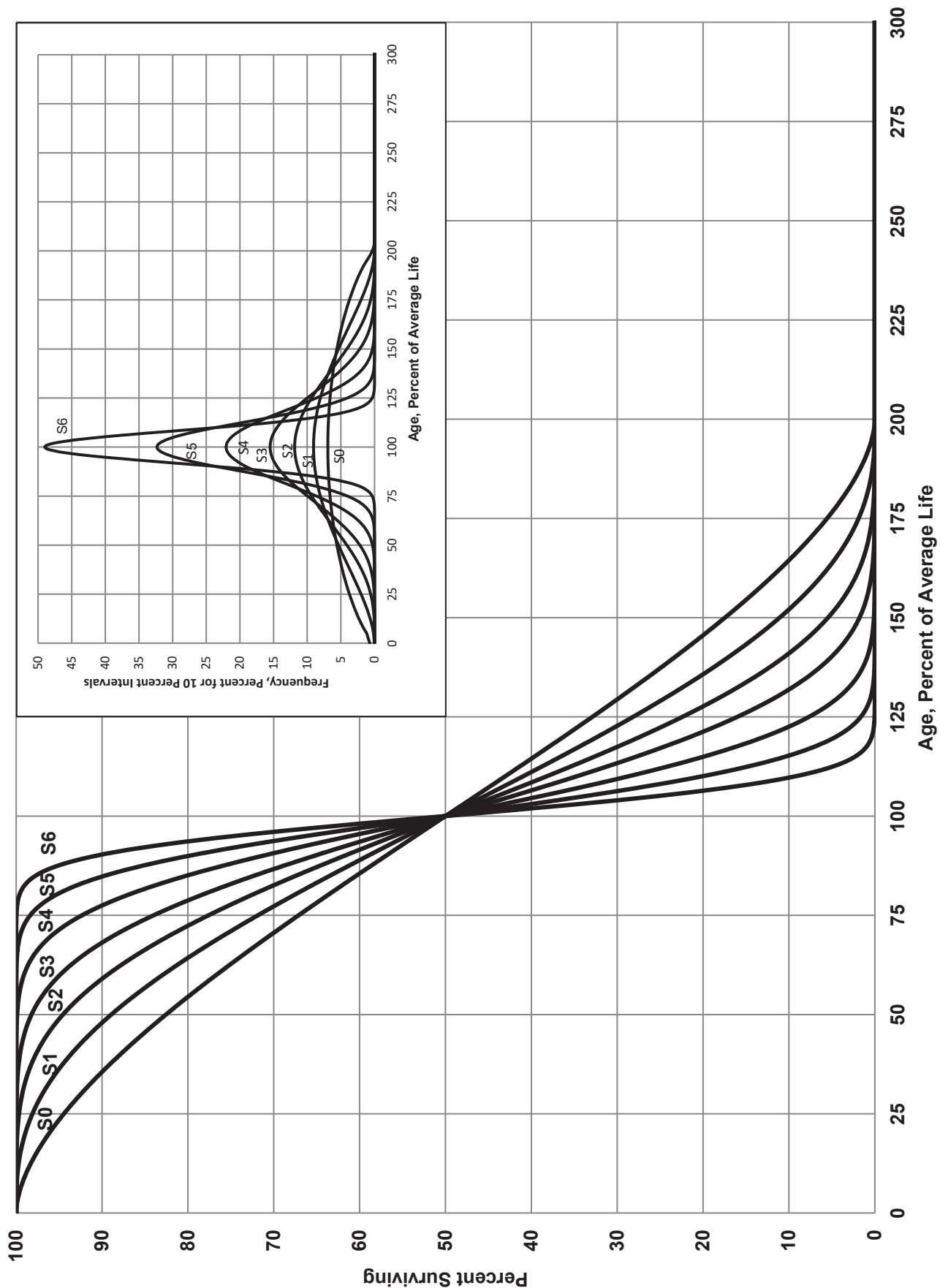


**FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES**

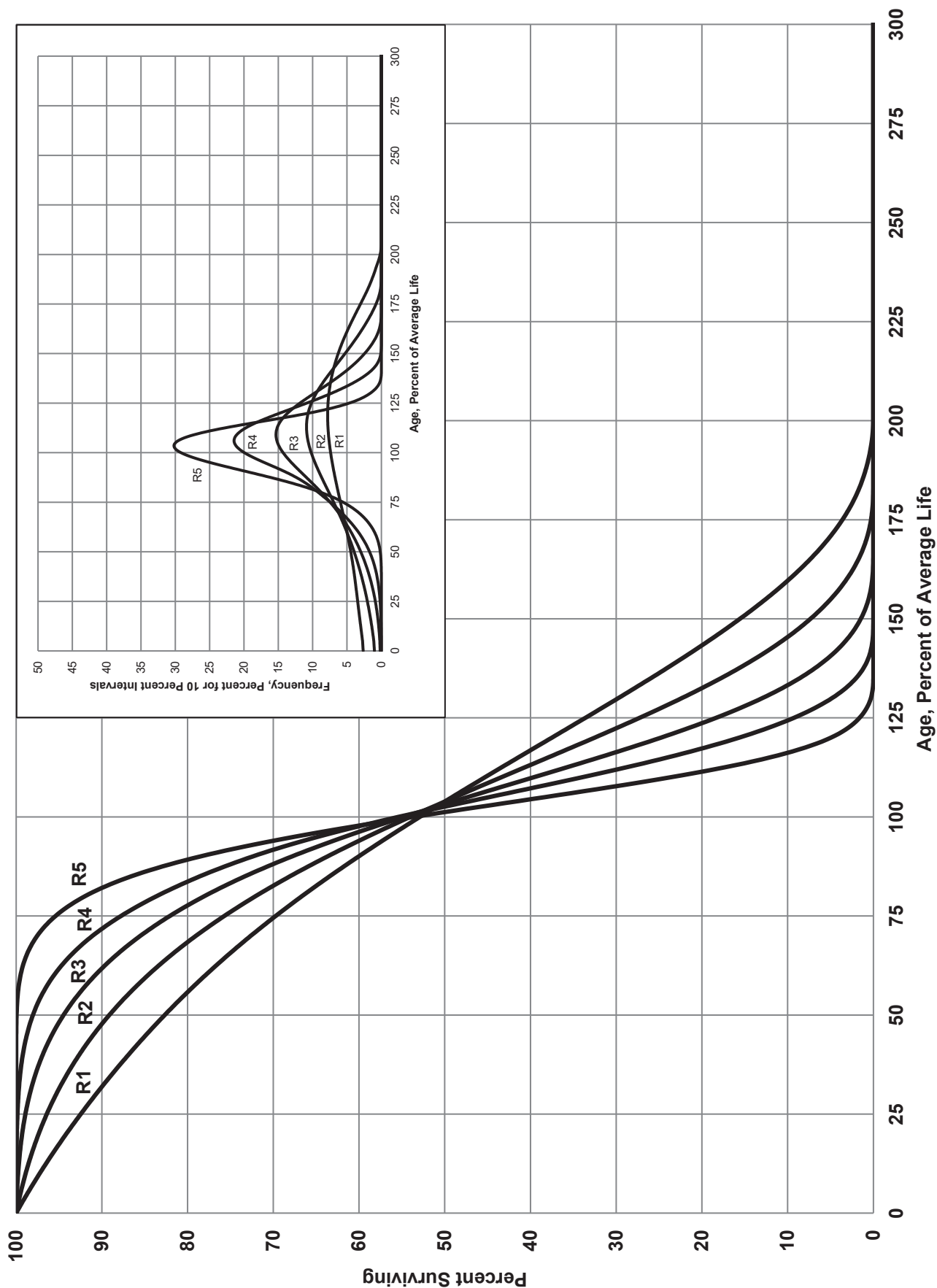


**FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES**





**FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES**



**FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES**

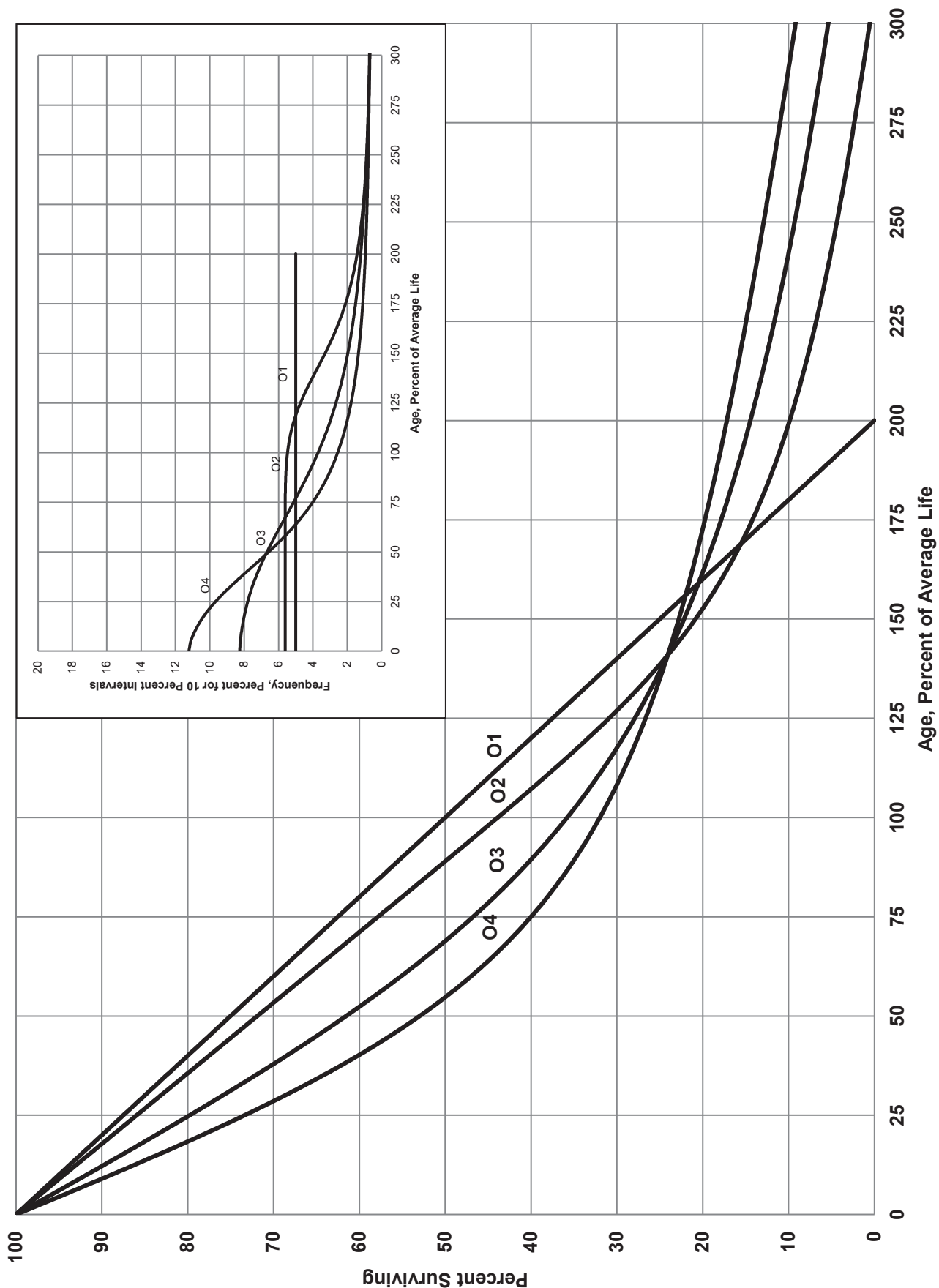


FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."<sup>1</sup> In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

### **Retirement Rate Method of Analysis**

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"<sup>2</sup> "Engineering Valuation and Depreciation,"<sup>3</sup> and "Depreciation Systems."<sup>4</sup>

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

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<sup>1</sup>Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

<sup>2</sup>Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

<sup>3</sup>Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

<sup>4</sup>Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

### **Schedules of Annual Transactions in Plant Records**

The property group used to illustrate the retirement rate method is observed for the experience band 2015-2024 for which there were placements during the years 2010-2024. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, \$10,000 of the dollars invested in 2010 were retired in 2015. The \$10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of \$143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2015 retirements of 2010 installations and ending with the 2024 retirements of the 2019 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

**SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2015-2024  
SUMMARIZED BY AGE INTERVAL**

Experience Band 2015-2024											Placement Band 2010-2024										
Year		Retirements, Thousands of Dollars										Total During		Age							
		During Year																			
		<u>2015</u> (1)	<u>2016</u> (3)	<u>2017</u> (4)	<u>2018</u> (5)	<u>2019</u> (6)	<u>2020</u> (7)	<u>2021</u> (8)	<u>2022</u> (9)	<u>2023</u> (10)	<u>2024</u> (11)										
<u>Placed</u> (2)	<u>2015</u> (2)	<u>2016</u> (3)	<u>2017</u> (4)	<u>2018</u> (5)	<u>2019</u> (6)	<u>2020</u> (7)	<u>2021</u> (8)	<u>2022</u> (9)	<u>2023</u> (10)	<u>2024</u> (11)	<u>Age Interval</u> (12)	<u>Interval</u> (13)									
2010	10	11	12	13	14	16	23	24	25	26	26	13½-14½									
2011	11	12	13	15	16	18	20	21	22	19	19	12½-13½									
2012	11	12	13	14	16	17	19	21	22	18	18	11½-12½									
2013	8	9	10	11	11	13	14	15	16	17	17	10½-11½									
2014	9	10	11	12	13	14	16	17	19	20	20	9½-10½									
2015	4	9	10	11	12	13	14	15	16	20	20	8½-9½									
2016		5	11	12	13	14	15	16	18	20	20	7½-8½									
2017			6	12	13	15	16	17	19	19	19	6½-7½									
2018				6	13	15	16	17	19	19	19	5½-6½									
2019					7	14	16	17	19	20	20	4½-5½									
2020						8	18	20	22	23	23	3½-4½									
2021							9	20	22	25	25	2½-3½									
2022								11	23	25	25	1½-2½									
2023									11	24	24	½-1½									
2024										13	13	0-½									
Total	53	68	86	106	128	157	196	231	273	308	1,606										

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2015-2024  
SUMMARIZED BY AGE INTERVAL

Experience Band 2015-2024				Placement Band 2010-2024									
Acquisitions, Transfers and Sales, Thousands of Dollars													
		During Year										Total During Age Interval (12)	Age Interval (13)
Year Placed (1)	2015 (2)	2016 (3)	2017 (4)	2018 (5)	2019 (6)	2020 (7)	2021 (8)	2022 (9)	2023 (10)	2024 (11)			
2010	-	-	-	-	-	-	60 <sup>a</sup>	-	-	-	-	-	13½-14½
2011	-	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2012	-	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2013	-	-	-	-	-	-	-	(5) <sup>b</sup>	-	-	-	60	10½-11½
2014	-	-	-	-	-	-	-	6 <sup>a</sup>	-	-	-	-	9½-10½
2015	-	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2016	-	-	-	-	-	-	-	-	-	-	-	6	7½-8½
2017	-	-	-	-	-	-	-	-	-	-	-	-	6½-7½
2018	-	-	-	-	-	-	-	(12) <sup>b</sup>	-	-	-	-	5½-6½
2019	-	-	-	-	-	-	-	-	22 <sup>a</sup>	-	-	-	4½-5½
2020	-	-	-	-	-	-	-	(19) <sup>b</sup>	-	-	-	10	3½-4½
2021	-	-	-	-	-	-	-	-	-	-	-	-	2½-3½
2022	-	-	-	-	-	-	-	-	-	(102) <sup>c</sup>	-	(121)	1½-2½
2023	-	-	-	-	-	-	-	-	-	-	-	-	½-1½
2024	-	-	-	-	-	-	-	-	-	-	-	-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	-	(50)	

<sup>a</sup> Transfer Affecting Exposures at Beginning of Year

<sup>b</sup> Transfer Affecting Exposures at End of Year

<sup>c</sup> Sale with Continued Use

Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

### **Schedule of Plant Exposed to Retirement**

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2015 through 2024 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2020 are calculated in the following manner:

Exposures at age 0	= amount of addition	= \$750,000
Exposures at age ½	= \$750,000 - \$ 8,000	= \$742,000
Exposures at age 1½	= \$742,000 - \$18,000	= \$724,000
Exposures at age 2½	= \$724,000 - \$20,000 - \$19,000	= \$685,000
Exposures at age 3½	= \$685,000 - \$22,000	= \$663,000



SCHEDULE 3. PLANT EXPOSED TO RETIREMENT  
JANUARY 1 OF EACH YEAR 2015-2024  
SUMMARIZED BY AGE INTERVAL

Experience Band 2015-2024										Placement Band 2010-2024			
Year Placed	Exposures, Thousands of Dollars										Total at		Age Interval
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Beginning of Age Interval	(12)	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(13)
2010	255	245	234	222	209	195	239	216	192	167	167	167	13½-14½
2011	279	268	256	243	228	212	194	174	153	131	323	323	12½-13½
2012	307	296	284	271	257	241	224	205	184	162	531	531	11½-12½
2013	338	330	321	311	300	289	276	262	242	226	823	823	10½-11½
2014	376	367	357	346	334	321	307	297	280	261	1,097	1,097	9½-10½
2015	420 <sup>a</sup>	416	407	397	386	374	361	347	332	316	1,503	1,503	8½-9½
2016		460 <sup>a</sup>	455	444	432	419	405	390	374	356	1,952	1,952	7½-8½
2017			510 <sup>a</sup>	504	492	479	464	448	431	412	2,463	2,463	6½-7½
2018				580 <sup>a</sup>	574	561	546	530	501	482	3,057	3,057	5½-6½
2019					660 <sup>a</sup>	653	639	623	628	609	3,789	3,789	4½-5½
2020						750 <sup>a</sup>	742	724	685	663	4,332	4,332	3½-4½
2021							850 <sup>a</sup>	841	821	799	4,955	4,955	2½-3½
2022								960 <sup>a</sup>	949	926	5,719	5,719	1½-2½
2023									1,080 <sup>a</sup>	1,069	6,579	6,579	½-1½
2024										1,220 <sup>a</sup>	7,490	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	44,780	

<sup>a</sup>Additions during the year

For the entire experience band 2015-2024, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$$255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.$$

### **Original Life Table**

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15	
Exposures at age 4½	=	3,789,000	
Retirements from age 4½ to 5½	=	143,000	
Retirement Ratio	=	143,000 ÷ 3,789,000	= 0.0377
Survivor Ratio	=	1.000 - 0.0377	= 0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	= 84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE  
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2015-2024

Placement Band 2010-2024

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	<u>167</u>	<u>26</u>	0.1557	0.8443	42.24
					35.66
Total	<u>44,780</u>	<u>1,606</u>			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.

Column 3 from Schedule 1, Column 12, Retirements for Each Year.

Column 4 = Column 3 Divided by Column 2.

Column 5 = 1.0000 Minus Column 4.

Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

### **Smoothing the Original Survivor Curve**

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE  
ORIGINAL AND SMOOTH SURVIVOR CURVES

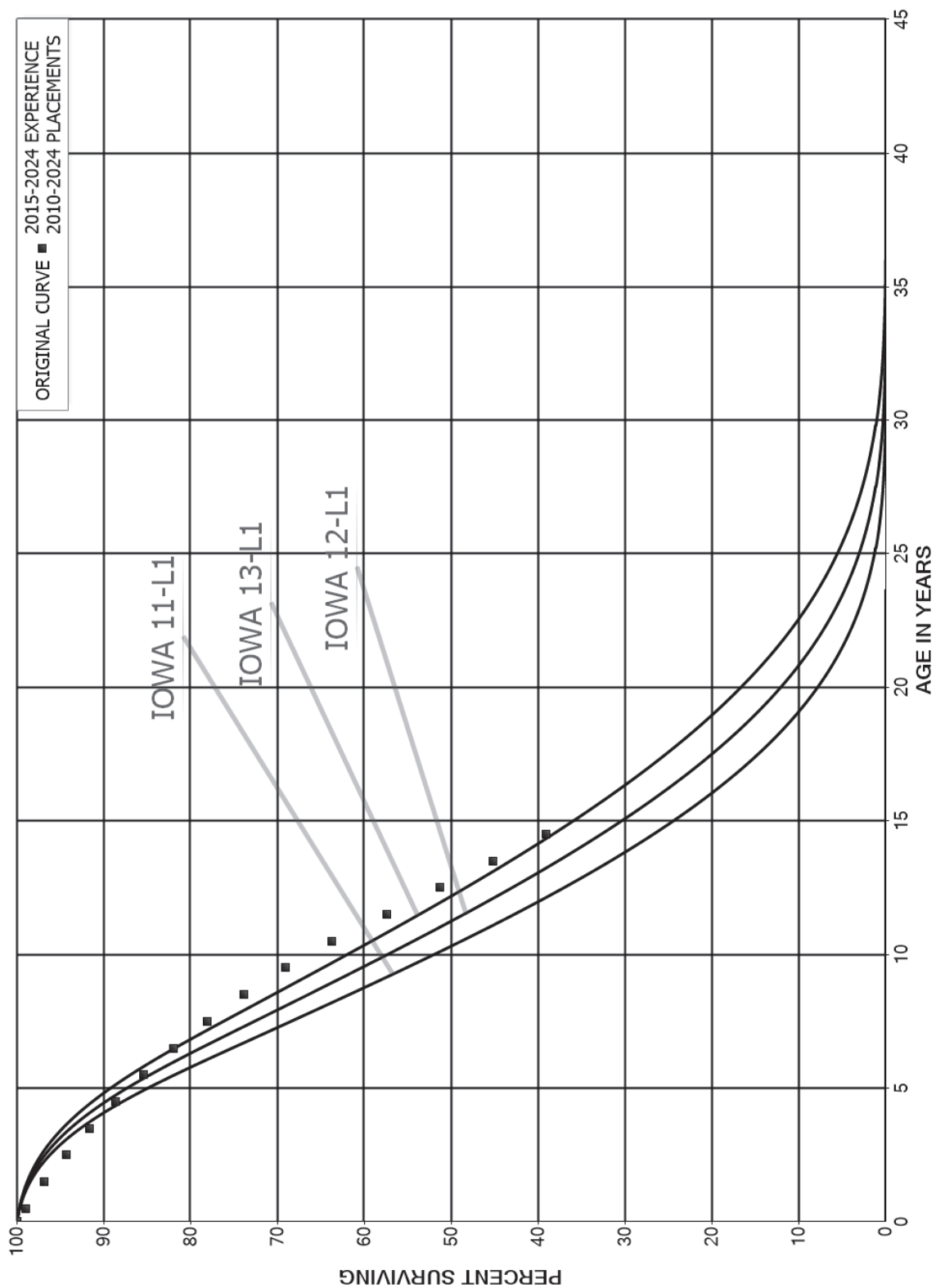


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE  
ORIGINAL AND SMOOTH SURVIVOR CURVES

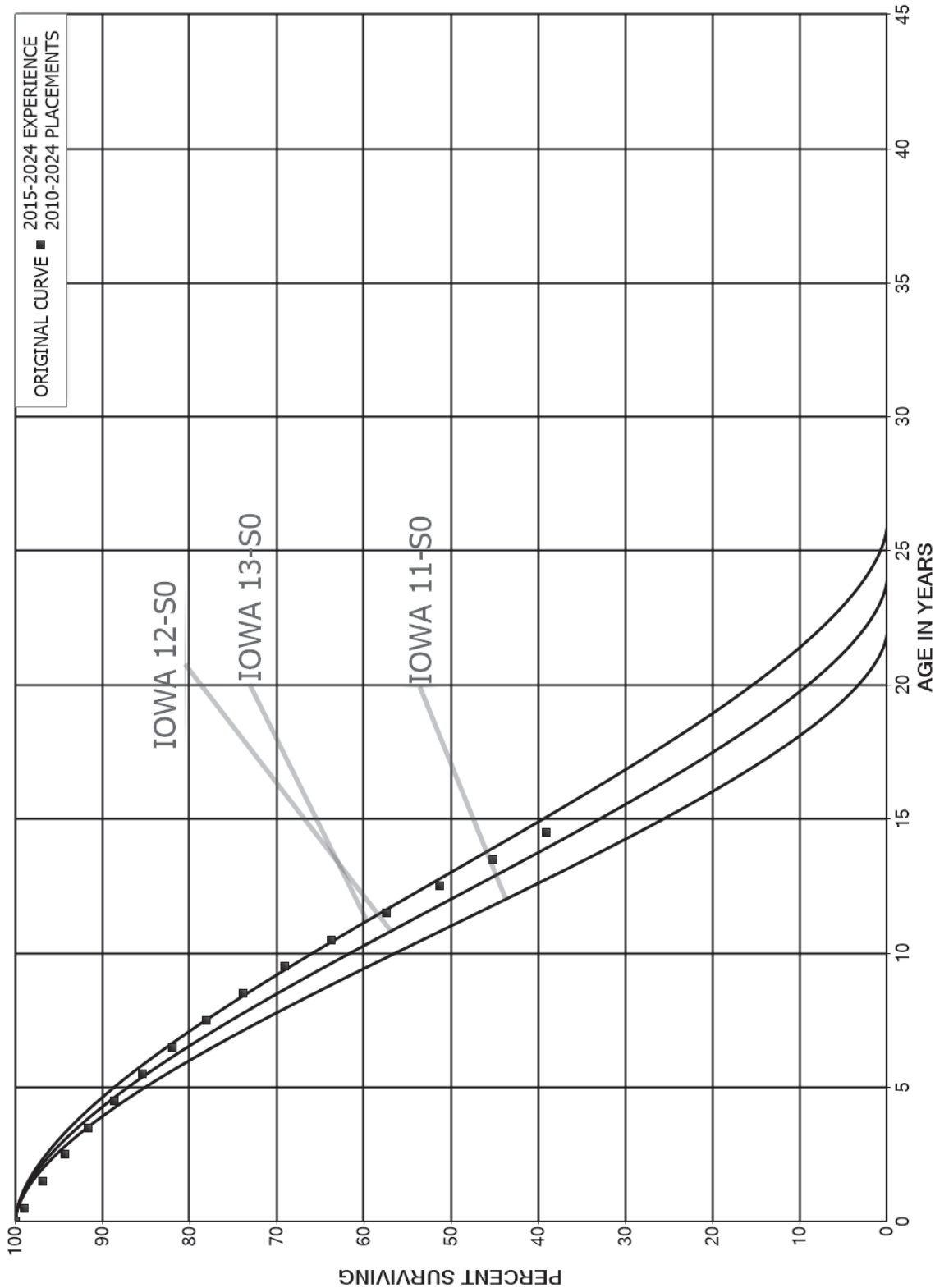


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE  
ORIGINAL AND SMOOTH SURVIVOR CURVES

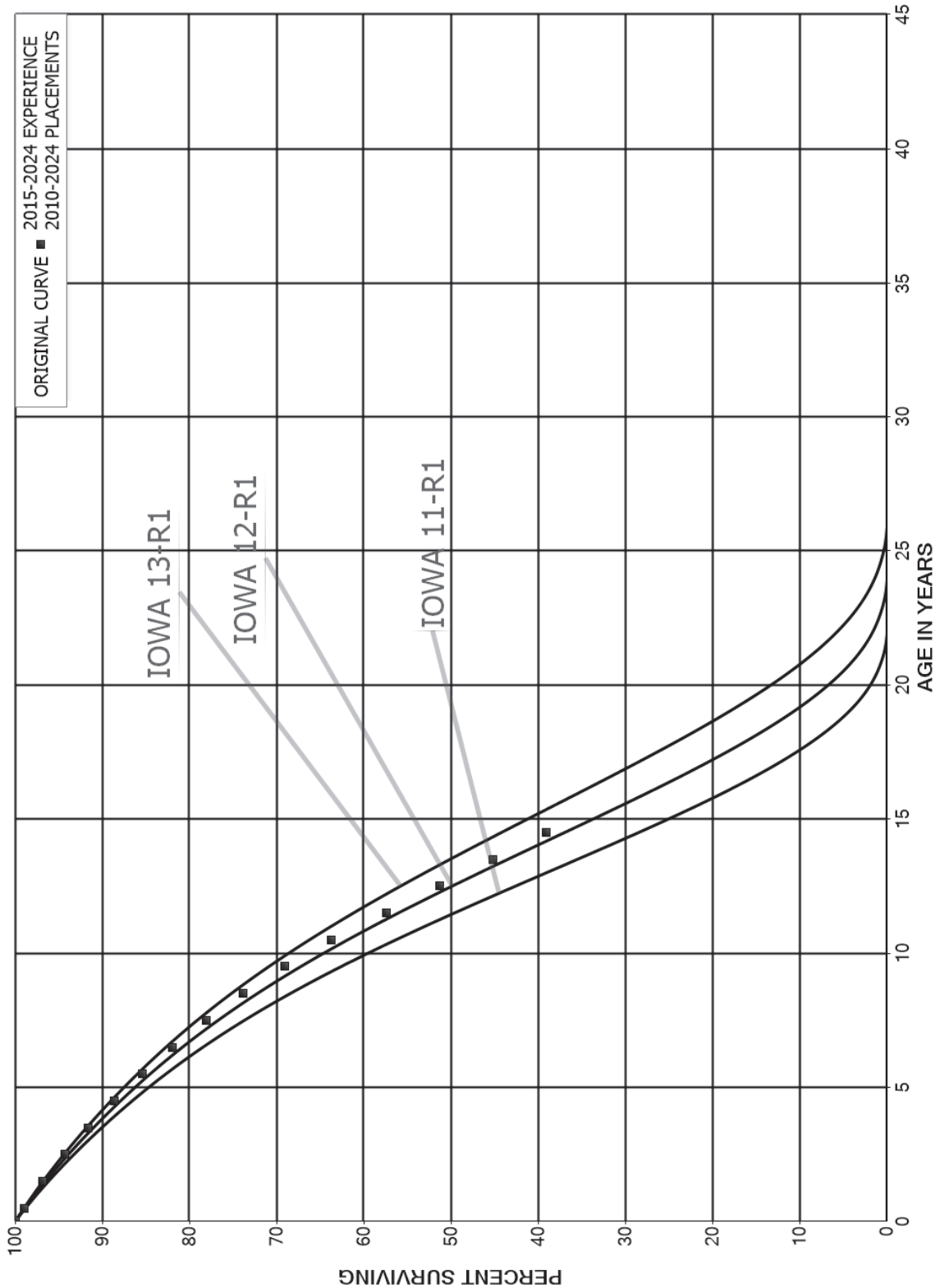
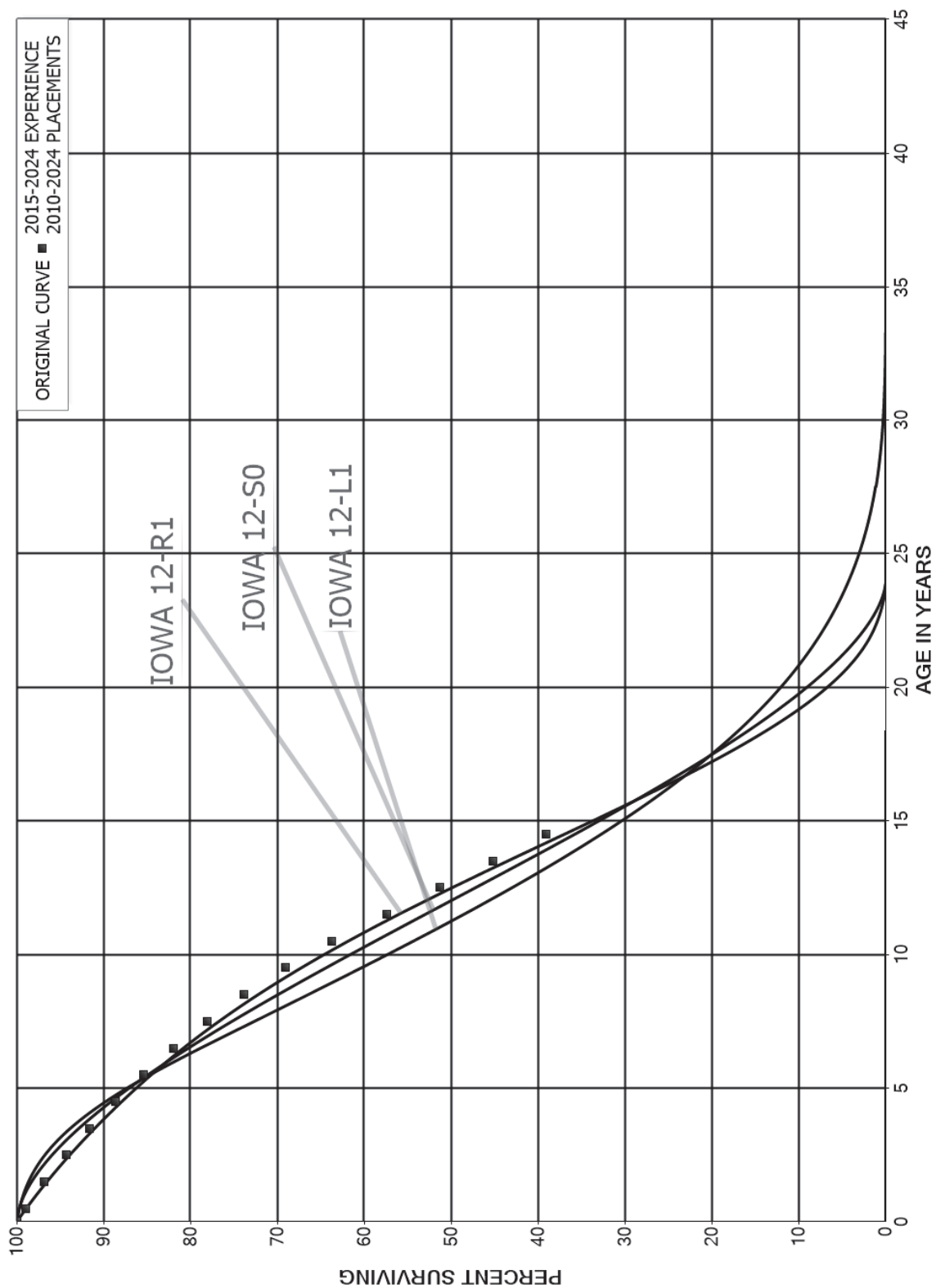


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE  
ORIGINAL AND SMOOTH SURVIVOR CURVES





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## **PART III. SERVICE LIFE CONSIDERATIONS**

## **PART III. SERVICE LIFE CONSIDERATIONS**

### **FIELD TRIPS**

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent field trips.

#### December 18, 2024

- Big Sandy Steam Plant
- Big Sandy Substation
- Calgan Substation
- 47<sup>th</sup> Street Substation
- Princess Substation
- Cannonsburg Service Center

#### February 22, 2023

- Big Sandy Steam Plant
- Baker Substation
- Chadwick Substation
- 10<sup>th</sup> Street Substation
- Bellefonte Substation
- Princess Substation
- Robert E. Matthews Service Center
- Kentucky Power Main Office

### **SERVICE LIFE ANALYSIS**

The service life estimates were based on informed judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric companies.

For many of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 85 percent of depreciable plant. Generally, the information external to the statistics led to little or no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

#### STEAM PRODUCTION PLANT

311.00	Structures and Improvements
312.00	Boiler Plant Equipment
315.00	Accessory Electric Equipment

#### TRANSMISSION PLANT

352.00	Structures and Improvements
353.00	Station Equipment
354.00	Towers and Fixtures
355.00	Poles and Fixtures

#### DISTRIBUTION PLANT

361.00	Structures and Improvements
362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
367.00	Underground Conductors and Devices
368.00	Line Transformers
369.00	Services
370.00	Meters
371.00	Installations on Customers' Premises
373.00	Street Lighting and Signal Systems

#### GENERAL PLANT

390.00	Structures and Improvements
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Account 364.00, Poles, Towers and Fixtures, and Account 365.00, Overhead Conductors and Devices are used to illustrate the manner in which the study was conducted for the groups in the preceding list. Account 364.00 represents 9 percent, and Account 365.00 represents 10 percent of the total depreciable plant. Aged plant accounting data have been compiled for the years 1954 through 2024. These data have

been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate for Account 364.00, Poles, Towers and Fixtures, is the 50-R1.5 and is based on the statistical indication for the period 2009 through 2024. The 50-R1.5 is a good fit of the significant portion of the original survivor curve as set forth on page VII-53 consistent with management outlook for a continuation of historical experience, and is within the typical service life range of 40 to 55 years for distribution poles and fixtures.

The survivor curve estimate for Account 365.00, Overhead Conductors and Devices, is based on the statistical indications for the period 2009 through 2024. The Iowa 42-R1.5 is an excellent fit of the original survivor curve. The 42 year service life is on the lower end of the typical service life range of 40 to 55 years for overhead conductors. The 42-year life reflects the Company's continued practices of steady retirements for all vintages.

The survivor curve estimates for the remaining accounts were based on judgment incorporating the statistical analyses and previous studies for this and other electric utilities.

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric companies.

The selected amortization periods for other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

## **Life Span Estimates**

The life span technique was used for the Company's power production accounts. The life span procedure is appropriate for these accounts since many of the assets within the plant will be retired concurrently. Probable retirement dates were estimated for each generating facility and structure. Life spans for each steam production plant were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel concerning the probable long-term outlook for the units, and the estimate of the operating partner, if applicable.

The depreciable life span estimate for steam, base-load units at Big Sandy is 78 years and at Mitchell is 69 years. The typical range of life spans for such units in the past has been 50 to 65 years. This life span represents the expected depreciable life of the facility under its current configuration. Future capital expenditures can extend a facility's depreciable life, however, such changes to depreciable life would not be prudent until the capital expenditures are actually put into plant in service.

The life span and probable retirement dates used for steam production plants are as follows:

<u>Depreciable Group</u>	<u>Major Year in Service</u>	<u>Depreciable Life Date</u>	<u>Depreciable Life Span</u>
Steam Production Plant			
Big Sandy	1963	2041	78
Mitchell	1971	2040	69

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## **PART IV. NET SALVAGE CONSIDERATIONS**

## **PART IV. NET SALVAGE CONSIDERATIONS**

### **NET SALVAGE ANALYSIS**

The estimates of net salvage by account were based in part on historical data compiled for the years 2000 through 2024. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired. The weighted net salvage analysis for generation assets was updated through March 2025.

#### **Net Salvage Considerations**

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and gross salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and gross salvage data are presented in the section titled “Net Salvage Statistics” for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period 2000 through 2024 by plant account were analyzed. The analyses contributed significantly toward the net salvage estimates for 15 plant accounts, representing 82 percent of the depreciable plant, as follows:

STEAM PRODUCTION PLANT

312.00	Boiler Plant Equipment
314.00	Turbogenerator Units

TRANSMISSION PLANT

353.00	Station Equipment
355.00	Poles and Fixtures
356.00	Overhead Conductors and Devices

DISTRIBUTION PLANT

362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
367.00	Underground Conductors and Devices
368.00	Line Transformers
369.00	Services
370.00	Meters
371.00	Installations on Customers' Premises
373.00	Street Lighting and Signal Systems

GENERAL PLANT

390.00	Structures and Improvements
--------	-----------------------------

Account 365.00, Overhead Conductors and Devices, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 2000 through 2024 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 2000-2002 through 2022-2024 periods were computed to smooth the annual amounts.

Cost of removal has fluctuated over the entire period, however, the past few years have been relatively consistent primarily between 50 and 90 percent. The removal cost is related to the effort needed to remove and safely dispose of overhead conductor. Cost of removal for the most recent five years averaged 70 percent.



Gross salvage has diminished over the last 10 years. The most recent five-year average of 7 percent gross salvage reflects recent trends of minimal salvage value for conductor.

The net salvage percent based on the overall period 2000 through 2024 is 18 percent negative net salvage. The most common range of estimates made by other electric companies for overhead conductor is negative 20 to negative 50 percent. The net salvage estimate for overhead conductor is negative 30 percent, is within the range of estimates for other electric companies, reflects the trend to higher cost of removal and reflects the overall experience for negative net salvage, but does not consider all of the higher cost of removal amounts to be common.

The overall net salvage estimates for the Company's production facilities, for which the life span method is used, is based on estimates of both final net salvage and interim net salvage. Final net salvage is the net salvage experienced at the end of a production plant's life span. Interim net salvage is the net salvage experienced for interim retirements that occur prior to the final retirement of the plant. The final net salvage estimates in the study were based on decommissioning analyses performed by various engineering organizations. The interim net salvage estimates were based in part on analysis of historical interim retirement and net salvage data.

The interim survivor curve estimates for each account and production facility were used to calculate the percentage of plant expected to be retired as interim retirements and terminal retirements. These percentages were used to determine the weighted net salvage estimate for each account and production facility based on the interim and terminal net salvage estimates. These calculations, as well as the estimated terminal net salvage amounts and interim net salvage percents, are shown on Table 2 of the Net Salvage Statistics section on pages VIII-2.

The net salvage percents for the remaining accounts were based on judgment incorporating estimates of previous studies of this and other electric utilities.

Generally, the net salvage estimates for the general plant accounts were zero percent, consistent with amortization accounting.

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## **PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION**

## **PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION**

### **GROUP DEPRECIATION PROCEDURES**

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

#### **Single Unit of Property**

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a \$1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1,000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1,000 \left( 1 - \frac{6}{10} \right) = \$400.$$

#### **Remaining Life Annual Accruals**

For the purpose of calculating remaining life accruals as of March 31, 2025, the depreciation reserve for each plant account is allocated among vintages in proportion to

the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of March 31, 2025, are set forth in the Results of Study section of the report.

### **Average Service Life Procedure**

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals, if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

### **CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION**

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

<u>Account</u>		<u>Amortization Period, Years</u>
<b>ELECTRIC PLANT</b>		
391.00	Office Furniture and Equipment	20
392.00	Transportation Equipment	15
393.00	Stores Equipment	25
394.00	Tools, Shop and Garage Equipment	25
395.00	Laboratory Equipment	20
396.00	Power Operated Equipment	17
397.10	Communication Equipment – Computer Hardware	5
397.21	Communication Equipment – Computer Software	
	5 Year	5
	10 Year	10
	11 Year	11
	15 Year	15
397.30	Communication Equipment	15
398.00	Miscellaneous Equipment	20

For the purpose of calculating annual amortization amounts as of March 31, 2025, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The

annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

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## PART VI. RESULTS OF STUDY



## **PART VI. RESULTS OF STUDY**

### **QUALIFICATION OF RESULTS**

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and net salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric plant in service as of March 31, 2025. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to March 31, 2025, is reasonable for a period of three to five years.

### **DESCRIPTION OF DETAILED TABULATIONS**

Table 1 sets forth a summary of the results of the study as applied to the original cost of electric plant as of March 31, 2025. These results are presented on pages VI-4 and VI-5 of this report. The schedule sets forth the original cost, the book depreciation reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant.

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on page VII-2, within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which were plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The analyses of net salvage data are presented in the section titled, "Net Salvage Statistics." The tabulations present annual cost of removal and gross salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

The tables of the calculated annual depreciation applicable to depreciable assets as of March 31, 2025 are presented in account sequence starting on page IX-2 of the supporting documents. The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life, and the calculated annual accrual amount.

KENTUCKY POWER COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE  
AND CALCULATED ANNUAL DEPRECIATION RATES RELATED TO ELECTRIC PLANT AS OF MARCH 31, 2025

ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF MARCH 31, 2025 (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	ACCUMULATED AMOUNT (8)	ANNUAL RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
<b>ELECTRIC PLANT</b>									
<b>STEAM PRODUCTION PLANT</b>									
<b>BIG SANDY</b>									
311.00	05-2041	70-R2 *	(11)	24,670,707.21	8,314,769	19,069,716	1,219,855	4.94	15.6
312.00	05-2041	60-R0.5 *	(11)	86,987,638.80	34,787,691	61,768,588	4,069,728	4.68	15.2
314.00	05-2041	60-R1 *	(11)	64,460,898.20	37,164,429	34,387,168	2,280,331	3.54	15.1
315.00	05-2041	55-R1.5 *	(11)	8,433,603.87	2,568,085	6,793,216	458,112	5.43	14.8
315.10		5-SQ	0	15,590.07	647	14,943	3,516	22.55	4.2
315.31		15-SQ	0	54,044.17	10,895	43,149	9,15	8.7	8.7
316.00	05-2041	60-R2.5 *	(11)	4,412,888.67	1,922,960	2,975,346	196,530	4.45	15.1
<b>TOTAL BIG SANDY</b>				<b>189,035,370.99</b>	<b>84,769,475</b>	<b>123,062,126</b>	<b>8,233,015</b>	<b>4.36</b>	
<b>MITCHELL</b>									
311.00	12-2040	70-R2 *	(15)	81,292,873.90	29,703,688	63,783,117	4,167,676	5.13	15.3
312.00	12-2040	60-R0.5 *	(15)	916,368,208.97	461,809,228	592,014,212	40,329,581	4.40	14.7
314.00	12-2040	60-R1 *	(15)	61,818,458.05	35,621,017	35,470,210	2,448,834	3.96	14.5
315.00	12-2040	55-R1.5 *	(15)	27,031,759.60	14,744,354	16,342,169	1,150,324	4.26	14.2
315.10		5-SQ	0	25,727.97	3,251	22,477	77.61	77.61	1.1
315.31		15-SQ	0	83,415.21	39,596	43,819	32,298	38.72	1.4
316.00	12-2040	60-R2.5 *	(15)	10,966,525.84	5,415,885	7,195,620	479,138	4.37	15.0
<b>TOTAL MITCHELL</b>				<b>1,097,566,969.54</b>	<b>547,337,019</b>	<b>714,871,624</b>	<b>48,627,818</b>	<b>4.43</b>	
<b>TOTAL STEAM PRODUCTION PLANT</b>				<b>1,286,622,340.53</b>	<b>632,106,495</b>	<b>839,923,750</b>	<b>58,860,833</b>	<b>4.42</b>	
<b>TRANSMISSION PLANT</b>									
350.10		75-R4	0	40,033,509.04	11,706,275	28,327,234	572,191	1.43	49.5
351.20		5-SQ	0	1,364,257.18	4,361	1,359,896	313,024	22.94	4.3
351.30		15-SQ	0	252,866.50	30,315	222,552	17,746	7.02	12.5
352.00		55-S2	(15)	30,153,691.03	2,974,408	31,702,337	701,263	2.33	45.2
353.00		50-R1.5	(15)	313,606,758.83	60,439,882	300,207,891	8,135,436	2.59	36.9
354.00		70-R4	(40)	124,237,593.91	69,391,507	104,541,124	2,526,988	2.03	41.4
355.00		45-R3	(40)	248,149,516.92	67,343,691	280,065,633	7,573,500	3.05	37.0
356.00		65-R3	(40)	188,513,388.69	97,893,109	166,025,635	3,638,487	1.93	45.6
357.00		45-S3	0	6,263,547.27	424,594	5,838,953	138,042	2.20	42.3
358.00		45-R3	0	611,634.76	118,803	492,832	14,155	2.31	34.8
<b>TOTAL TRANSMISSION PLANT</b>				<b>953,186,764.13</b>	<b>310,326,945</b>	<b>918,784,087</b>	<b>23,630,852</b>	<b>2.48</b>	
<b>DISTRIBUTION PLANT</b>									
360.10		75-R4	0	6,524,482.24	3,498,117	3,026,365	53,560	0.82	56.5
361.00		65-R2.5	(20)	19,622,951.04	3,610,978	19,936,563	341,383	1.74	58.4
362.00		38-R1	(15)	170,699,435.29	43,034,050	153,270,301	5,186,318	3.04	29.6
363.20		5-SQ	0	139,902.88	2,266	137,637	28,204	20.16	4.9
363.30		15-SQ	0	1,534,744.77	1,855	1,532,890	103,393	6.74	14.8
363.36		15-SQ	0	1,625,874.64	761,037	864,838	172,820	10.63	5.0
364.00		50-R1.5	(60)	331,435,875.47	122,005,680	408,291,721	10,589,770	3.20	38.6
365.00		42-R1.5	(30)	346,840,093.04	96,131,519	358,760,602	11,265,780	3.25	31.5
366.00		65-R3	(30)	10,181,684.27	4,044,696	9,191,494	178,920	1.76	51.4
367.00		50-R1.5	(20)	13,455,307.69	5,391,594	10,754,775	286,601	2.13	37.5
368.00		35-R2	(60)	173,200,404.54	54,086,447	153,754,038	7,258,123	4.19	21.2
369.00		39-S2.5	(60)	79,697,766.24	33,352,033	94,164,393	3,960,275	4.97	23.8
370.00	12-2029	26-R0.5	(10)	25,671,091.44	12,513,478	15,724,723	3,536,617	4.4	4.4
371.00		12-L0	(20)	20,715,486.95	5,418,281	19,440,303	2,178,604	10.52	8.9
373.00		32-S0	(30)	5,714,354.64	1,142,797	6,285,864	289,859	5.07	21.7
<b>TOTAL DISTRIBUTION PLANT</b>				<b>1,207,069,455.14</b>	<b>384,994,828</b>	<b>1,251,136,507</b>	<b>45,430,227</b>	<b>3.76</b>	

KENTUCKY POWER COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE  
AND CALCULATED ANNUAL DEPRECIATION RATES RELATED TO ELECTRIC PLANT AS OF MARCH 31, 2025

ACCOUNT (1)	PROBABLE RETIREMENT DATE (2)	SURVIVOR CURVE (3)	NET SALVAGE PERCENT (4)	ORIGINAL COST AS OF MARCH 31, 2025 (5)	BOOK DEPRECIATION RESERVE (6)	FUTURE ACCRUALS (7)	ACCUMULATED AMOUNT (8)	CALCULATED ANNUAL ACCUMULATED RATE (9)=(8)/(5)	COMPOSITE REMAINING LIFE (10)=(7)/(8)
<b>GENERAL PLANT</b>									
389.10	LAND RIGHTS	75-R4	0	35,748.12	12,576	23,172	587	1.64	39.5
390.00	STRUCTURES AND IMPROVEMENTS	50-R2	(10)	28,738,308.34	14,909,444	16,702,695	514,281	1.79	32.5
391.00	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	2,518,121.20	939,447	1,578,674	160,932	6.39	9.8
392.00	TRANSPORTATION EQUIPMENT	15-SQ	0	24,068,505.65	2,927,356	21,141,150	1,708,408	7.10	12.4
393.00	STORES EQUIPMENT	25-SQ	0	464,418.36	123,157	341,261	21,155	4.56	16.1
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	20-SQ	0	8,347,272.39	3,157,129	5,190,143	384,709	4.61	13.5
395.00	LABORATORY EQUIPMENT	20-SQ	0	256,820.06	115,132	141,688	11,688	4.54	12.1
396.00	POWER OPERATED EQUIPMENT	17-SQ	0	2,221,244.69	288,513	1,932,732	133,206	6.00	14.5
397.10	COMMUNICATION EQUIPMENT - COMPUTER HARDWARE	5-SQ	0	1,378,530.07	169,563	1,208,967	475,894	34.52	2.5
397.21	COMMUNICATION EQUIPMENT - COMPUTER SOFTWARE	5-SQ	0	43,841,795.17	26,449,753	17,392,042	7,155,120	16.32	2.4
	5 YEAR	10-SQ	0	4,553,052.70	3,528,616	1,024,436	455,305	10.00	2.2
	11 YEAR	11-SQ	0	471,934.55	53,427	418,508	45,244	9.59	9.3
	15 YEAR	15-SQ	0	7,038,488.25	2,464,338	4,574,151	494,503	7.03	9.2
	TOTAL COMMUNICATION EQUIPMENT - COMPUTER SOFTWARE			55,905,270.67	32,496,134	23,409,137	8,150,172	14.58	
397.30	COMMUNICATION EQUIPMENT	15-SQ	0	45,255,752.18	10,662,094	34,593,658	3,448,470	7.62	10.0
398.00	MISCELLANEOUS EQUIPMENT	20-SQ	0	2,167,871.30	1,094,904	1,072,967	95,131	4.39	11.3
	TOTAL GENERAL PLANT			171,357,863.03	66,895,449	107,336,244	15,104,613	8.81	
	TOTAL DEPRECIABLE PLANT			3,618,226,422.83	1,394,323,716	3,117,180,588	141,026,525	3.90	
<b>NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED</b>									
302.00	FRANCHISES AND CONSENTS			52,919.18	52,919				
310.00	LAND			4,980,690.30					
310.10	LAND RIGHTS			5,420.00					
317.00	ARO STEAM PRODUCTION PLANT			34,041,525.87	8,655,867				
350.00	LAND			6,071,983.62	(921)				
360.00	LAND			5,657,796.53					
389.00	LAND			2,098,942.65	11,845				
389.19	ARO GENERAL PLANT			158,819.18	109,950				
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED			53,068,097.33	8,829,860				
	TOTAL ELECTRIC PLANT			3,671,294,520.16	1,403,153,377				

\* LIFE SPAN PROCEDURE USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE.

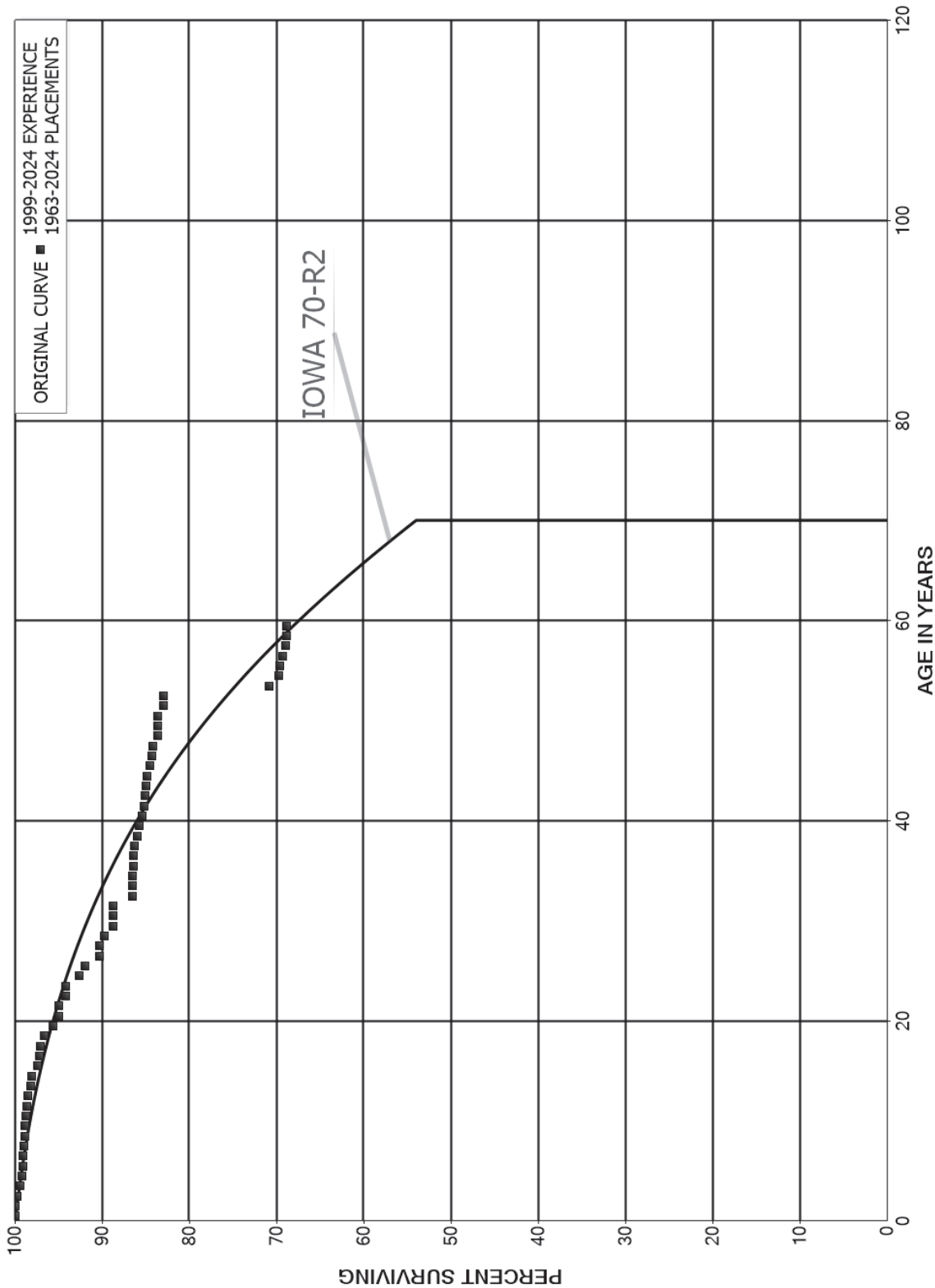
NOTE: NEW ADDITIONS FOR AMI METERS WILL HAVE A DEPRECIATION RATE OF 5.20% BASED ON A SURVIVOR CURVE OF 20-S1 AND NET SALVAGE OF (2) PERCENT. NEW SOFTWARE AND HARDWARE ACCOUNTS WILL HAVE DEPRECIATION RATES AS LISTED BELOW:

ACCOUNT	DESCRIPTION	SURVIVOR CURVE	ACCUMULATED RATE
315.20	ACCESSORY ELECTRIC EQUIPMENT - COMPUTER SOFTWARE	5-SQ	20.00
351.10	COMPUTER HARDWARE	5-SQ	20.00
363.10	COMPUTER HARDWARE	5-SQ	20.00

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## **PART VII. SERVICE LIFE STATISTICS**

KENTUCKY POWER COMPANY  
ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2024

EXPERIENCE BAND 1999-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	71,891,861		0.0000	1.0000	100.00
0.5	51,118,696	41,903	0.0008	0.9992	100.00
1.5	52,157,538	124,012	0.0024	0.9976	99.92
2.5	52,253,057	121,090	0.0023	0.9977	99.68
3.5	52,146,250	142,066	0.0027	0.9973	99.45
4.5	45,847,633	31,195	0.0007	0.9993	99.18
5.5	49,891,270	46,598	0.0009	0.9991	99.11
6.5	45,850,008	38,916	0.0008	0.9992	99.02
7.5	55,699,069	28,025	0.0005	0.9995	98.93
8.5	52,148,441	18,300	0.0004	0.9996	98.88
9.5	49,171,479	78,199	0.0016	0.9984	98.85
10.5	38,460,505	27,123	0.0007	0.9993	98.69
11.5	37,442,238	60,044	0.0016	0.9984	98.62
12.5	36,838,247	112,346	0.0030	0.9970	98.46
13.5	30,412,438	45,151	0.0015	0.9985	98.16
14.5	29,698,127	205,578	0.0069	0.9931	98.02
15.5	24,898,893	36,511	0.0015	0.9985	97.34
16.5	23,873,787	36,345	0.0015	0.9985	97.20
17.5	9,349,074	39,560	0.0042	0.9958	97.05
18.5	8,446,219	88,015	0.0104	0.9896	96.64
19.5	8,014,937	55,793	0.0070	0.9930	95.63
20.5	7,591,504	3	0.0000	1.0000	94.97
21.5	6,621,570	56,944	0.0086	0.9914	94.97
22.5	5,656,053		0.0000	1.0000	94.15
23.5	5,571,192	89,641	0.0161	0.9839	94.15
24.5	5,155,184	38,469	0.0075	0.9925	92.63
25.5	4,848,988	89,772	0.0185	0.9815	91.94
26.5	4,544,672		0.0000	1.0000	90.24
27.5	4,181,034	24,613	0.0059	0.9941	90.24
28.5	5,646,336	59,508	0.0105	0.9895	89.71
29.5	20,540,092	3,748	0.0002	0.9998	88.76
30.5	20,372,591	12,769	0.0006	0.9994	88.75
31.5	20,252,658	509,199	0.0251	0.9749	88.69
32.5	19,775,740	1,167	0.0001	0.9999	86.46
33.5	19,215,056	1	0.0000	1.0000	86.46
34.5	18,572,896	19,905	0.0011	0.9989	86.46
35.5	24,254,462	4,642	0.0002	0.9998	86.37
36.5	25,964,812	34,578	0.0013	0.9987	86.35
37.5	25,690,348	74,660	0.0029	0.9971	86.23
38.5	24,783,769	79,450	0.0032	0.9968	85.98

KENTUCKY POWER COMPANY

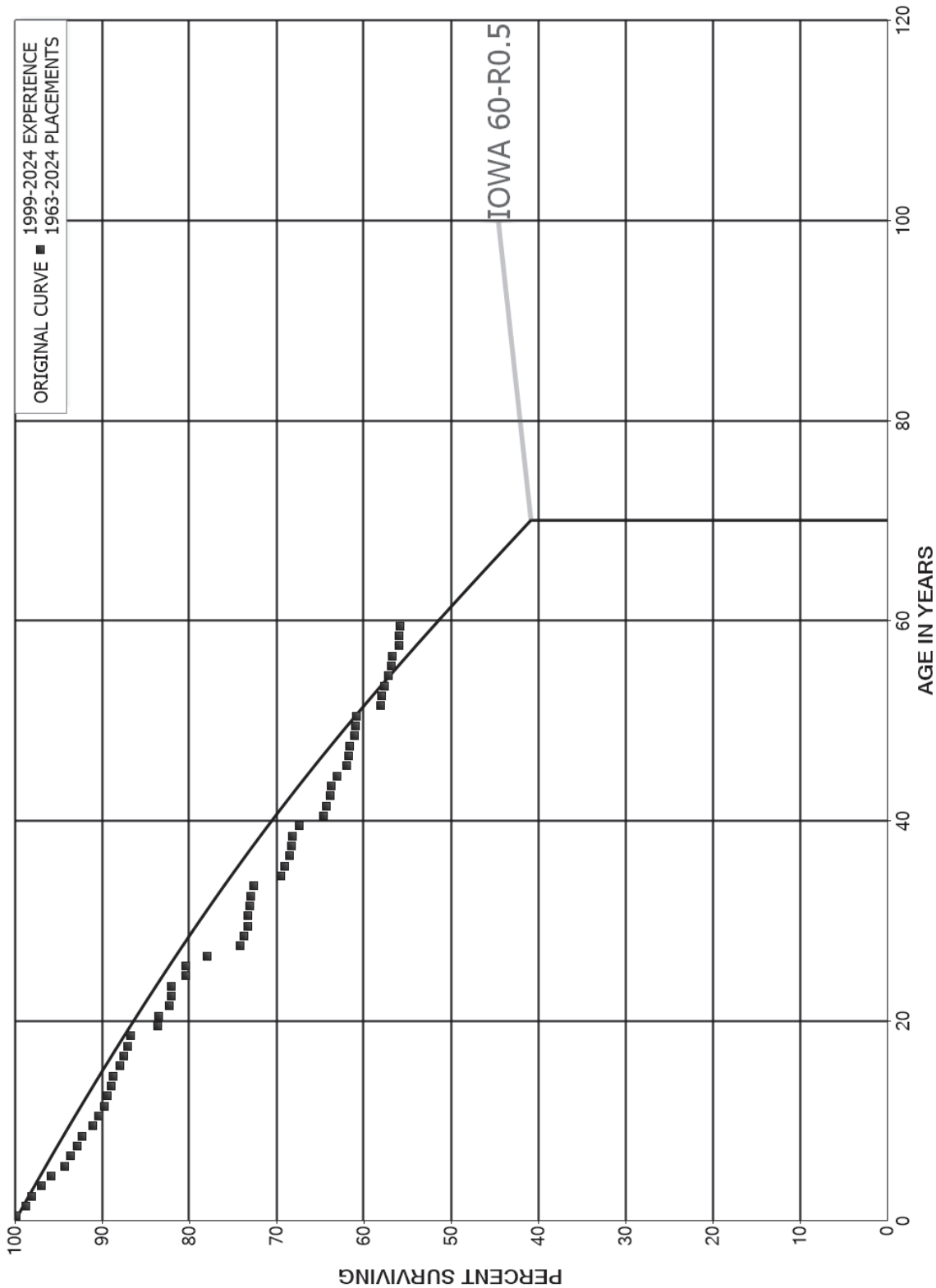
ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2024			EXPERIENCE BAND 1999-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	24,622,799	75,164	0.0031	0.9969	85.71
40.5	24,588,219	89,043	0.0036	0.9964	85.45
41.5	24,493,579	35,948	0.0015	0.9985	85.14
42.5	24,671,242	27,603	0.0011	0.9989	85.01
43.5	34,412,904	33,839	0.0010	0.9990	84.92
44.5	34,215,075	122,589	0.0036	0.9964	84.83
45.5	33,219,343	88,365	0.0027	0.9973	84.53
46.5	16,351,985	20,173	0.0012	0.9988	84.30
47.5	16,295,001	107,039	0.0066	0.9934	84.20
48.5	16,138,087	11,200	0.0007	0.9993	83.65
49.5	16,075,303	1	0.0000	1.0000	83.59
50.5	15,970,433	123,388	0.0077	0.9923	83.59
51.5	15,280,470		0.0000	1.0000	82.94
52.5	13,163,577	1,926,754	0.1464	0.8536	82.94
53.5	3,164,428	46,765	0.0148	0.9852	70.80
54.5	2,986,274	5,772	0.0019	0.9981	69.76
55.5	2,980,503	16,219	0.0054	0.9946	69.62
56.5	2,953,316	14,502	0.0049	0.9951	69.24
57.5	2,938,661	785	0.0003	0.9997	68.90
58.5	2,935,308		0.0000	1.0000	68.88
59.5	2,922,352	2,374	0.0008	0.9992	68.88
60.5	2,910,663	16,384	0.0056	0.9944	68.83
61.5					68.44



KENTUCKY POWER COMPANY  
ACCOUNT 312.00 BOILER PLANT EQUIPMENT  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2024

EXPERIENCE BAND 1999-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	536,526,540	614,031	0.0011	0.9989	100.00
0.5	532,967,039	6,007,881	0.0113	0.9887	99.89
1.5	543,468,234	3,823,011	0.0070	0.9930	98.76
2.5	549,511,491	6,176,931	0.0112	0.9888	98.06
3.5	547,357,736	6,151,014	0.0112	0.9888	96.96
4.5	554,493,373	8,881,467	0.0160	0.9840	95.87
5.5	536,688,611	4,171,794	0.0078	0.9922	94.34
6.5	551,558,736	4,839,800	0.0088	0.9912	93.60
7.5	1,029,772,378	5,227,278	0.0051	0.9949	92.78
8.5	974,946,250	13,291,373	0.0136	0.9864	92.31
9.5	956,017,275	6,605,888	0.0069	0.9931	91.05
10.5	861,158,780	7,099,272	0.0082	0.9918	90.42
11.5	837,419,838	2,412,912	0.0029	0.9971	89.68
12.5	683,728,551	3,746,542	0.0055	0.9945	89.42
13.5	651,545,868	1,483,202	0.0023	0.9977	88.93
14.5	650,482,274	5,674,202	0.0087	0.9913	88.73
15.5	631,209,061	3,441,182	0.0055	0.9945	87.95
16.5	608,819,074	2,605,552	0.0043	0.9957	87.47
17.5	111,128,645	485,868	0.0044	0.9956	87.10
18.5	91,833,453	3,282,622	0.0357	0.9643	86.72
19.5	71,581,658	142,694	0.0020	0.9980	83.62
20.5	75,795,688	1,059,438	0.0140	0.9860	83.45
21.5	67,090,710	153,792	0.0023	0.9977	82.29
22.5	65,234,526	37,460	0.0006	0.9994	82.10
23.5	59,392,884	1,211,948	0.0204	0.9796	82.05
24.5	56,072,668	15,339	0.0003	0.9997	80.38
25.5	56,497,338	1,658,760	0.0294	0.9706	80.35
26.5	56,294,978	2,787,190	0.0495	0.9505	77.99
27.5	53,469,281	304,505	0.0057	0.9943	74.13
28.5	52,216,843	311,308	0.0060	0.9940	73.71
29.5	88,967,826	13,670	0.0002	0.9998	73.27
30.5	76,783,058	254,000	0.0033	0.9967	73.26
31.5	73,481,764	87,005	0.0012	0.9988	73.02
32.5	72,094,952	291,170	0.0040	0.9960	72.93
33.5	68,656,324	2,932,938	0.0427	0.9573	72.64
34.5	64,887,582	446,584	0.0069	0.9931	69.53
35.5	74,166,222	562,512	0.0076	0.9924	69.06
36.5	101,721,967	293,653	0.0029	0.9971	68.53
37.5	103,278,622	263,818	0.0026	0.9974	68.33
38.5	107,514,283	1,262,210	0.0117	0.9883	68.16

KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

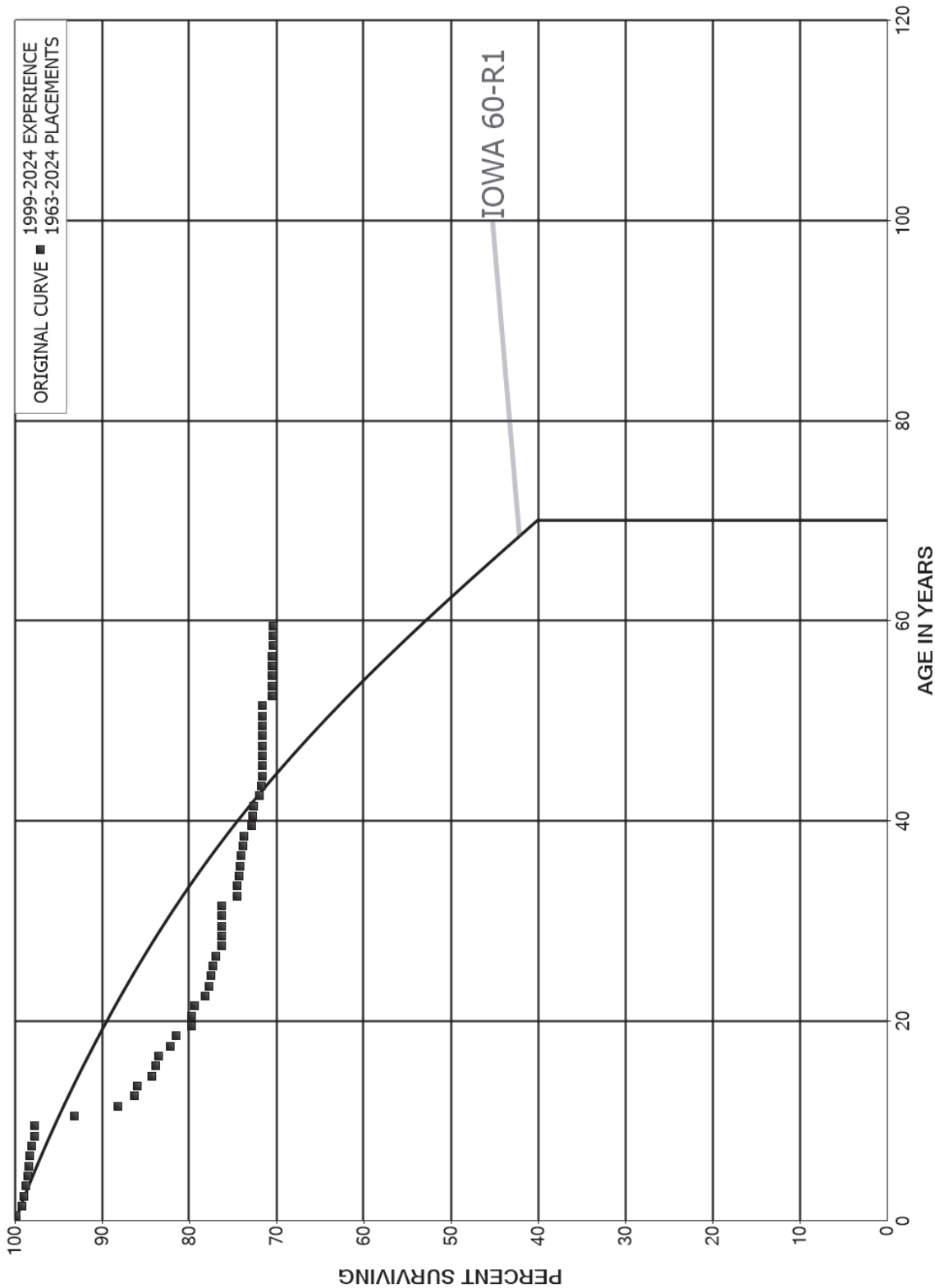
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2024

EXPERIENCE BAND 1999-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	106,594,046	4,257,131	0.0399	0.9601	67.36
40.5	100,356,573	620,462	0.0062	0.9938	64.67
41.5	98,779,560	653,508	0.0066	0.9934	64.27
42.5	100,414,629	219,186	0.0022	0.9978	63.84
43.5	131,070,731	1,232,639	0.0094	0.9906	63.70
44.5	127,255,220	2,212,326	0.0174	0.9826	63.11
45.5	121,652,124	481,369	0.0040	0.9960	62.01
46.5	53,352,583	101,248	0.0019	0.9981	61.76
47.5	46,859,439	441,595	0.0094	0.9906	61.65
48.5	41,246,478	65,980	0.0016	0.9984	61.06
49.5	40,671,747	96,708	0.0024	0.9976	60.97
50.5	40,268,655	1,818,503	0.0452	0.9548	60.82
51.5	38,043,992	74,209	0.0020	0.9980	58.08
52.5	33,396,088	188,735	0.0057	0.9943	57.96
53.5	2,428,907	19,754	0.0081	0.9919	57.63
54.5	2,201,273	14,824	0.0067	0.9933	57.17
55.5	2,186,449	1,183	0.0005	0.9995	56.78
56.5	2,157,320	28,693	0.0133	0.9867	56.75
57.5	2,127,656	1,765	0.0008	0.9992	56.00
58.5	2,100,150	3,262	0.0016	0.9984	55.95
59.5	2,073,908	1,124	0.0005	0.9995	55.86
60.5	1,998,653	376,263	0.1883	0.8117	55.83
61.5					45.32

KENTUCKY POWER COMPANY  
ACCOUNT 314.00 TURBOGENERATOR UNITS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2024

EXPERIENCE BAND 1999-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	76,112,900	115,133	0.0015	0.9985	100.00
0.5	85,821,344	615,064	0.0072	0.9928	99.85
1.5	84,752,009	200,464	0.0024	0.9976	99.13
2.5	83,471,829	139,077	0.0017	0.9983	98.90
3.5	85,533,854	162,447	0.0019	0.9981	98.73
4.5	86,263,626	151,366	0.0018	0.9982	98.55
5.5	87,525,898	107,648	0.0012	0.9988	98.37
6.5	83,306,684	198,437	0.0024	0.9976	98.25
7.5	82,902,426	202,052	0.0024	0.9976	98.02
8.5	83,681,686	44,616	0.0005	0.9995	97.78
9.5	86,948,687	4,095,582	0.0471	0.9529	97.73
10.5	86,050,154	4,543,541	0.0528	0.9472	93.12
11.5	78,225,465	1,656,249	0.0212	0.9788	88.21
12.5	75,355,239	383,929	0.0051	0.9949	86.34
13.5	71,724,038	1,321,789	0.0184	0.9816	85.90
14.5	71,836,500	454,748	0.0063	0.9937	84.32
15.5	72,845,771	275,584	0.0038	0.9962	83.78
16.5	43,090,601	662,710	0.0154	0.9846	83.47
17.5	38,509,793	292,859	0.0076	0.9924	82.18
18.5	37,399,304	845,314	0.0226	0.9774	81.56
19.5	31,928,536	8,668	0.0003	0.9997	79.71
20.5	30,851,000	112,866	0.0037	0.9963	79.69
21.5	33,466,997	533,125	0.0159	0.9841	79.40
22.5	31,823,995	187,186	0.0059	0.9941	78.14
23.5	31,551,401	89,764	0.0028	0.9972	77.68
24.5	30,080,461	64,210	0.0021	0.9979	77.46
25.5	30,002,618	126,887	0.0042	0.9958	77.29
26.5	25,923,573	215,674	0.0083	0.9917	76.96
27.5	23,802,883		0.0000	1.0000	76.32
28.5	24,157,733	2,200	0.0001	0.9999	76.32
29.5	43,535,375		0.0000	1.0000	76.32
30.5	43,291,903	13,172	0.0003	0.9997	76.32
31.5	38,884,942	919,895	0.0237	0.9763	76.29
32.5	34,629,630		0.0000	1.0000	74.49
33.5	33,823,946	107,025	0.0032	0.9968	74.49
34.5	32,107,955	17,054	0.0005	0.9995	74.25
35.5	35,929,841	62,620	0.0017	0.9983	74.21
36.5	32,730,736	86,828	0.0027	0.9973	74.08
37.5	32,137,312	70,300	0.0022	0.9978	73.89
38.5	31,931,707	399,262	0.0125	0.9875	73.73

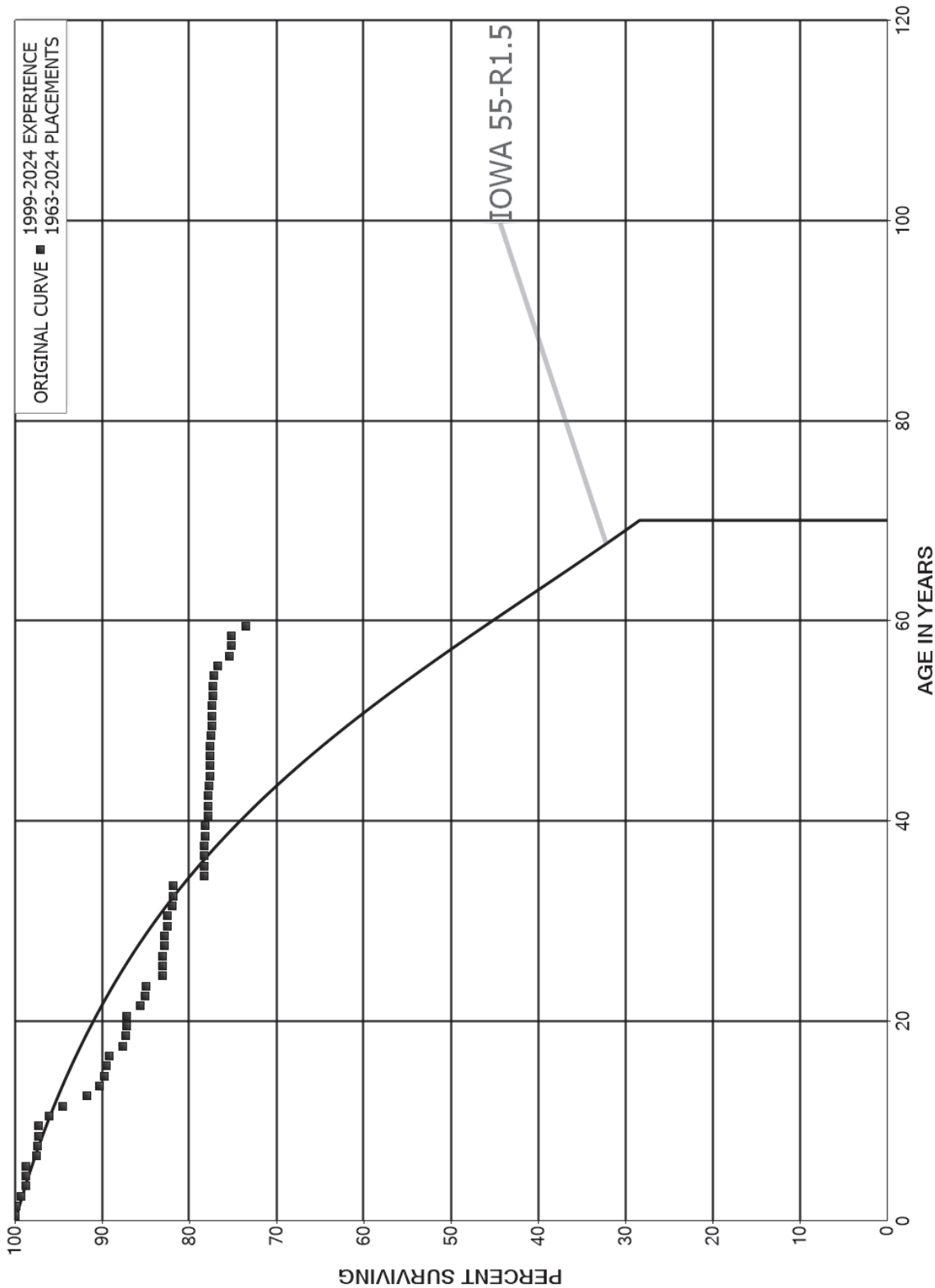
KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2024			EXPERIENCE BAND 1999-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	31,492,566	48,488	0.0015	0.9985	72.80
40.5	30,801,578	24,298	0.0008	0.9992	72.69
41.5	30,351,120	293,905	0.0097	0.9903	72.63
42.5	30,025,404	92,818	0.0031	0.9969	71.93
43.5	49,610,851	34,613	0.0007	0.9993	71.71
44.5	49,246,320	21,321	0.0004	0.9996	71.66
45.5	48,517,849		0.0000	1.0000	71.63
46.5	28,139,304	9	0.0000	1.0000	71.63
47.5	28,074,158	82	0.0000	1.0000	71.63
48.5	27,991,250		0.0000	1.0000	71.63
49.5	27,733,510		0.0000	1.0000	71.63
50.5	27,355,591		0.0000	1.0000	71.63
51.5	27,299,741	424,605	0.0156	0.9844	71.63
52.5	26,565,574		0.0000	1.0000	70.51
53.5	5,848,648	1,423	0.0002	0.9998	70.51
54.5	5,436,127	2,516	0.0005	0.9995	70.50
55.5	5,433,611		0.0000	1.0000	70.46
56.5	5,433,611	5,375	0.0010	0.9990	70.46
57.5	5,428,237		0.0000	1.0000	70.39
58.5	5,369,049		0.0000	1.0000	70.39
59.5	5,369,043	655	0.0001	0.9999	70.39
60.5	5,368,387	1,187	0.0002	0.9998	70.38
61.5					70.37

KENTUCKY POWER COMPANY  
ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2024

EXPERIENCE BAND 1999-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,669,635		0.0000	1.0000	100.00
0.5	16,150,665	34,798	0.0022	0.9978	100.00
1.5	18,969,170	91,004	0.0048	0.9952	99.78
2.5	18,954,223	107,152	0.0057	0.9943	99.31
3.5	19,183,785	1,659	0.0001	0.9999	98.74
4.5	19,068,885		0.0000	1.0000	98.74
5.5	18,555,867	229,585	0.0124	0.9876	98.74
6.5	16,396,400	26,385	0.0016	0.9984	97.51
7.5	16,177,441	8,504	0.0005	0.9995	97.36
8.5	15,847,184	8,007	0.0005	0.9995	97.31
9.5	9,139,841	113,024	0.0124	0.9876	97.26
10.5	8,828,105	139,644	0.0158	0.9842	96.05
11.5	6,974,786	206,952	0.0297	0.9703	94.53
12.5	5,871,198	89,889	0.0153	0.9847	91.73
13.5	5,000,429	35,364	0.0071	0.9929	90.33
14.5	4,800,301	9,257	0.0019	0.9981	89.69
15.5	4,607,874	15,062	0.0033	0.9967	89.51
16.5	4,887,313	86,301	0.0177	0.9823	89.22
17.5	4,772,951	21,678	0.0045	0.9955	87.65
18.5	3,918,641	2,189	0.0006	0.9994	87.25
19.5	3,237,378	1,769	0.0005	0.9995	87.20
20.5	3,445,036	61,653	0.0179	0.9821	87.15
21.5	3,142,812	17,441	0.0055	0.9945	85.59
22.5	3,341,507	7,502	0.0022	0.9978	85.12
23.5	3,492,803	77,673	0.0222	0.9778	84.93
24.5	3,332,897		0.0000	1.0000	83.04
25.5	3,519,112		0.0000	1.0000	83.04
26.5	3,346,785	9,539	0.0029	0.9971	83.04
27.5	3,508,202		0.0000	1.0000	82.80
28.5	3,884,323	13,944	0.0036	0.9964	82.80
29.5	10,039,813		0.0000	1.0000	82.50
30.5	10,078,717	68,050	0.0068	0.9932	82.50
31.5	11,085,921	8,160	0.0007	0.9993	81.95
32.5	10,964,077	1,881	0.0002	0.9998	81.89
33.5	10,474,658	460,068	0.0439	0.9561	81.87
34.5	9,650,485	492	0.0001	0.9999	78.28
35.5	10,839,744	3,524	0.0003	0.9997	78.27
36.5	15,032,137	2,397	0.0002	0.9998	78.25
37.5	14,676,161	8,069	0.0005	0.9995	78.23
38.5	14,584,355	11,137	0.0008	0.9992	78.19



KENTUCKY POWER COMPANY

ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT

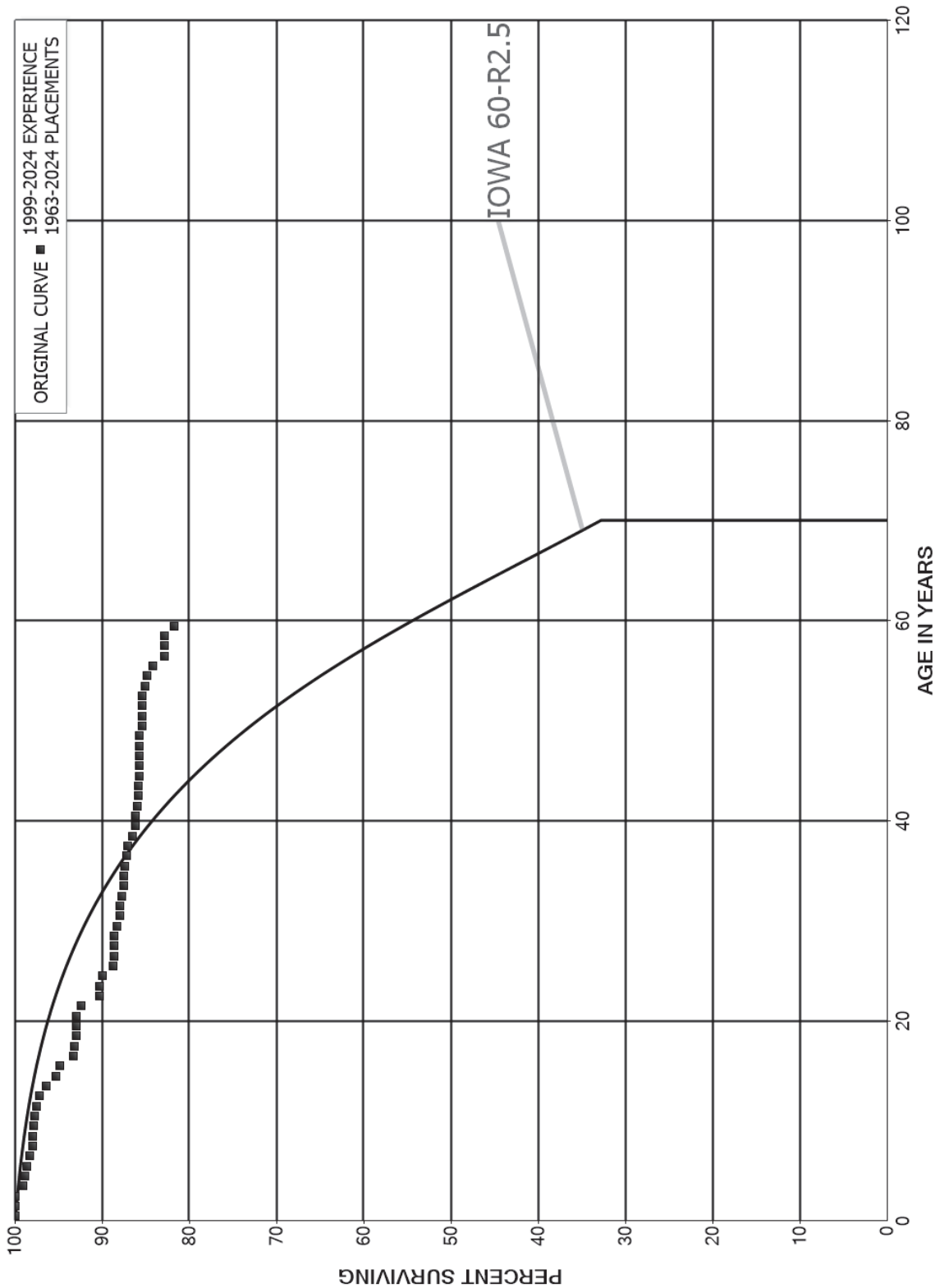
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2024

EXPERIENCE BAND 1999-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	14,264,767	47,115	0.0033	0.9967	78.13
40.5	14,019,945	1,782	0.0001	0.9999	77.87
41.5	13,259,620		0.0000	1.0000	77.86
42.5	13,428,838	27,626	0.0021	0.9979	77.86
43.5	19,375,648	9,744	0.0005	0.9995	77.70
44.5	19,059,578	4,473	0.0002	0.9998	77.66
45.5	18,612,915	7,477	0.0004	0.9996	77.65
46.5	8,280,922	1,545	0.0002	0.9998	77.61
47.5	8,221,051	14,114	0.0017	0.9983	77.60
48.5	8,133,994	8,352	0.0010	0.9990	77.47
49.5	8,125,641	774	0.0001	0.9999	77.39
50.5	8,120,537	453	0.0001	0.9999	77.38
51.5	8,092,369	6,543	0.0008	0.9992	77.38
52.5	7,730,702	1,424	0.0002	0.9998	77.31
53.5	1,589,882	2,508	0.0016	0.9984	77.30
54.5	1,453,031	7,484	0.0052	0.9948	77.18
55.5	1,445,547	26,879	0.0186	0.9814	76.78
56.5	1,418,668	2,743	0.0019	0.9981	75.35
57.5	1,415,925	307	0.0002	0.9998	75.21
58.5	1,415,618	31,955	0.0226	0.9774	75.19
59.5	1,382,273		0.0000	1.0000	73.49
60.5	1,382,273	38,652	0.0280	0.9720	73.49
61.5					71.44

KENTUCKY POWER COMPANY  
ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2024

EXPERIENCE BAND 1999-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,388,869	1,679	0.0002	0.9998	100.00
0.5	8,145,572	1	0.0000	1.0000	99.98
1.5	7,481,153		0.0000	1.0000	99.98
2.5	7,103,716	62,834	0.0088	0.9912	99.98
3.5	7,262,117	16,109	0.0022	0.9978	99.10
4.5	8,766,258	19,757	0.0023	0.9977	98.88
5.5	9,845,698	40,939	0.0042	0.9958	98.65
6.5	9,439,292	26,633	0.0028	0.9972	98.24
7.5	9,036,547		0.0000	1.0000	97.97
8.5	8,561,269	9,786	0.0011	0.9989	97.97
9.5	8,250,956	12,478	0.0015	0.9985	97.85
10.5	8,441,795	19,497	0.0023	0.9977	97.71
11.5	7,881,194	23,210	0.0029	0.9971	97.48
12.5	7,197,944	55,351	0.0077	0.9923	97.19
13.5	6,797,550	82,967	0.0122	0.9878	96.45
14.5	6,208,116	27,873	0.0045	0.9955	95.27
15.5	4,264,820	68,182	0.0160	0.9840	94.84
16.5	4,143,634	7,080	0.0017	0.9983	93.32
17.5	3,958,906	8,822	0.0022	0.9978	93.16
18.5	3,575,285		0.0000	1.0000	92.96
19.5	3,322,712	839	0.0003	0.9997	92.96
20.5	2,786,288	15,793	0.0057	0.9943	92.93
21.5	1,858,976	42,162	0.0227	0.9773	92.41
22.5	1,744,409	2	0.0000	1.0000	90.31
23.5	1,805,779	6,674	0.0037	0.9963	90.31
24.5	1,675,813	22,666	0.0135	0.9865	89.98
25.5	1,663,966	2,329	0.0014	0.9986	88.76
26.5	1,599,569		0.0000	1.0000	88.64
27.5	1,598,898		0.0000	1.0000	88.64
28.5	1,763,314	5,967	0.0034	0.9966	88.64
29.5	3,233,078	16,274	0.0050	0.9950	88.34
30.5	2,853,338		0.0000	1.0000	87.89
31.5	2,791,154	4,332	0.0016	0.9984	87.89
32.5	2,761,180	6,234	0.0023	0.9977	87.76
33.5	2,690,084		0.0000	1.0000	87.56
34.5	2,609,373	5,752	0.0022	0.9978	87.56
35.5	3,373,880	7,785	0.0023	0.9977	87.36
36.5	3,555,067	3,193	0.0009	0.9991	87.16
37.5	3,513,545	23,486	0.0067	0.9933	87.08
38.5	3,427,282	11,411	0.0033	0.9967	86.50

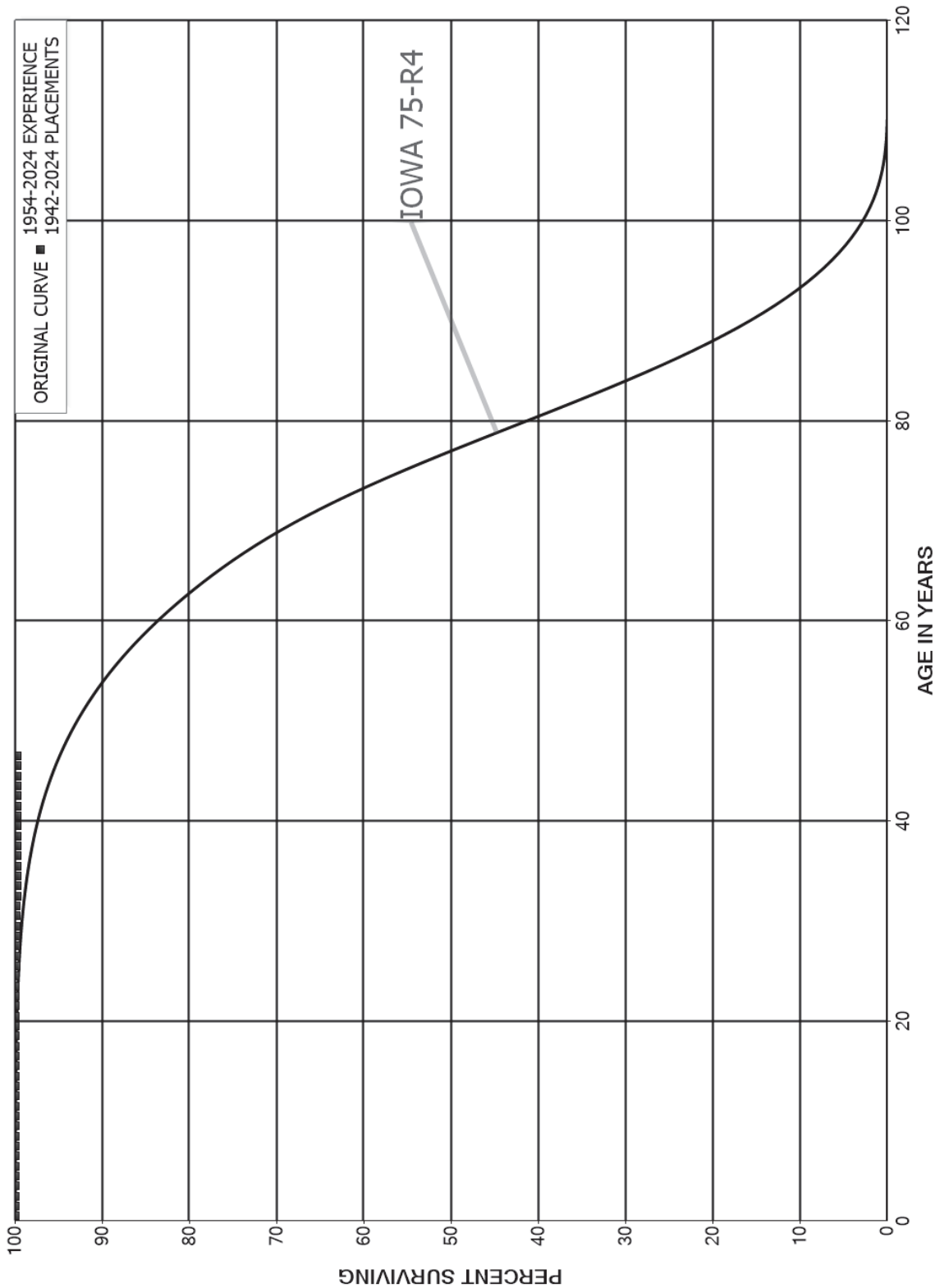
KENTUCKY POWER COMPANY

ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2024			EXPERIENCE BAND 1999-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,358,857	1,430	0.0004	0.9996	86.21
40.5	3,188,547	9,951	0.0031	0.9969	86.18
41.5	3,169,558	1,860	0.0006	0.9994	85.91
42.5	3,180,583	630	0.0002	0.9998	85.86
43.5	4,806,038	3,506	0.0007	0.9993	85.84
44.5	4,721,825		0.0000	1.0000	85.78
45.5	4,550,379	2	0.0000	1.0000	85.78
46.5	2,788,064		0.0000	1.0000	85.78
47.5	2,770,643		0.0000	1.0000	85.78
48.5	2,754,317	13,173	0.0048	0.9952	85.78
49.5	2,692,581		0.0000	1.0000	85.37
50.5	2,686,057		0.0000	1.0000	85.37
51.5	2,670,219	360	0.0001	0.9999	85.37
52.5	2,447,663	7,865	0.0032	0.9968	85.36
53.5	737,614	2,495	0.0034	0.9966	85.08
54.5	679,198	4,735	0.0070	0.9930	84.79
55.5	674,463	11,217	0.0166	0.9834	84.20
56.5	660,010		0.0000	1.0000	82.80
57.5	657,989		0.0000	1.0000	82.80
58.5	650,763	8,480	0.0130	0.9870	82.80
59.5	637,680	1,716	0.0027	0.9973	81.72
60.5	631,961		0.0000	1.0000	81.50
61.5					81.50

KENTUCKY POWER COMPANY  
ACCOUNT 350.10 LAND RIGHTS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 350.10 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1942-2024

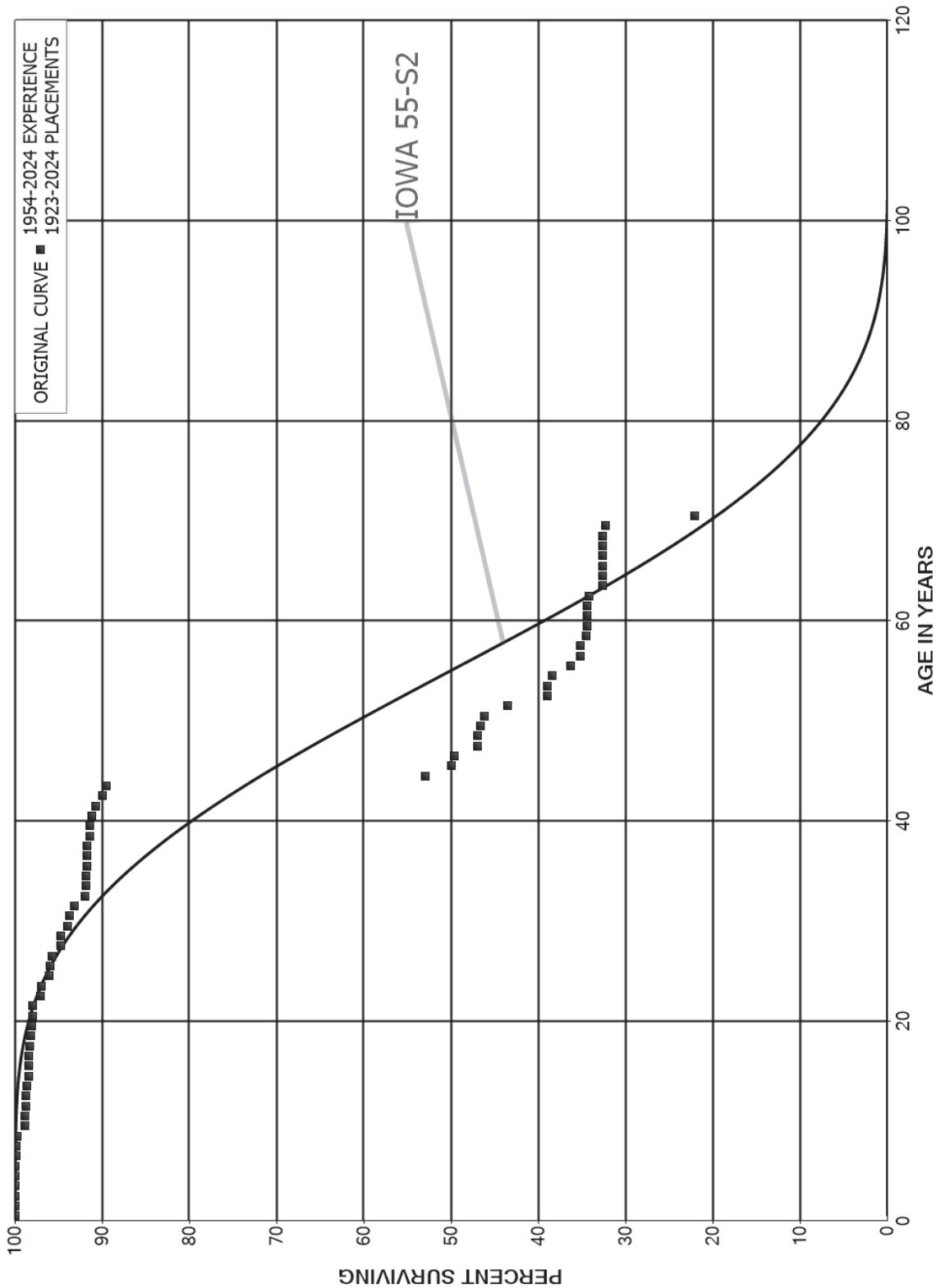
EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	39,909,272		0.0000	1.0000	100.00
0.5	35,445,817		0.0000	1.0000	100.00
1.5	34,847,074		0.0000	1.0000	100.00
2.5	34,112,877		0.0000	1.0000	100.00
3.5	33,932,187		0.0000	1.0000	100.00
4.5	32,461,605		0.0000	1.0000	100.00
5.5	31,428,406	1	0.0000	1.0000	100.00
6.5	30,582,240		0.0000	1.0000	100.00
7.5	30,567,316		0.0000	1.0000	100.00
8.5	30,551,233		0.0000	1.0000	100.00
9.5	30,480,703		0.0000	1.0000	100.00
10.5	27,330,076		0.0000	1.0000	100.00
11.5	26,359,319		0.0000	1.0000	100.00
12.5	25,485,534		0.0000	1.0000	100.00
13.5	25,334,665		0.0000	1.0000	100.00
14.5	25,307,920		0.0000	1.0000	100.00
15.5	25,089,769		0.0000	1.0000	100.00
16.5	23,525,202	28	0.0000	1.0000	100.00
17.5	23,522,900	202	0.0000	1.0000	100.00
18.5	23,418,700	1,675	0.0001	0.9999	100.00
19.5	23,324,719		0.0000	1.0000	99.99
20.5	23,290,728	5,446	0.0002	0.9998	99.99
21.5	23,274,834		0.0000	1.0000	99.97
22.5	23,268,667	231	0.0000	1.0000	99.97
23.5	23,014,247		0.0000	1.0000	99.97
24.5	22,692,678	32,330	0.0014	0.9986	99.97
25.5	21,693,674	120	0.0000	1.0000	99.83
26.5	20,413,318	3,328	0.0002	0.9998	99.82
27.5	19,829,537	336	0.0000	1.0000	99.81
28.5	19,702,828	2,960	0.0002	0.9998	99.81
29.5	19,360,080	1,728	0.0001	0.9999	99.79
30.5	19,036,524	356	0.0000	1.0000	99.78
31.5	18,719,392	1,948	0.0001	0.9999	99.78
32.5	18,641,639		0.0000	1.0000	99.77
33.5	18,316,353	7	0.0000	1.0000	99.77
34.5	18,212,201		0.0000	1.0000	99.77
35.5	18,196,327		0.0000	1.0000	99.77
36.5	18,193,062		0.0000	1.0000	99.77
37.5	18,191,735		0.0000	1.0000	99.77
38.5	18,109,151		0.0000	1.0000	99.77

KENTUCKY POWER COMPANY  
ACCOUNT 350.10 LAND RIGHTS  
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1942-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,634,962		0.0000	1.0000	99.77
40.5	5,340,700		0.0000	1.0000	99.77
41.5	4,838,669		0.0000	1.0000	99.77
42.5	4,689,813		0.0000	1.0000	99.77
43.5	4,535,172		0.0000	1.0000	99.77
44.5	4,275,480		0.0000	1.0000	99.77
45.5	38,729		0.0000	1.0000	99.77
46.5	38,729		0.0000	1.0000	99.77
47.5	38,729		0.0000	1.0000	99.77
48.5	38,729		0.0000	1.0000	99.77
49.5					99.77

KENTUCKY POWER COMPANY  
ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS  
ORIGINAL AND SMOOTH SURVIVOR CURVES





KENTUCKY POWER COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	31,859,722		0.0000	1.0000	100.00
0.5	18,909,226	63	0.0000	1.0000	100.00
1.5	16,821,967	1,051	0.0001	0.9999	100.00
2.5	16,706,407	1,954	0.0001	0.9999	99.99
3.5	12,204,115	2,277	0.0002	0.9998	99.98
4.5	9,382,397	3,388	0.0004	0.9996	99.96
5.5	7,685,241	6,248	0.0008	0.9992	99.93
6.5	7,081,914	2,450	0.0003	0.9997	99.85
7.5	6,867,815	2,847	0.0004	0.9996	99.81
8.5	6,860,128	61,613	0.0090	0.9910	99.77
9.5	6,800,860	6,431	0.0009	0.9991	98.87
10.5	6,804,655	885	0.0001	0.9999	98.78
11.5	6,810,483	271	0.0000	1.0000	98.77
12.5	6,810,468	8,722	0.0013	0.9987	98.76
13.5	6,740,727	12,986	0.0019	0.9981	98.64
14.5	6,650,662	5,700	0.0009	0.9991	98.45
15.5	6,501,647	1,452	0.0002	0.9998	98.36
16.5	6,359,062	267	0.0000	1.0000	98.34
17.5	6,279,621	7,399	0.0012	0.9988	98.34
18.5	6,272,222	8,385	0.0013	0.9987	98.22
19.5	6,197,622	9,156	0.0015	0.9985	98.09
20.5	6,188,466	880	0.0001	0.9999	97.94
21.5	6,187,586	56,385	0.0091	0.9909	97.93
22.5	5,325,155	2,937	0.0006	0.9994	97.04
23.5	5,352,309	51,842	0.0097	0.9903	96.98
24.5	5,232,076	7,991	0.0015	0.9985	96.05
25.5	5,212,319	11,981	0.0023	0.9977	95.90
26.5	5,188,070	50,155	0.0097	0.9903	95.68
27.5	4,991,493	626	0.0001	0.9999	94.75
28.5	4,872,364	41,351	0.0085	0.9915	94.74
29.5	4,719,599	8,142	0.0017	0.9983	93.94
30.5	4,687,682	30,168	0.0064	0.9936	93.78
31.5	4,303,173	57,277	0.0133	0.9867	93.17
32.5	4,226,184	5,583	0.0013	0.9987	91.93
33.5	4,185,697	852	0.0002	0.9998	91.81
34.5	4,119,454	2,221	0.0005	0.9995	91.79
35.5	4,115,723	1,334	0.0003	0.9997	91.74
36.5	4,111,456	200	0.0000	1.0000	91.71
37.5	4,097,415	14,392	0.0035	0.9965	91.71
38.5	3,927,042		0.0000	1.0000	91.39

KENTUCKY POWER COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,870,741	11,066	0.0029	0.9971	91.39
40.5	3,744,694	14,811	0.0040	0.9960	91.12
41.5	3,677,734	32,810	0.0089	0.9911	90.76
42.5	3,464,394	17,400	0.0050	0.9950	89.95
43.5	1,816,280	741,274	0.4081	0.5919	89.50
44.5	998,691	58,098	0.0582	0.9418	52.97
45.5	937,470	5,890	0.0063	0.9937	49.89
46.5	931,455	50,023	0.0537	0.9463	49.58
47.5	848,860		0.0000	1.0000	46.92
48.5	785,515	4,474	0.0057	0.9943	46.92
49.5	775,945	8,150	0.0105	0.9895	46.65
50.5	293,948	16,557	0.0563	0.9437	46.16
51.5	232,517	24,583	0.1057	0.8943	43.56
52.5	207,934	250	0.0012	0.9988	38.95
53.5	203,312	2,896	0.0142	0.9858	38.91
54.5	178,667	9,397	0.0526	0.9474	38.35
55.5	168,018	5,332	0.0317	0.9683	36.34
56.5	142,495		0.0000	1.0000	35.18
57.5	122,326	2,351	0.0192	0.9808	35.18
58.5	102,111	352	0.0034	0.9966	34.51
59.5	101,462	121	0.0012	0.9988	34.39
60.5	94,914		0.0000	1.0000	34.35
61.5	79,370	495	0.0062	0.9938	34.35
62.5	75,089	3,441	0.0458	0.9542	34.13
63.5	71,648		0.0000	1.0000	32.57
64.5	68,838		0.0000	1.0000	32.57
65.5	67,413		0.0000	1.0000	32.57
66.5	66,440		0.0000	1.0000	32.57
67.5	65,861		0.0000	1.0000	32.57
68.5	65,480	482	0.0074	0.9926	32.57
69.5	64,483	20,565	0.3189	0.6811	32.33
70.5	18,550		0.0000	1.0000	22.02
71.5	18,321		0.0000	1.0000	22.02
72.5	18,229	1,928	0.1058	0.8942	22.02
73.5	14,900		0.0000	1.0000	19.69
74.5	14,900		0.0000	1.0000	19.69
75.5	14,900		0.0000	1.0000	19.69
76.5	14,900		0.0000	1.0000	19.69
77.5	14,900		0.0000	1.0000	19.69
78.5	14,900		0.0000	1.0000	19.69

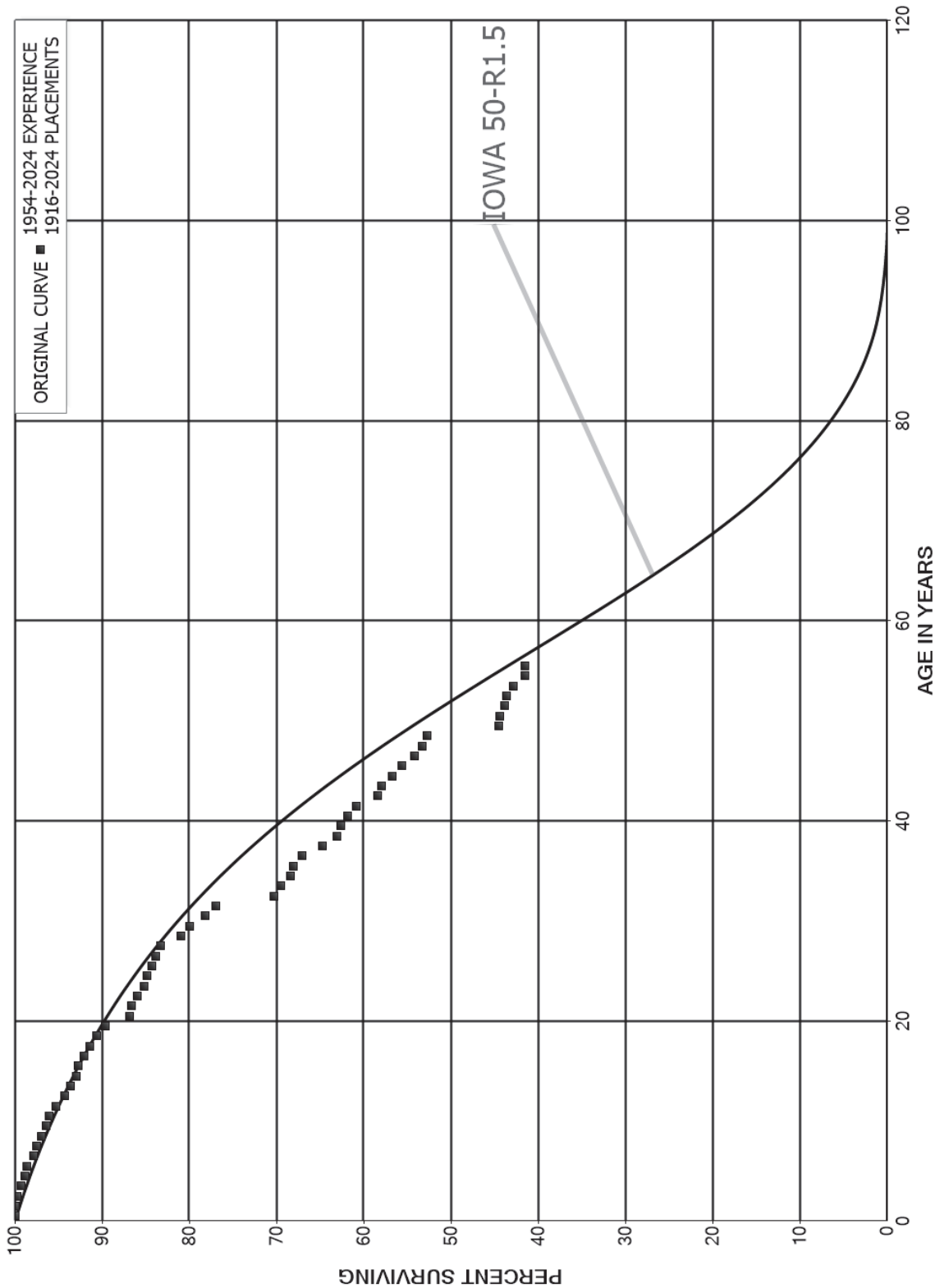
KENTUCKY POWER COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	14,900		0.0000	1.0000	19.69
80.5	12,763	3,055	0.2394	0.7606	19.69
81.5	7,335		0.0000	1.0000	14.98
82.5					14.98

KENTUCKY POWER COMPANY  
ACCOUNT 353.00 STATION EQUIPMENT  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1916-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	358,214,037	112,017	0.0003	0.9997	100.00
0.5	336,437,731	178,275	0.0005	0.9995	99.97
1.5	321,776,167	619,184	0.0019	0.9981	99.92
2.5	305,024,876	1,377,328	0.0045	0.9955	99.72
3.5	269,774,897	1,122,214	0.0042	0.9958	99.27
4.5	258,328,379	699,025	0.0027	0.9973	98.86
5.5	240,076,489	1,832,014	0.0076	0.9924	98.59
6.5	228,344,207	846,600	0.0037	0.9963	97.84
7.5	221,101,510	1,332,402	0.0060	0.9940	97.48
8.5	215,567,782	1,211,554	0.0056	0.9944	96.89
9.5	209,454,558	722,453	0.0034	0.9966	96.35
10.5	200,391,744	1,461,761	0.0073	0.9927	96.01
11.5	194,465,795	2,166,559	0.0111	0.9889	95.31
12.5	181,178,238	1,120,580	0.0062	0.9938	94.25
13.5	172,418,982	1,288,494	0.0075	0.9925	93.67
14.5	166,270,973	481,767	0.0029	0.9971	92.97
15.5	161,426,144	1,182,525	0.0073	0.9927	92.70
16.5	147,095,780	928,809	0.0063	0.9937	92.02
17.5	144,633,746	1,244,685	0.0086	0.9914	91.44
18.5	132,472,867	1,474,496	0.0111	0.9889	90.65
19.5	129,131,847	4,081,590	0.0316	0.9684	89.64
20.5	122,679,816	272,836	0.0022	0.9978	86.81
21.5	119,190,173	872,459	0.0073	0.9927	86.62
22.5	114,985,141	1,081,931	0.0094	0.9906	85.98
23.5	110,582,009	458,601	0.0041	0.9959	85.17
24.5	108,072,258	667,277	0.0062	0.9938	84.82
25.5	106,178,744	521,940	0.0049	0.9951	84.30
26.5	94,989,898	708,399	0.0075	0.9925	83.88
27.5	61,657,099	1,723,580	0.0280	0.9720	83.26
28.5	57,752,273	731,925	0.0127	0.9873	80.93
29.5	56,113,463	1,195,991	0.0213	0.9787	79.90
30.5	52,329,913	812,366	0.0155	0.9845	78.20
31.5	46,705,296	4,038,463	0.0865	0.9135	76.99
32.5	40,776,584	496,280	0.0122	0.9878	70.33
33.5	36,614,985	551,229	0.0151	0.9849	69.47
34.5	34,914,211	162,289	0.0046	0.9954	68.43
35.5	31,431,492	458,413	0.0146	0.9854	68.11
36.5	30,507,598	1,078,859	0.0354	0.9646	67.12
37.5	27,772,703	718,805	0.0259	0.9741	64.74
38.5	26,682,359	197,633	0.0074	0.9926	63.07

KENTUCKY POWER COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

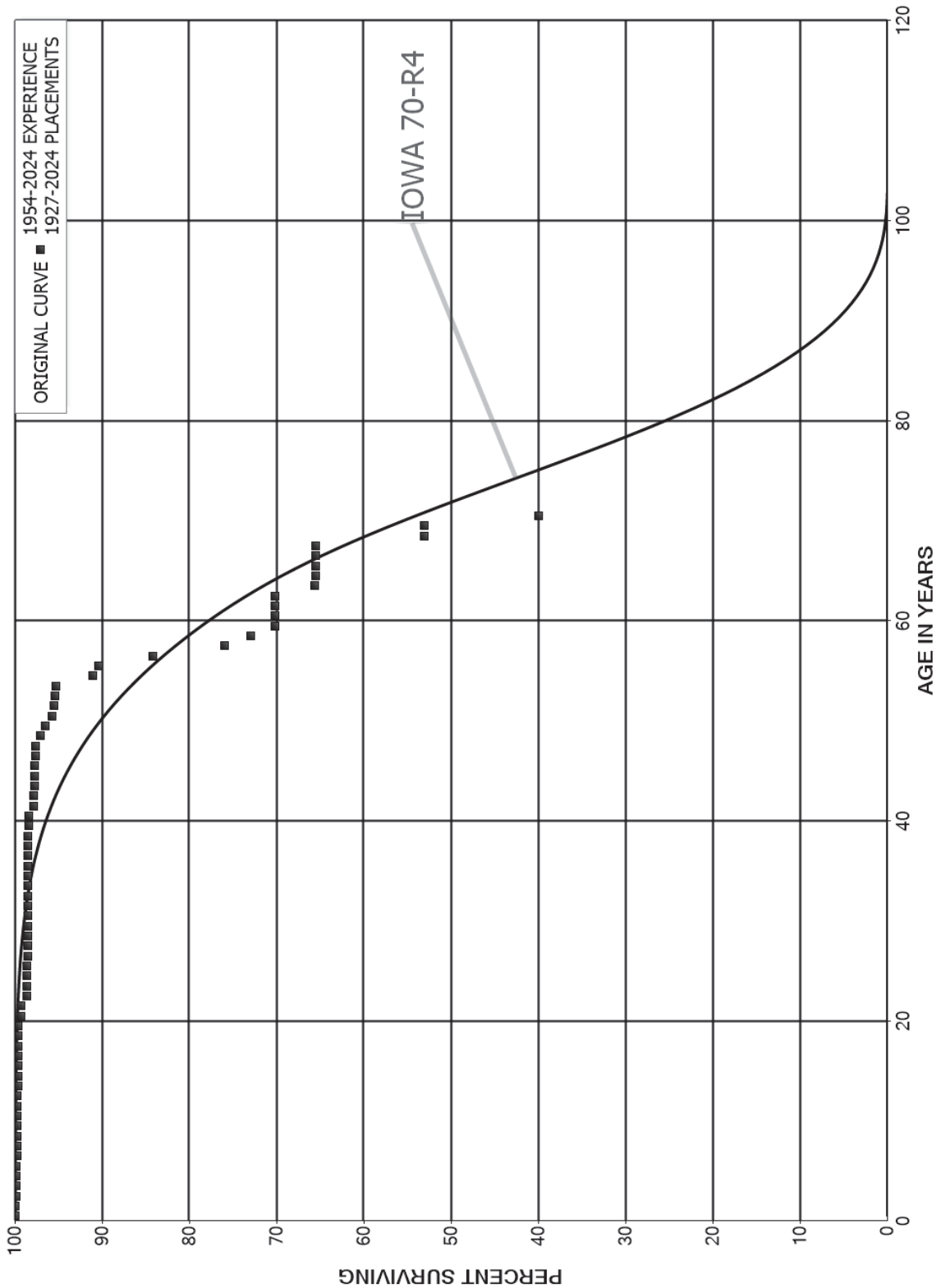
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	25,823,581	322,421	0.0125	0.9875	62.60
40.5	25,351,397	385,361	0.0152	0.9848	61.82
41.5	24,754,228	995,683	0.0402	0.9598	60.88
42.5	22,661,714	205,563	0.0091	0.9909	58.43
43.5	18,458,261	361,100	0.0196	0.9804	57.90
44.5	13,729,199	290,450	0.0212	0.9788	56.77
45.5	12,787,338	323,382	0.0253	0.9747	55.57
46.5	11,985,884	193,356	0.0161	0.9839	54.16
47.5	10,524,102	114,342	0.0109	0.9891	53.29
48.5	9,326,069	1,458,600	0.1564	0.8436	52.71
49.5	7,104,484	19,740	0.0028	0.9972	44.46
50.5	6,161,095	72,324	0.0117	0.9883	44.34
51.5	5,877,974	31,638	0.0054	0.9946	43.82
52.5	5,634,215	97,489	0.0173	0.9827	43.58
53.5	3,762,490	113,774	0.0302	0.9698	42.83
54.5	3,065,092	1,101	0.0004	0.9996	41.54
55.5	1,009,326	12,766	0.0126	0.9874	41.52
56.5	964,317	2,388	0.0025	0.9975	41.00
57.5	762,230		0.0000	1.0000	40.89
58.5	756,387	13,553	0.0179	0.9821	40.89
59.5	731,207		0.0000	1.0000	40.16
60.5	730,588		0.0000	1.0000	40.16
61.5	289,427		0.0000	1.0000	40.16
62.5	289,427		0.0000	1.0000	40.16
63.5	289,080	8,910	0.0308	0.9692	40.16
64.5	256,721	2,522	0.0098	0.9902	38.92
65.5	233,778	608	0.0026	0.9974	38.54
66.5	232,593	3	0.0000	1.0000	38.44
67.5	225,126	0	0.0000	1.0000	38.44
68.5	225,126	779	0.0035	0.9965	38.44
69.5	223,450	29,060	0.1301	0.8699	38.31
70.5	7,575		0.0000	1.0000	33.33
71.5					33.33

KENTUCKY POWER COMPANY  
ACCOUNT 354.00 TOWERS AND FIXTURES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1927-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	126,788,354		0.0000	1.0000	100.00
0.5	103,745,562		0.0000	1.0000	100.00
1.5	103,745,562	177,806	0.0017	0.9983	100.00
2.5	102,763,118		0.0000	1.0000	99.83
3.5	101,752,255	764	0.0000	1.0000	99.83
4.5	101,751,491	33,710	0.0003	0.9997	99.83
5.5	101,717,781	29,167	0.0003	0.9997	99.79
6.5	97,705,352	4,733	0.0000	1.0000	99.77
7.5	97,700,619	1	0.0000	1.0000	99.76
8.5	97,691,576	5,906	0.0001	0.9999	99.76
9.5	97,687,040	8,980	0.0001	0.9999	99.76
10.5	93,188,830	259	0.0000	1.0000	99.75
11.5	93,267,614	62,250	0.0007	0.9993	99.75
12.5	93,167,224	15,681	0.0002	0.9998	99.68
13.5	93,154,179	924	0.0000	1.0000	99.66
14.5	93,128,990	30,533	0.0003	0.9997	99.66
15.5	92,961,666		0.0000	1.0000	99.63
16.5	90,227,140		0.0000	1.0000	99.63
17.5	90,227,602	9,454	0.0001	0.9999	99.63
18.5	90,218,148	33,036	0.0004	0.9996	99.62
19.5	90,169,086	292,413	0.0032	0.9968	99.58
20.5	89,871,281	14,276	0.0002	0.9998	99.26
21.5	89,830,081	529,220	0.0059	0.9941	99.24
22.5	89,204,718		0.0000	1.0000	98.66
23.5	88,208,505		0.0000	1.0000	98.66
24.5	87,655,227	310	0.0000	1.0000	98.66
25.5	82,946,151	136,425	0.0016	0.9984	98.66
26.5	78,486,315	353	0.0000	1.0000	98.50
27.5	77,625,686	109	0.0000	1.0000	98.50
28.5	77,284,394	23	0.0000	1.0000	98.50
29.5	76,968,737	5,908	0.0001	0.9999	98.50
30.5	76,962,829		0.0000	1.0000	98.49
31.5	76,780,164	2,557	0.0000	1.0000	98.49
32.5	76,737,239	3,317	0.0000	1.0000	98.48
33.5	76,733,907		0.0000	1.0000	98.48
34.5	76,733,070		0.0000	1.0000	98.48
35.5	76,733,070	13	0.0000	1.0000	98.48
36.5	76,733,057	4,472	0.0001	0.9999	98.48
37.5	76,728,585	2,123	0.0000	1.0000	98.47
38.5	76,079,759	56,308	0.0007	0.9993	98.47



KENTUCKY POWER COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1927-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,133,568	3,943	0.0002	0.9998	98.40
40.5	16,129,626	90,440	0.0056	0.9944	98.37
41.5	16,039,186		0.0000	1.0000	97.82
42.5	15,856,108	20,749	0.0013	0.9987	97.82
43.5	15,835,359		0.0000	1.0000	97.70
44.5	15,835,359		0.0000	1.0000	97.70
45.5	15,835,359	14,361	0.0009	0.9991	97.70
46.5	15,781,147		0.0000	1.0000	97.61
47.5	15,752,547	84,262	0.0053	0.9947	97.61
48.5	15,570,789	93,971	0.0060	0.9940	97.08
49.5	15,404,055	128,327	0.0083	0.9917	96.50
50.5	15,255,344	23,199	0.0015	0.9985	95.69
51.5	15,119,303	19,014	0.0013	0.9987	95.55
52.5	6,703,224	7,122	0.0011	0.9989	95.43
53.5	6,694,329	303,143	0.0453	0.9547	95.33
54.5	2,512,077	15,573	0.0062	0.9938	91.01
55.5	2,496,504	173,384	0.0695	0.9305	90.45
56.5	1,680,042	163,931	0.0976	0.9024	84.17
57.5	1,381,405	55,008	0.0398	0.9602	75.95
58.5	1,307,330	49,721	0.0380	0.9620	72.93
59.5	1,179,099	227	0.0002	0.9998	70.15
60.5	1,175,489		0.0000	1.0000	70.14
61.5	564,354		0.0000	1.0000	70.14
62.5	564,354	36,676	0.0650	0.9350	70.14
63.5	527,678	613	0.0012	0.9988	65.58
64.5	527,065		0.0000	1.0000	65.51
65.5	250,685	0	0.0000	1.0000	65.51
66.5	250,685		0.0000	1.0000	65.51
67.5	250,685	47,582	0.1898	0.8102	65.51
68.5	199,818		0.0000	1.0000	53.07
69.5	199,818	49,540	0.2479	0.7521	53.07
70.5	132,715		0.0000	1.0000	39.91
71.5	132,715		0.0000	1.0000	39.91
72.5	132,715		0.0000	1.0000	39.91
73.5	132,715	405	0.0031	0.9969	39.91
74.5	132,310	1	0.0000	1.0000	39.79
75.5	132,309		0.0000	1.0000	39.79
76.5	132,309		0.0000	1.0000	39.79
77.5	132,309	0	0.0000	1.0000	39.79
78.5	132,309	1,991	0.0150	0.9850	39.79

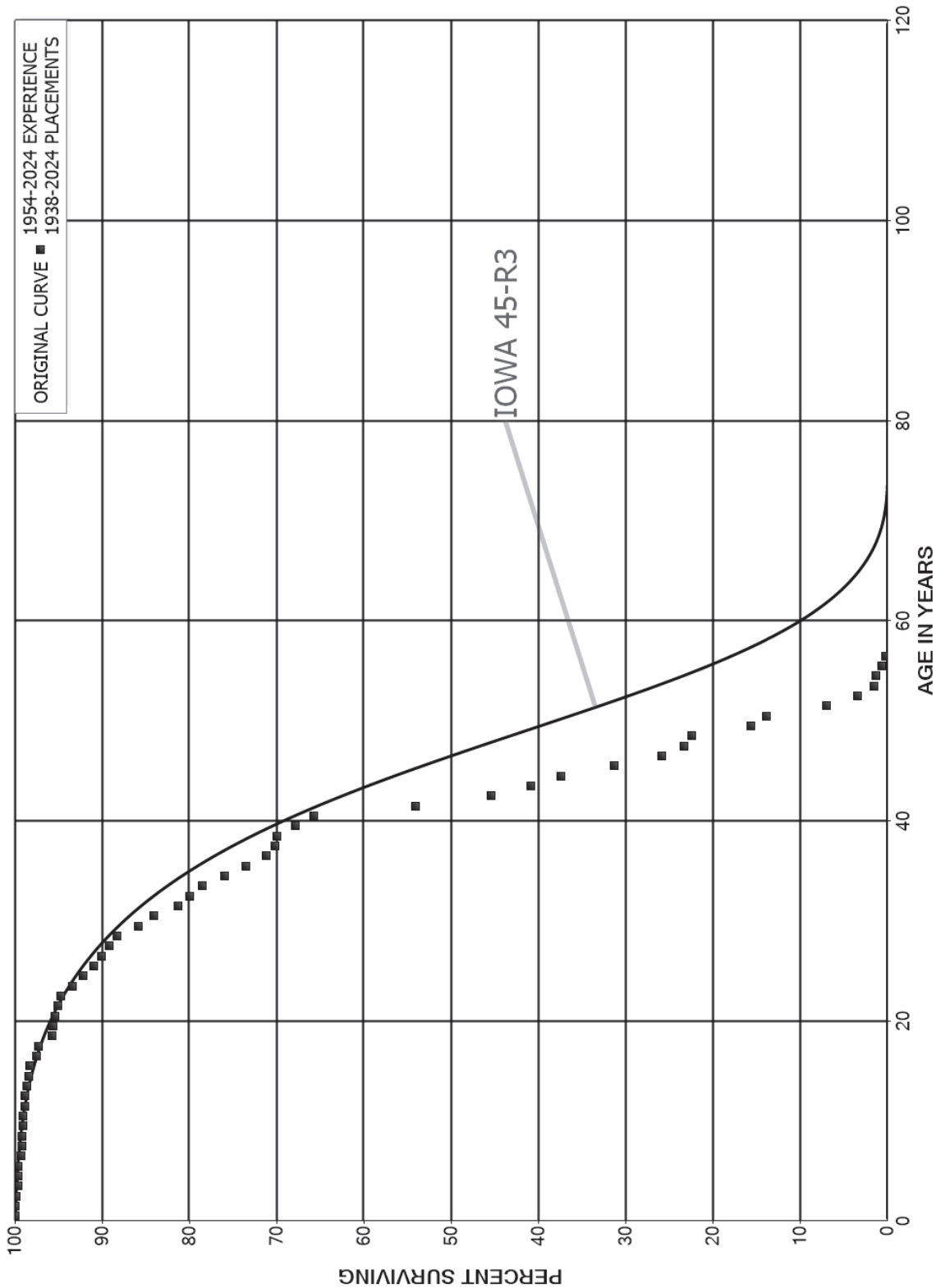
KENTUCKY POWER COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1927-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	130,318		0.0000	1.0000	39.19
80.5	129,561	0	0.0000	1.0000	39.19
81.5	129,561		0.0000	1.0000	39.19
82.5	36,810		0.0000	1.0000	39.19
83.5	36,810		0.0000	1.0000	39.19
84.5	36,132	593	0.0164	0.9836	39.19
85.5	35,284	59	0.0017	0.9983	38.55
86.5	28,131		0.0000	1.0000	38.49
87.5	28,131	3,107	0.1104	0.8896	38.49
88.5	25,024	4,423	0.1767	0.8233	34.23
89.5	20,601	317	0.0154	0.9846	28.18
90.5	20,285	45	0.0022	0.9978	27.75
91.5	20,240	18,136	0.8961	0.1039	27.69
92.5	2,104	0	0.0000	1.0000	2.88
93.5	2,104	0	0.0000	1.0000	2.88
94.5	2,104	1,558	0.7404	0.2596	2.88
95.5	546	546	1.0000	0.0000	0.75
96.5	0	0	1.0000		0.00
97.5					

KENTUCKY POWER COMPANY  
ACCOUNT 355.00 POLES AND FIXTURES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 355.00 POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	258,871,988	25,106	0.0001	0.9999	100.00
0.5	225,491,059	50,210	0.0002	0.9998	99.99
1.5	208,567,408	212,033	0.0010	0.9990	99.97
2.5	198,059,878	409,702	0.0021	0.9979	99.87
3.5	176,214,436	22,928	0.0001	0.9999	99.66
4.5	145,437,832	106,347	0.0007	0.9993	99.65
5.5	121,607,816	342,672	0.0028	0.9972	99.57
6.5	112,118,634	134,376	0.0012	0.9988	99.29
7.5	108,205,314	38,481	0.0004	0.9996	99.17
8.5	106,147,247	29,932	0.0003	0.9997	99.14
9.5	102,439,328	80,339	0.0008	0.9992	99.11
10.5	84,285,243	150,291	0.0018	0.9982	99.03
11.5	81,107,107	43,860	0.0005	0.9995	98.86
12.5	67,854,584	151,910	0.0022	0.9978	98.80
13.5	59,054,362	135,840	0.0023	0.9977	98.58
14.5	57,500,735	44,265	0.0008	0.9992	98.36
15.5	56,118,965	431,924	0.0077	0.9923	98.28
16.5	47,127,393	130,753	0.0028	0.9972	97.52
17.5	46,494,347	706,605	0.0152	0.9848	97.25
18.5	44,021,897	80,477	0.0018	0.9982	95.77
19.5	42,604,963	111,810	0.0026	0.9974	95.60
20.5	41,073,837	126,230	0.0031	0.9969	95.35
21.5	40,452,009	129,637	0.0032	0.9968	95.06
22.5	38,343,391	546,556	0.0143	0.9857	94.75
23.5	35,527,896	471,602	0.0133	0.9867	93.40
24.5	33,314,649	439,546	0.0132	0.9868	92.16
25.5	26,065,462	259,986	0.0100	0.9900	90.94
26.5	21,294,394	192,664	0.0090	0.9910	90.04
27.5	19,178,748	205,576	0.0107	0.9893	89.22
28.5	18,272,675	506,293	0.0277	0.9723	88.27
29.5	17,277,854	355,608	0.0206	0.9794	85.82
30.5	14,497,770	482,691	0.0333	0.9667	84.05
31.5	12,440,925	196,958	0.0158	0.9842	81.26
32.5	11,220,222	212,621	0.0189	0.9811	79.97
33.5	10,001,462	314,536	0.0314	0.9686	78.45
34.5	9,611,600	319,414	0.0332	0.9668	75.99
35.5	8,983,269	273,140	0.0304	0.9696	73.46
36.5	8,629,412	124,305	0.0144	0.9856	71.23
37.5	8,478,367	36,432	0.0043	0.9957	70.20
38.5	7,832,399	226,033	0.0289	0.9711	69.90

KENTUCKY POWER COMPANY

ACCOUNT 355.00 POLES AND FIXTURES

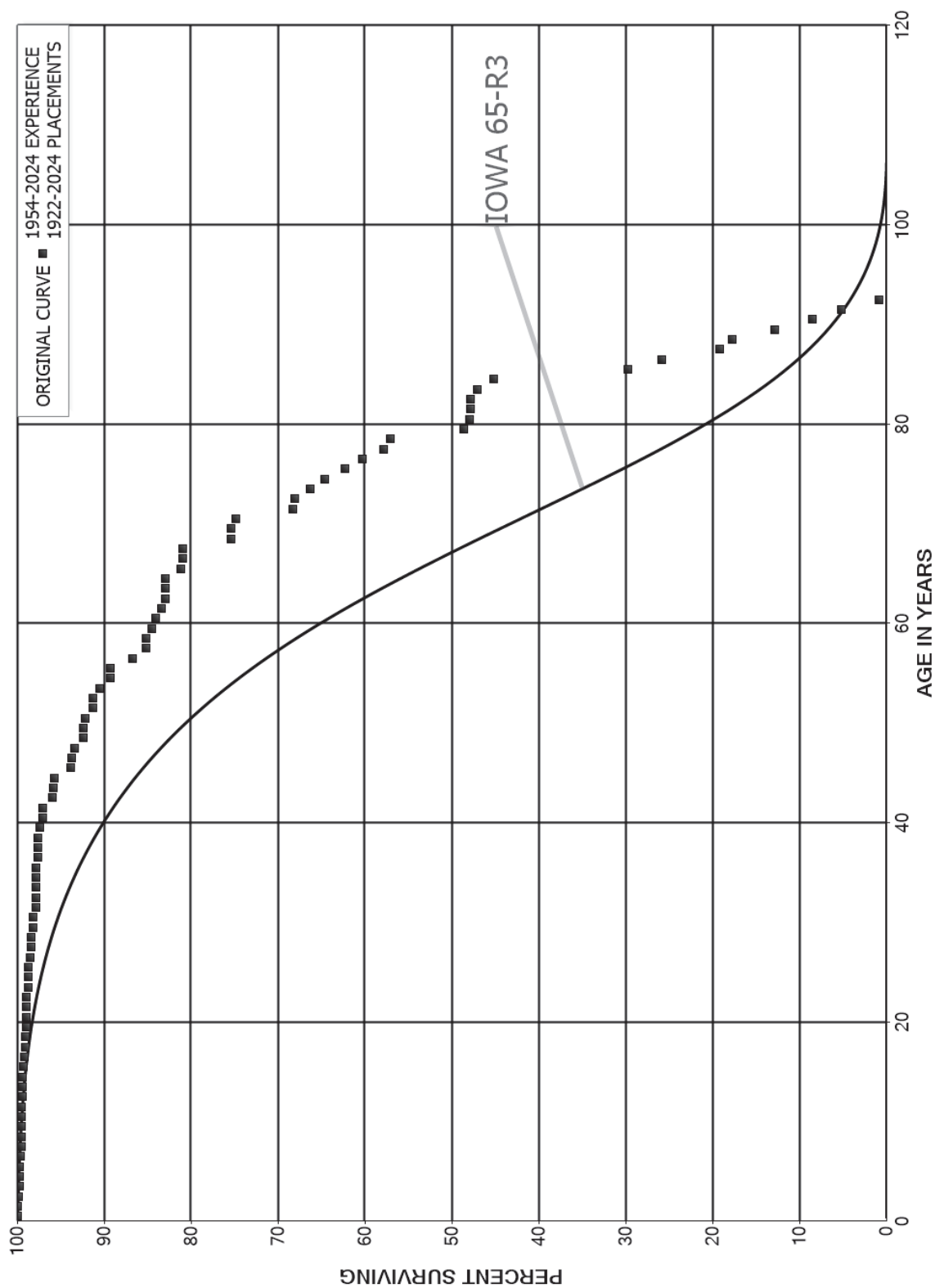
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,522,358	240,024	0.0319	0.9681	67.88
40.5	7,269,229	1,293,711	0.1780	0.8220	65.72
41.5	5,971,184	947,553	0.1587	0.8413	54.02
42.5	4,827,808	494,334	0.1024	0.8976	45.45
43.5	4,306,869	361,410	0.0839	0.9161	40.80
44.5	3,941,531	640,134	0.1624	0.8376	37.37
45.5	3,297,809	576,882	0.1749	0.8251	31.30
46.5	2,680,515	259,217	0.0967	0.9033	25.83
47.5	2,102,249	82,859	0.0394	0.9606	23.33
48.5	2,003,358	603,602	0.3013	0.6987	22.41
49.5	1,269,317	145,637	0.1147	0.8853	15.66
50.5	1,123,681	562,277	0.5004	0.4996	13.86
51.5	560,969	284,882	0.5078	0.4922	6.93
52.5	276,087	149,801	0.5426	0.4574	3.41
53.5	126,287	18,530	0.1467	0.8533	1.56
54.5	107,756	56,048	0.5201	0.4799	1.33
55.5	50,492	34,459	0.6825	0.3175	0.64
56.5	16,033		0.0000	1.0000	0.20
57.5	14,792	428	0.0290	0.9710	0.20
58.5	14,363	1,634	0.1138	0.8862	0.20
59.5	4,467	2,577	0.5769	0.4231	0.17
60.5	1,890	444	0.2349	0.7651	0.07
61.5	1,446	834	0.5765	0.4235	0.06
62.5	612	258	0.4210	0.5790	0.02
63.5	355		0.0000	1.0000	0.01
64.5	355	64	0.1794	0.8206	0.01
65.5	291		0.0000	1.0000	0.01
66.5	291		0.0000	1.0000	0.01
67.5	291	1	0.0035	0.9965	0.01
68.5	290		0.0000	1.0000	0.01
69.5	290		0.0000	1.0000	0.01
70.5	290		0.0000	1.0000	0.01
71.5	290		0.0000	1.0000	0.01
72.5	290		0.0000	1.0000	0.01
73.5	290		0.0000	1.0000	0.01
74.5	290		0.0000	1.0000	0.01
75.5	290		0.0000	1.0000	0.01
76.5	290		0.0000	1.0000	0.01
77.5	290		0.0000	1.0000	0.01
78.5	290		0.0000	1.0000	0.01
79.5	290		0.0000	1.0000	0.01
80.5					0.01

KENTUCKY POWER COMPANY  
ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1922-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	191,745,409	8,123	0.0000	1.0000	100.00
0.5	175,967,240	144,328	0.0008	0.9992	100.00
1.5	172,288,990	227,727	0.0013	0.9987	99.91
2.5	168,016,814	35,675	0.0002	0.9998	99.78
3.5	158,338,486	4,163	0.0000	1.0000	99.76
4.5	150,676,857	18,171	0.0001	0.9999	99.76
5.5	141,655,219	192,393	0.0014	0.9986	99.75
6.5	139,984,056	123,606	0.0009	0.9991	99.61
7.5	138,382,796	12,785	0.0001	0.9999	99.52
8.5	137,555,938	6,763	0.0000	1.0000	99.51
9.5	135,847,971	9,973	0.0001	0.9999	99.51
10.5	122,235,219	32,937	0.0003	0.9997	99.50
11.5	120,842,848	31,849	0.0003	0.9997	99.47
12.5	114,878,469	71,643	0.0006	0.9994	99.45
13.5	110,580,631	18,828	0.0002	0.9998	99.39
14.5	109,643,759	86,531	0.0008	0.9992	99.37
15.5	108,870,498	165,219	0.0015	0.9985	99.29
16.5	100,560,429	55,326	0.0006	0.9994	99.14
17.5	100,126,821	63,637	0.0006	0.9994	99.09
18.5	99,841,077	17,078	0.0002	0.9998	99.02
19.5	98,966,801	24,764	0.0003	0.9997	99.01
20.5	98,702,285	29,759	0.0003	0.9997	98.98
21.5	98,020,669	10,262	0.0001	0.9999	98.95
22.5	97,589,520	160,831	0.0016	0.9984	98.94
23.5	96,448,010	65,402	0.0007	0.9993	98.78
24.5	94,490,629	37,910	0.0004	0.9996	98.71
25.5	82,468,630	102,303	0.0012	0.9988	98.67
26.5	79,623,343	85,000	0.0011	0.9989	98.55
27.5	78,856,863	38,173	0.0005	0.9995	98.44
28.5	77,484,174	184,653	0.0024	0.9976	98.40
29.5	76,276,278	12,423	0.0002	0.9998	98.16
30.5	73,018,135	237,942	0.0033	0.9967	98.15
31.5	71,148,755	11,849	0.0002	0.9998	97.83
32.5	69,138,327	10,299	0.0001	0.9999	97.81
33.5	68,533,490	2,581	0.0000	1.0000	97.79
34.5	68,185,930	3,348	0.0000	1.0000	97.79
35.5	67,911,351	108,339	0.0016	0.9984	97.79
36.5	67,620,092	2,917	0.0000	1.0000	97.63
37.5	67,504,453	8,584	0.0001	0.9999	97.63
38.5	66,672,082	160,046	0.0024	0.9976	97.61

KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,693,106	67,154	0.0032	0.9968	97.38
40.5	20,529,507	7,033	0.0003	0.9997	97.06
41.5	20,487,344	225,614	0.0110	0.9890	97.03
42.5	18,586,179	25,975	0.0014	0.9986	95.96
43.5	17,881,705	17,156	0.0010	0.9990	95.83
44.5	17,614,182	352,124	0.0200	0.9800	95.74
45.5	17,202,732	26,512	0.0015	0.9985	93.82
46.5	15,319,256	42,324	0.0028	0.9972	93.68
47.5	14,767,227	156,179	0.0106	0.9894	93.42
48.5	14,519,005	5,929	0.0004	0.9996	92.43
49.5	14,354,847	27,702	0.0019	0.9981	92.39
50.5	14,310,590	136,007	0.0095	0.9905	92.21
51.5	14,142,499	7,981	0.0006	0.9994	91.34
52.5	13,991,088	127,593	0.0091	0.9909	91.29
53.5	12,875,220	165,103	0.0128	0.9872	90.45
54.5	4,676,772	1,450	0.0003	0.9997	89.29
55.5	4,490,604	125,214	0.0279	0.9721	89.27
56.5	3,197,875	57,839	0.0181	0.9819	86.78
57.5	2,645,549	1,863	0.0007	0.9993	85.21
58.5	2,599,648	20,147	0.0077	0.9923	85.15
59.5	2,096,763	9,133	0.0044	0.9956	84.49
60.5	2,050,703	17,342	0.0085	0.9915	84.12
61.5	1,519,372	8,564	0.0056	0.9944	83.41
62.5	1,432,055		0.0000	1.0000	82.94
63.5	1,424,559		0.0000	1.0000	82.94
64.5	1,403,872	29,724	0.0212	0.9788	82.94
65.5	1,179,817	2,577	0.0022	0.9978	81.18
66.5	830,477		0.0000	1.0000	81.00
67.5	824,408	56,786	0.0689	0.9311	81.00
68.5	757,031		0.0000	1.0000	75.42
69.5	753,197	5,908	0.0078	0.9922	75.42
70.5	669,771	58,497	0.0873	0.9127	74.83
71.5	590,013	1,971	0.0033	0.9967	68.30
72.5	578,921	14,932	0.0258	0.9742	68.07
73.5	550,569	14,017	0.0255	0.9745	66.31
74.5	533,749	19,359	0.0363	0.9637	64.63
75.5	513,832	16,876	0.0328	0.9672	62.28
76.5	496,826	19,823	0.0399	0.9601	60.24
77.5	476,901	6,482	0.0136	0.9864	57.83
78.5	464,491	68,608	0.1477	0.8523	57.05



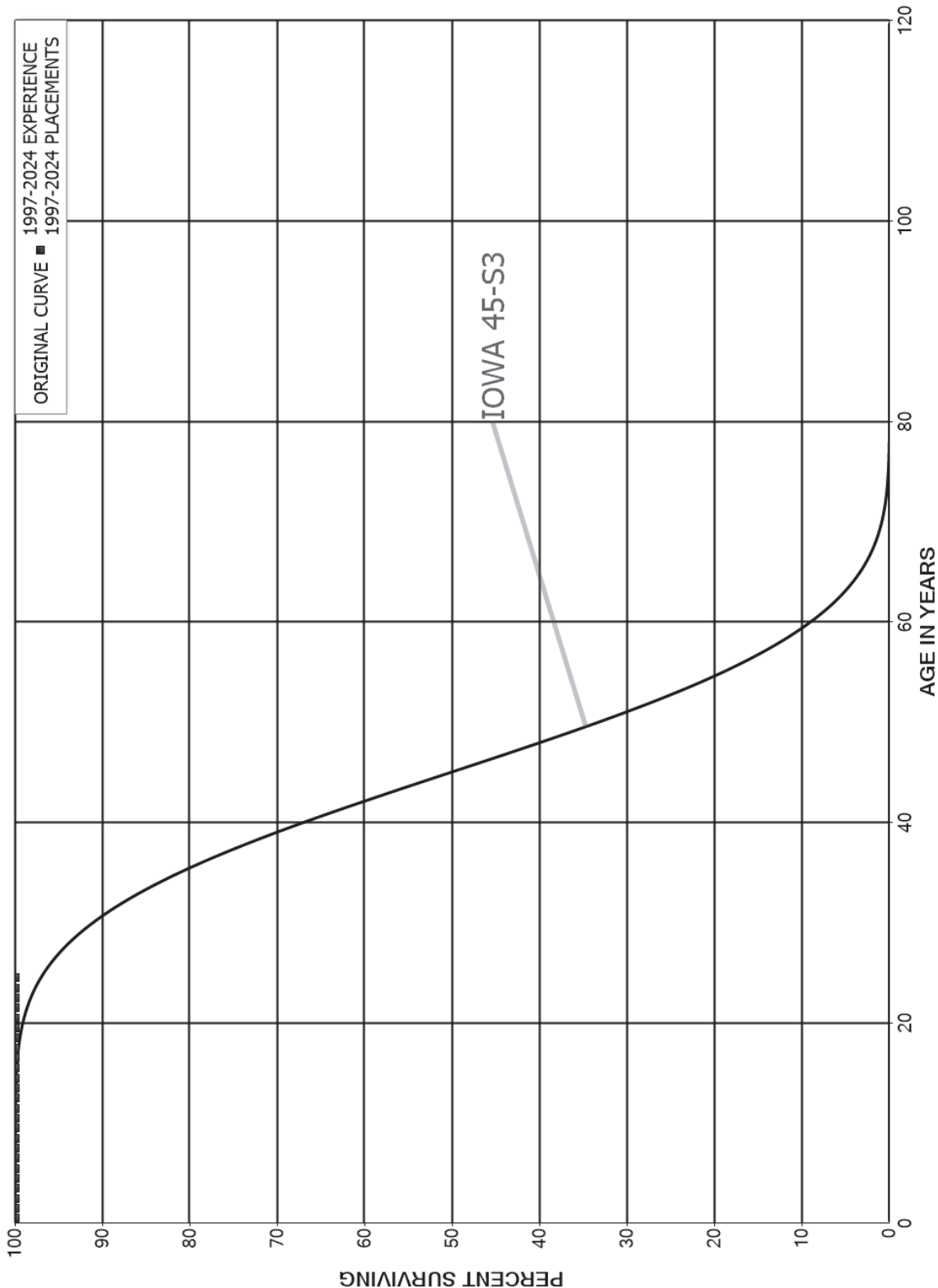
KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	394,716	5,755	0.0146	0.9854	48.62
80.5	384,327	234	0.0006	0.9994	47.91
81.5	383,808		0.0000	1.0000	47.88
82.5	103,911	1,816	0.0175	0.9825	47.88
83.5	100,907	4,116	0.0408	0.9592	47.05
84.5	27,044	9,262	0.3425	0.6575	45.13
85.5	17,307	2,228	0.1287	0.8713	29.67
86.5	15,012	3,906	0.2602	0.7398	25.85
87.5	10,423	749	0.0719	0.9281	19.13
88.5	9,172	2,554	0.2785	0.7215	17.75
89.5	6,256	2,083	0.3330	0.6670	12.81
90.5	4,143	1,634	0.3943	0.6057	8.54
91.5	2,495	2,093	0.8389	0.1611	5.17
92.5	383		0.0000	1.0000	0.83
93.5	364		0.0000	1.0000	0.83
94.5	324		0.0000	1.0000	0.83
95.5	187		0.0000	1.0000	0.83
96.5	157		0.0000	1.0000	0.83
97.5	115	0	0.0003	0.9997	0.83
98.5	41		0.0000	1.0000	0.83
99.5	25		0.0000	1.0000	0.83
100.5	22	0	0.0009	0.9991	0.83
101.5	12		0.0000	1.0000	0.83
102.5					0.83

KENTUCKY POWER COMPANY  
ACCOUNT 357.00 UNDERGROUND CONDUIT  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 357.00 UNDERGROUND CONDUIT

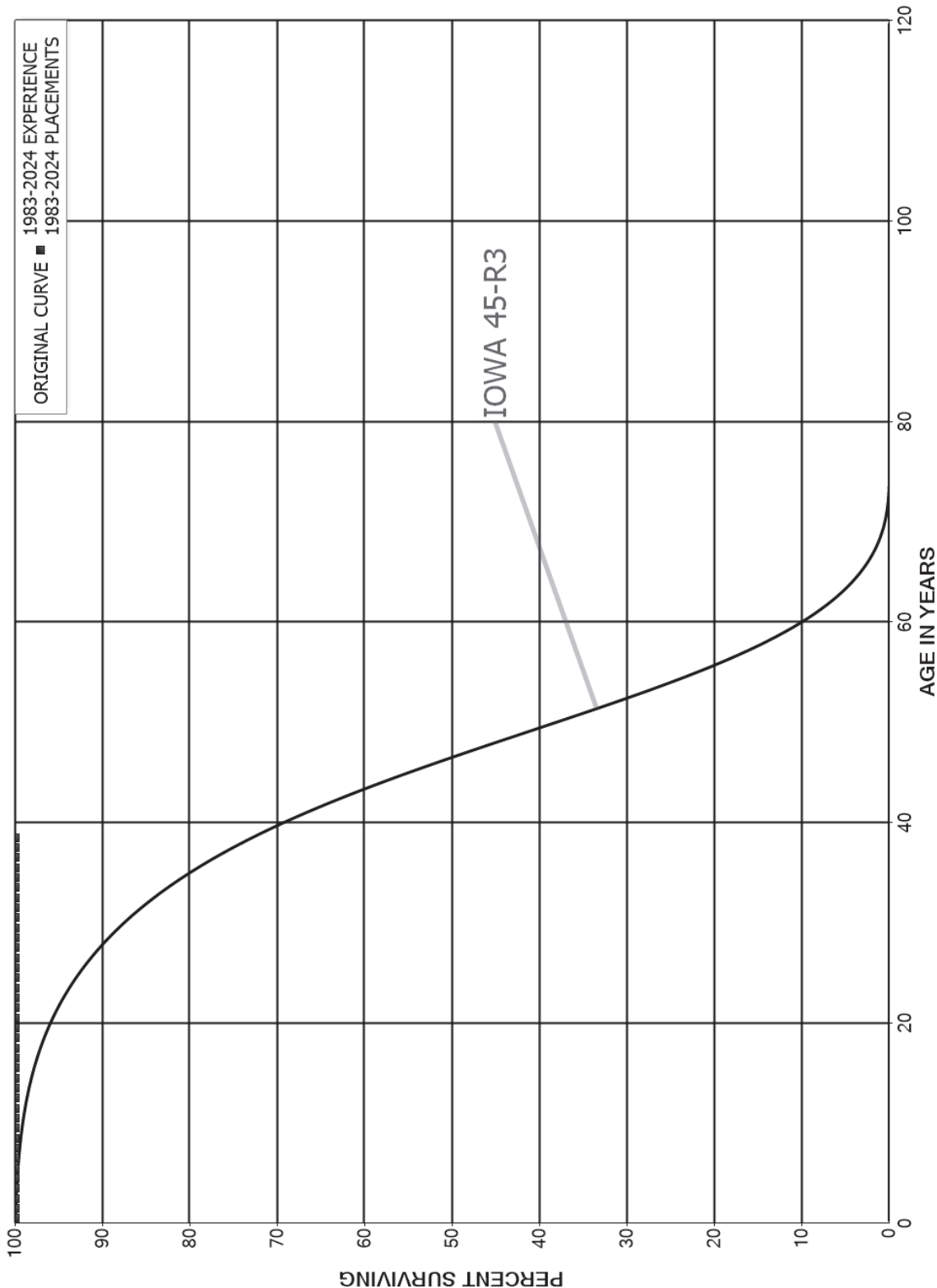
ORIGINAL LIFE TABLE

PLACEMENT BAND 1997-2024

EXPERIENCE BAND 1997-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,861,948		0.0000	1.0000	100.00
0.5	5,646,683		0.0000	1.0000	100.00
1.5	5,173,402		0.0000	1.0000	100.00
2.5	510,952		0.0000	1.0000	100.00
3.5	510,952		0.0000	1.0000	100.00
4.5	313,849		0.0000	1.0000	100.00
5.5	11,590		0.0000	1.0000	100.00
6.5	11,590		0.0000	1.0000	100.00
7.5	11,590		0.0000	1.0000	100.00
8.5	11,590		0.0000	1.0000	100.00
9.5	11,590		0.0000	1.0000	100.00
10.5	11,590		0.0000	1.0000	100.00
11.5	11,590		0.0000	1.0000	100.00
12.5	11,590		0.0000	1.0000	100.00
13.5	11,590		0.0000	1.0000	100.00
14.5	11,590		0.0000	1.0000	100.00
15.5	11,590		0.0000	1.0000	100.00
16.5	11,590		0.0000	1.0000	100.00
17.5	11,590		0.0000	1.0000	100.00
18.5	11,590		0.0000	1.0000	100.00
19.5	11,590		0.0000	1.0000	100.00
20.5	11,590		0.0000	1.0000	100.00
21.5	11,590		0.0000	1.0000	100.00
22.5	11,590		0.0000	1.0000	100.00
23.5	11,590		0.0000	1.0000	100.00
24.5	11,590		0.0000	1.0000	100.00
25.5	11,590		0.0000	1.0000	100.00
26.5	11,590		0.0000	1.0000	100.00
27.5					100.00

KENTUCKY POWER COMPANY  
ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2024

EXPERIENCE BAND 1983-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	561,965		0.0000	1.0000	100.00
0.5	543,757		0.0000	1.0000	100.00
1.5	497,623		0.0000	1.0000	100.00
2.5	497,623		0.0000	1.0000	100.00
3.5	381,454		0.0000	1.0000	100.00
4.5	379,101		0.0000	1.0000	100.00
5.5	106,066		0.0000	1.0000	100.00
6.5	106,066		0.0000	1.0000	100.00
7.5	106,066		0.0000	1.0000	100.00
8.5	106,066		0.0000	1.0000	100.00
9.5	106,066		0.0000	1.0000	100.00
10.5	106,066		0.0000	1.0000	100.00
11.5	106,066		0.0000	1.0000	100.00
12.5	106,066		0.0000	1.0000	100.00
13.5	106,066		0.0000	1.0000	100.00
14.5	106,066		0.0000	1.0000	100.00
15.5	106,066		0.0000	1.0000	100.00
16.5	106,066		0.0000	1.0000	100.00
17.5	106,066		0.0000	1.0000	100.00
18.5	106,066		0.0000	1.0000	100.00
19.5	106,066		0.0000	1.0000	100.00
20.5	106,066		0.0000	1.0000	100.00
21.5	106,066		0.0000	1.0000	100.00
22.5	106,066		0.0000	1.0000	100.00
23.5	106,066		0.0000	1.0000	100.00
24.5	106,066		0.0000	1.0000	100.00
25.5	106,066		0.0000	1.0000	100.00
26.5	106,066		0.0000	1.0000	100.00
27.5	106,066		0.0000	1.0000	100.00
28.5	106,066		0.0000	1.0000	100.00
29.5	106,066		0.0000	1.0000	100.00
30.5	106,066		0.0000	1.0000	100.00
31.5	106,066		0.0000	1.0000	100.00
32.5	106,066		0.0000	1.0000	100.00
33.5	106,066		0.0000	1.0000	100.00
34.5	106,066		0.0000	1.0000	100.00
35.5	106,066		0.0000	1.0000	100.00
36.5	106,066		0.0000	1.0000	100.00
37.5	106,066		0.0000	1.0000	100.00
38.5	106,066		0.0000	1.0000	100.00

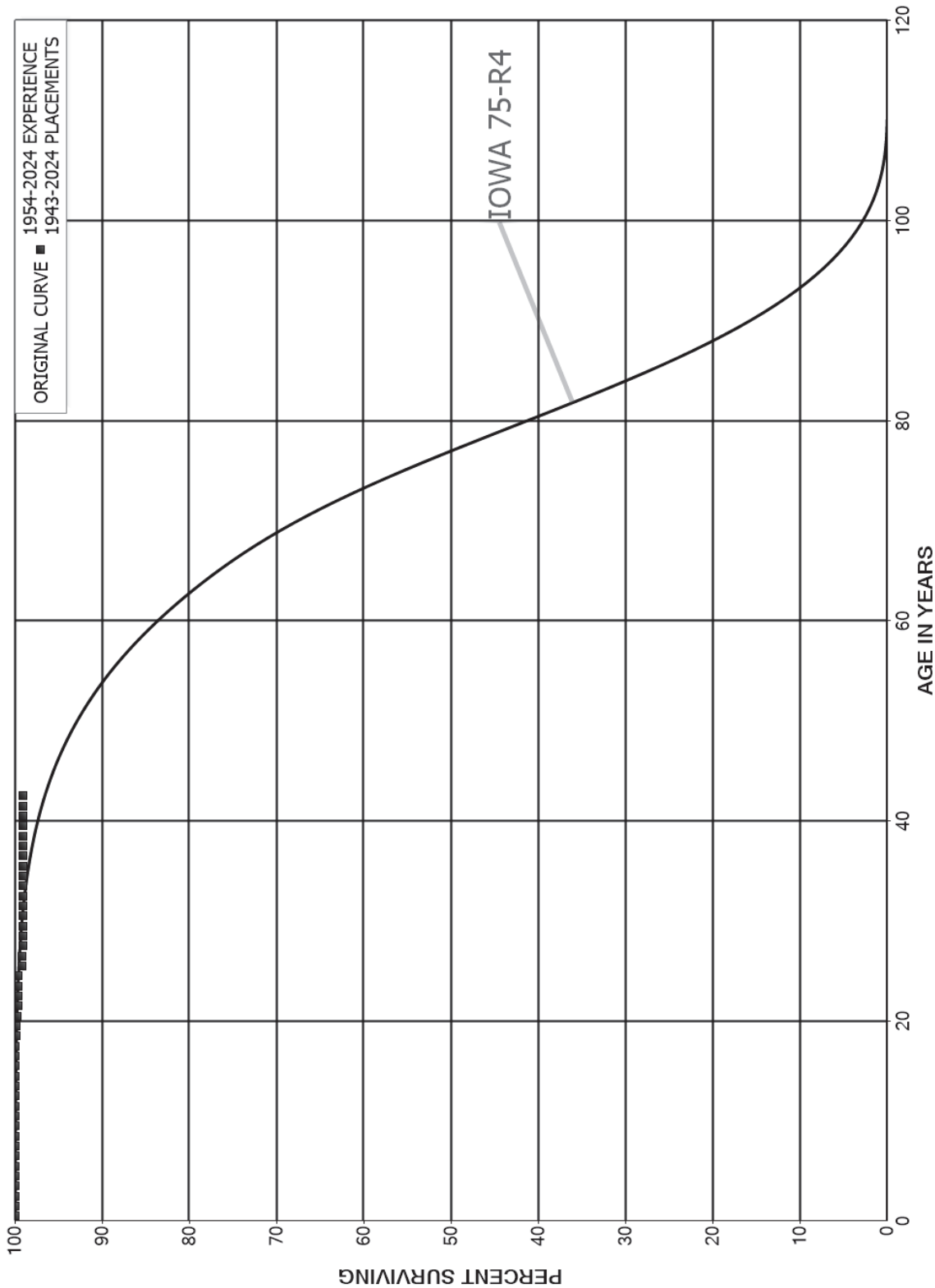
KENTUCKY POWER COMPANY

ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1983-2024			EXPERIENCE BAND 1983-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	106,066		0.0000	1.0000	100.00
40.5	106,066		0.0000	1.0000	100.00
41.5					100.00

KENTUCKY POWER COMPANY  
ACCOUNT 360.10 LAND RIGHTS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 360.10 LAND RIGHTS

ORIGINAL LIFE TABLE

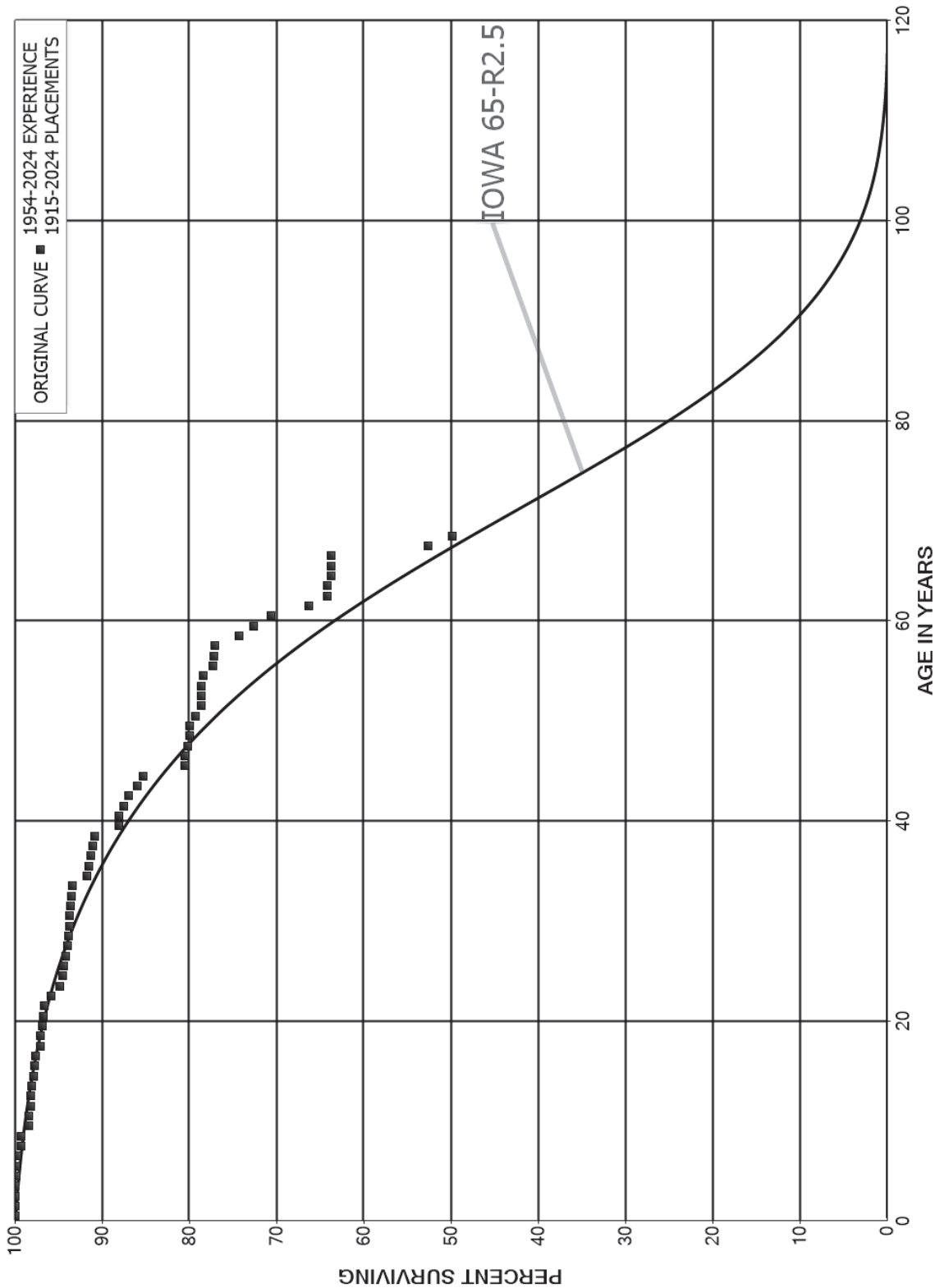
PLACEMENT BAND 1943-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,511,024		0.0000	1.0000	100.00
0.5	6,366,736		0.0000	1.0000	100.00
1.5	6,244,246		0.0000	1.0000	100.00
2.5	5,885,362		0.0000	1.0000	100.00
3.5	5,885,362		0.0000	1.0000	100.00
4.5	5,700,055		0.0000	1.0000	100.00
5.5	5,557,688		0.0000	1.0000	100.00
6.5	5,345,556		0.0000	1.0000	100.00
7.5	5,345,556		0.0000	1.0000	100.00
8.5	5,345,556		0.0000	1.0000	100.00
9.5	5,345,556		0.0000	1.0000	100.00
10.5	5,378,849		0.0000	1.0000	100.00
11.5	5,232,833		0.0000	1.0000	100.00
12.5	5,071,215		0.0000	1.0000	100.00
13.5	4,908,446		0.0000	1.0000	100.00
14.5	4,747,467		0.0000	1.0000	100.00
15.5	4,544,724		0.0000	1.0000	100.00
16.5	4,395,670	301	0.0001	0.9999	100.00
17.5	4,211,627	5,771	0.0014	0.9986	99.99
18.5	4,031,034	2,701	0.0007	0.9993	99.86
19.5	3,910,377	2,326	0.0006	0.9994	99.79
20.5	3,807,276	3,825	0.0010	0.9990	99.73
21.5	3,614,470	943	0.0003	0.9997	99.63
22.5	3,482,219	325	0.0001	0.9999	99.60
23.5	3,375,363	623	0.0002	0.9998	99.59
24.5	3,059,724	13,964	0.0046	0.9954	99.58
25.5	3,042,083		0.0000	1.0000	99.12
26.5	2,933,440	1,966	0.0007	0.9993	99.12
27.5	2,711,934	364	0.0001	0.9999	99.06
28.5	2,658,223		0.0000	1.0000	99.04
29.5	2,551,822		0.0000	1.0000	99.04
30.5	2,537,799	156	0.0001	0.9999	99.04
31.5	2,488,515		0.0000	1.0000	99.04
32.5	2,393,751		0.0000	1.0000	99.04
33.5	2,317,597		0.0000	1.0000	99.04
34.5	2,262,759	28	0.0000	1.0000	99.04
35.5	2,231,530		0.0000	1.0000	99.03
36.5	2,205,150		0.0000	1.0000	99.03
37.5	2,186,134		0.0000	1.0000	99.03
38.5	2,138,788		0.0000	1.0000	99.03



KENTUCKY POWER COMPANY  
ACCOUNT 360.10 LAND RIGHTS  
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,118,069		0.0000	1.0000	99.03
40.5	2,092,135		0.0000	1.0000	99.03
41.5	2,025,274		0.0000	1.0000	99.03
42.5	1,976,332		0.0000	1.0000	99.03
43.5	1,937,824		0.0000	1.0000	99.03
44.5	1,913,234		0.0000	1.0000	99.03
45.5					99.03

KENTUCKY POWER COMPANY  
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1915-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,544,754	102	0.0000	1.0000	100.00
0.5	12,632,240	2,131	0.0002	0.9998	100.00
1.5	9,715,067	1,155	0.0001	0.9999	99.98
2.5	9,679,321	3,555	0.0004	0.9996	99.97
3.5	7,439,527	3,444	0.0005	0.9995	99.93
4.5	7,126,295	2,168	0.0003	0.9997	99.89
5.5	5,479,407	9,431	0.0017	0.9983	99.86
6.5	4,848,084	17,684	0.0036	0.9964	99.69
7.5	4,659,783	1,158	0.0002	0.9998	99.32
8.5	4,536,296	40,345	0.0089	0.9911	99.30
9.5	4,509,004	1,714	0.0004	0.9996	98.41
10.5	4,498,311	7,323	0.0016	0.9984	98.38
11.5	4,492,401	1,008	0.0002	0.9998	98.22
12.5	4,495,033	6,047	0.0013	0.9987	98.19
13.5	4,398,145	9,663	0.0022	0.9978	98.06
14.5	4,387,822	5,562	0.0013	0.9987	97.85
15.5	4,400,099	6,318	0.0014	0.9986	97.72
16.5	4,257,295	20,640	0.0048	0.9952	97.58
17.5	4,239,730	377	0.0001	0.9999	97.11
18.5	4,239,353	12,458	0.0029	0.9971	97.10
19.5	4,218,260	2,135	0.0005	0.9995	96.82
20.5	4,216,998	6,776	0.0016	0.9984	96.77
21.5	3,814,438	29,914	0.0078	0.9922	96.61
22.5	3,746,801	37,702	0.0101	0.9899	95.85
23.5	3,702,246	13,816	0.0037	0.9963	94.89
24.5	3,591,202	4,831	0.0013	0.9987	94.53
25.5	3,202,389	9,658	0.0030	0.9970	94.41
26.5	3,168,181	5,631	0.0018	0.9982	94.12
27.5	3,124,029	3,532	0.0011	0.9989	93.96
28.5	3,087,619	2,600	0.0008	0.9992	93.85
29.5	2,503,958	726	0.0003	0.9997	93.77
30.5	2,406,205	2,506	0.0010	0.9990	93.74
31.5	2,169,469	2,159	0.0010	0.9990	93.65
32.5	2,055,291	3,556	0.0017	0.9983	93.55
33.5	1,714,555	31,461	0.0183	0.9817	93.39
34.5	1,651,555	3,162	0.0019	0.9981	91.68
35.5	1,615,897	3,133	0.0019	0.9981	91.50
36.5	1,577,130	4,615	0.0029	0.9971	91.32
37.5	1,473,311	4,270	0.0029	0.9971	91.06
38.5	1,321,954	39,273	0.0297	0.9703	90.79

KENTUCKY POWER COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1915-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,163,598	200	0.0002	0.9998	88.10
40.5	1,152,895	6,881	0.0060	0.9940	88.08
41.5	1,139,056	7,122	0.0063	0.9937	87.55
42.5	1,070,036	13,343	0.0125	0.9875	87.01
43.5	963,953	7,214	0.0075	0.9925	85.92
44.5	621,394	34,726	0.0559	0.9441	85.28
45.5	580,718		0.0000	1.0000	80.51
46.5	543,588	1,932	0.0036	0.9964	80.51
47.5	462,681	1,362	0.0029	0.9971	80.23
48.5	455,522	225	0.0005	0.9995	79.99
49.5	383,739	2,991	0.0078	0.9922	79.95
50.5	319,110	3,077	0.0096	0.9904	79.33
51.5	277,809		0.0000	1.0000	78.56
52.5	242,742		0.0000	1.0000	78.56
53.5	182,566	370	0.0020	0.9980	78.56
54.5	168,938	2,380	0.0141	0.9859	78.40
55.5	159,588	261	0.0016	0.9984	77.30
56.5	138,534	111	0.0008	0.9992	77.17
57.5	124,517	4,579	0.0368	0.9632	77.11
58.5	96,015	2,149	0.0224	0.9776	74.28
59.5	92,054	2,540	0.0276	0.9724	72.61
60.5	89,019	5,484	0.0616	0.9384	70.61
61.5	78,333	2,453	0.0313	0.9687	66.26
62.5	75,690		0.0000	1.0000	64.19
63.5	74,105	540	0.0073	0.9927	64.19
64.5	73,274		0.0000	1.0000	63.72
65.5	73,081		0.0000	1.0000	63.72
66.5	73,081	12,737	0.1743	0.8257	63.72
67.5	54,398	2,866	0.0527	0.9473	52.61
68.5	46,903		0.0000	1.0000	49.84
69.5	46,202		0.0000	1.0000	49.84
70.5	41,296		0.0000	1.0000	49.84
71.5	33,112		0.0000	1.0000	49.84
72.5	33,035	189	0.0057	0.9943	49.84
73.5	32,846		0.0000	1.0000	49.56
74.5	29,725		0.0000	1.0000	49.56
75.5	25,863		0.0000	1.0000	49.56
76.5	20,689	140	0.0068	0.9932	49.56
77.5	19,642	269	0.0137	0.9863	49.22
78.5	19,331		0.0000	1.0000	48.55

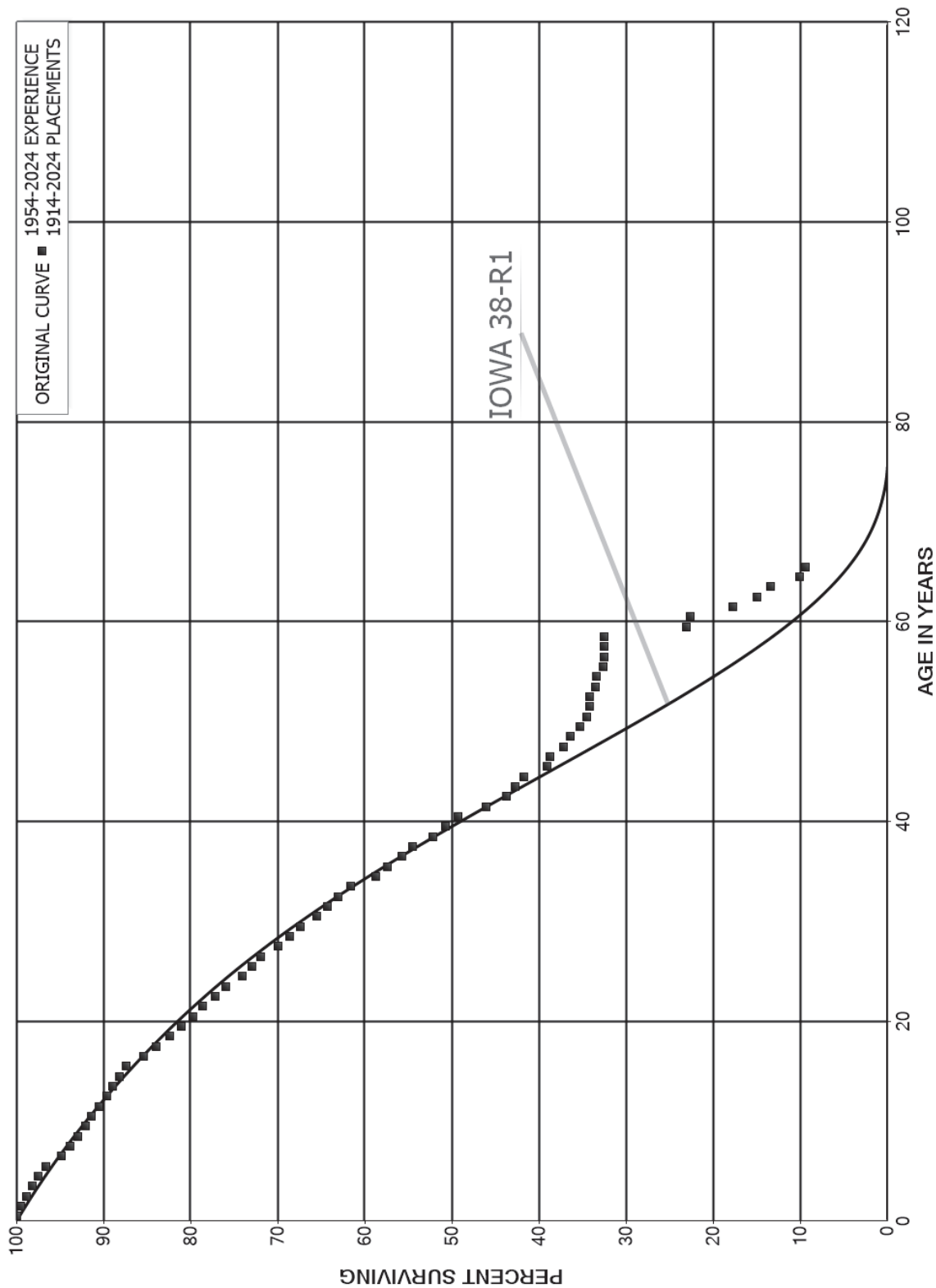
KENTUCKY POWER COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1915-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	18,574		0.0000	1.0000	48.55
80.5	18,574		0.0000	1.0000	48.55
81.5	16,902		0.0000	1.0000	48.55
82.5	15,925		0.0000	1.0000	48.55
83.5	15,925		0.0000	1.0000	48.55
84.5	12,655		0.0000	1.0000	48.55
85.5	12,655		0.0000	1.0000	48.55
86.5					48.55

KENTUCKY POWER COMPANY  
ACCOUNT 362.00 STATION EQUIPMENT  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1914-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	199,322,356	102,925	0.0005	0.9995	100.00
0.5	178,545,893	835,075	0.0047	0.9953	99.95
1.5	171,496,330	1,123,097	0.0065	0.9935	99.48
2.5	166,372,693	1,060,417	0.0064	0.9936	98.83
3.5	154,800,703	1,115,333	0.0072	0.9928	98.20
4.5	149,891,005	1,348,512	0.0090	0.9910	97.49
5.5	131,082,539	2,409,423	0.0184	0.9816	96.61
6.5	121,707,515	1,230,287	0.0101	0.9899	94.84
7.5	109,936,395	1,140,692	0.0104	0.9896	93.88
8.5	104,693,832	957,078	0.0091	0.9909	92.91
9.5	102,160,583	682,920	0.0067	0.9933	92.06
10.5	93,837,659	980,399	0.0104	0.9896	91.44
11.5	85,465,888	792,031	0.0093	0.9907	90.49
12.5	76,435,860	587,802	0.0077	0.9923	89.65
13.5	68,274,852	586,849	0.0086	0.9914	88.96
14.5	66,396,966	639,668	0.0096	0.9904	88.19
15.5	60,650,535	1,332,227	0.0220	0.9780	87.34
16.5	50,526,842	890,057	0.0176	0.9824	85.43
17.5	47,021,504	846,808	0.0180	0.9820	83.92
18.5	43,685,922	718,210	0.0164	0.9836	82.41
19.5	40,857,091	694,150	0.0170	0.9830	81.05
20.5	39,425,191	543,614	0.0138	0.9862	79.68
21.5	38,182,185	684,953	0.0179	0.9821	78.58
22.5	36,954,111	600,579	0.0163	0.9837	77.17
23.5	34,711,967	837,931	0.0241	0.9759	75.91
24.5	32,372,225	495,948	0.0153	0.9847	74.08
25.5	31,248,673	437,128	0.0140	0.9860	72.95
26.5	30,060,638	801,723	0.0267	0.9733	71.93
27.5	27,724,020	560,196	0.0202	0.9798	70.01
28.5	25,552,409	461,671	0.0181	0.9819	68.59
29.5	21,564,220	579,687	0.0269	0.9731	67.35
30.5	19,968,757	376,380	0.0188	0.9812	65.54
31.5	17,273,581	336,299	0.0195	0.9805	64.31
32.5	16,070,702	369,236	0.0230	0.9770	63.06
33.5	14,491,495	688,225	0.0475	0.9525	61.61
34.5	13,493,275	291,715	0.0216	0.9784	58.68
35.5	12,822,594	383,340	0.0299	0.9701	57.41
36.5	12,192,978	257,453	0.0211	0.9789	55.70
37.5	10,768,990	455,252	0.0423	0.9577	54.52
38.5	9,196,636	269,743	0.0293	0.9707	52.22

KENTUCKY POWER COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

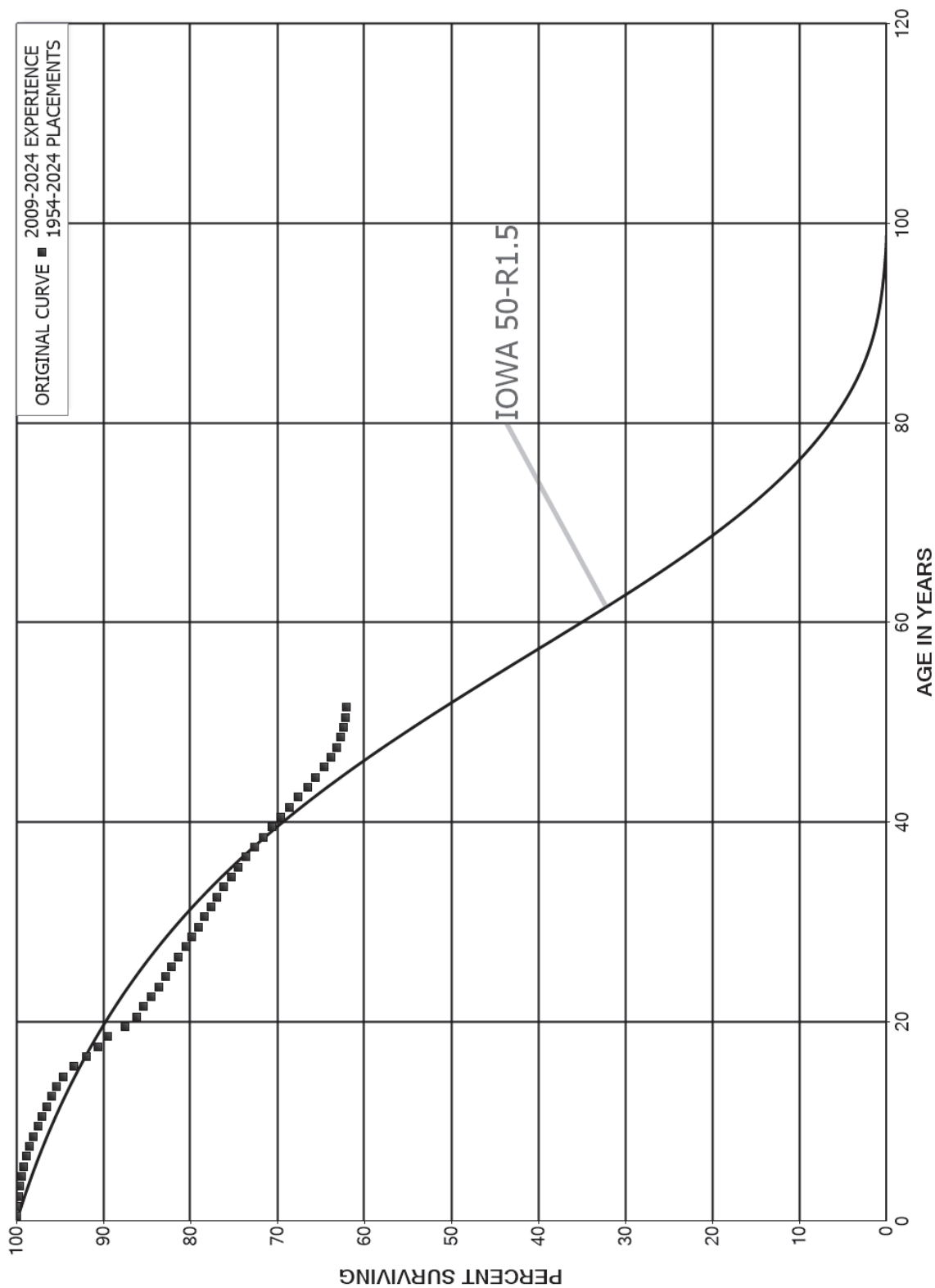
PLACEMENT BAND 1914-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,350,292	224,805	0.0269	0.9731	50.68
40.5	7,495,188	498,128	0.0665	0.9335	49.32
41.5	6,810,596	347,533	0.0510	0.9490	46.04
42.5	5,591,608	120,120	0.0215	0.9785	43.69
43.5	5,106,817	128,819	0.0252	0.9748	42.75
44.5	3,545,123	224,324	0.0633	0.9367	41.68
45.5	3,008,501	24,150	0.0080	0.9920	39.04
46.5	2,280,094	90,166	0.0395	0.9605	38.73
47.5	1,818,153	36,507	0.0201	0.9799	37.19
48.5	1,719,171	52,808	0.0307	0.9693	36.45
49.5	1,614,614	38,808	0.0240	0.9760	35.33
50.5	1,421,608	11,943	0.0084	0.9916	34.48
51.5	1,090,666		0.0000	1.0000	34.19
52.5	693,469	14,446	0.0208	0.9792	34.19
53.5	541,604	906	0.0017	0.9983	33.48
54.5	408,883	10,382	0.0254	0.9746	33.42
55.5	378,227	379	0.0010	0.9990	32.57
56.5	305,276		0.0000	1.0000	32.54
57.5	196,637		0.0000	1.0000	32.54
58.5	143,051	41,699	0.2915	0.7085	32.54
59.5	100,365	2,128	0.0212	0.9788	23.05
60.5	93,672	20,121	0.2148	0.7852	22.57
61.5	48,298	7,606	0.1575	0.8425	17.72
62.5	30,428	3,014	0.0991	0.9009	14.93
63.5	17,344	4,350	0.2508	0.7492	13.45
64.5	12,994	868	0.0668	0.9332	10.08
65.5	12,126		0.0000	1.0000	9.40
66.5	12,126		0.0000	1.0000	9.40
67.5					9.40



KENTUCKY POWER COMPANY  
ACCOUNT 364.00 POLES AND FIXTURES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 364.00 POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	205,058,783		0.0000	1.0000	100.00
0.5	198,397,258	131,163	0.0007	0.9993	100.00
1.5	177,803,194	286,688	0.0016	0.9984	99.93
2.5	163,703,103	293,675	0.0018	0.9982	99.77
3.5	146,875,921	294,365	0.0020	0.9980	99.59
4.5	126,014,631	298,859	0.0024	0.9976	99.39
5.5	114,895,443	341,183	0.0030	0.9970	99.16
6.5	109,253,639	428,965	0.0039	0.9961	98.86
7.5	106,744,601	469,486	0.0044	0.9956	98.48
8.5	106,820,672	533,357	0.0050	0.9950	98.04
9.5	103,672,759	542,684	0.0052	0.9948	97.55
10.5	98,484,393	528,174	0.0054	0.9946	97.04
11.5	92,956,829	527,119	0.0057	0.9943	96.52
12.5	96,153,964	623,093	0.0065	0.9935	95.97
13.5	94,550,527	729,294	0.0077	0.9923	95.35
14.5	93,546,116	1,261,808	0.0135	0.9865	94.62
15.5	87,428,974	1,279,362	0.0146	0.9854	93.34
16.5	84,389,060	1,294,636	0.0153	0.9847	91.98
17.5	81,600,686	942,018	0.0115	0.9885	90.56
18.5	79,920,725	1,804,888	0.0226	0.9774	89.52
19.5	74,803,943	1,148,824	0.0154	0.9846	87.50
20.5	72,523,161	660,339	0.0091	0.9909	86.15
21.5	71,198,678	732,623	0.0103	0.9897	85.37
22.5	70,483,815	756,539	0.0107	0.9893	84.49
23.5	69,525,913	639,205	0.0092	0.9908	83.58
24.5	64,796,908	518,453	0.0080	0.9920	82.82
25.5	62,360,570	616,268	0.0099	0.9901	82.15
26.5	62,471,830	604,351	0.0097	0.9903	81.34
27.5	63,706,467	553,267	0.0087	0.9913	80.55
28.5	59,567,445	557,740	0.0094	0.9906	79.85
29.5	56,756,947	544,815	0.0096	0.9904	79.11
30.5	52,947,178	489,808	0.0093	0.9907	78.35
31.5	49,625,435	452,636	0.0091	0.9909	77.62
32.5	45,507,033	450,636	0.0099	0.9901	76.91
33.5	41,351,050	465,695	0.0113	0.9887	76.15
34.5	37,944,737	417,246	0.0110	0.9890	75.30
35.5	36,574,411	436,108	0.0119	0.9881	74.47
36.5	33,613,245	429,572	0.0128	0.9872	73.58
37.5	30,115,530	409,891	0.0136	0.9864	72.64
38.5	26,195,146	361,826	0.0138	0.9862	71.65

KENTUCKY POWER COMPANY

ACCOUNT 364.00 POLES AND FIXTURES

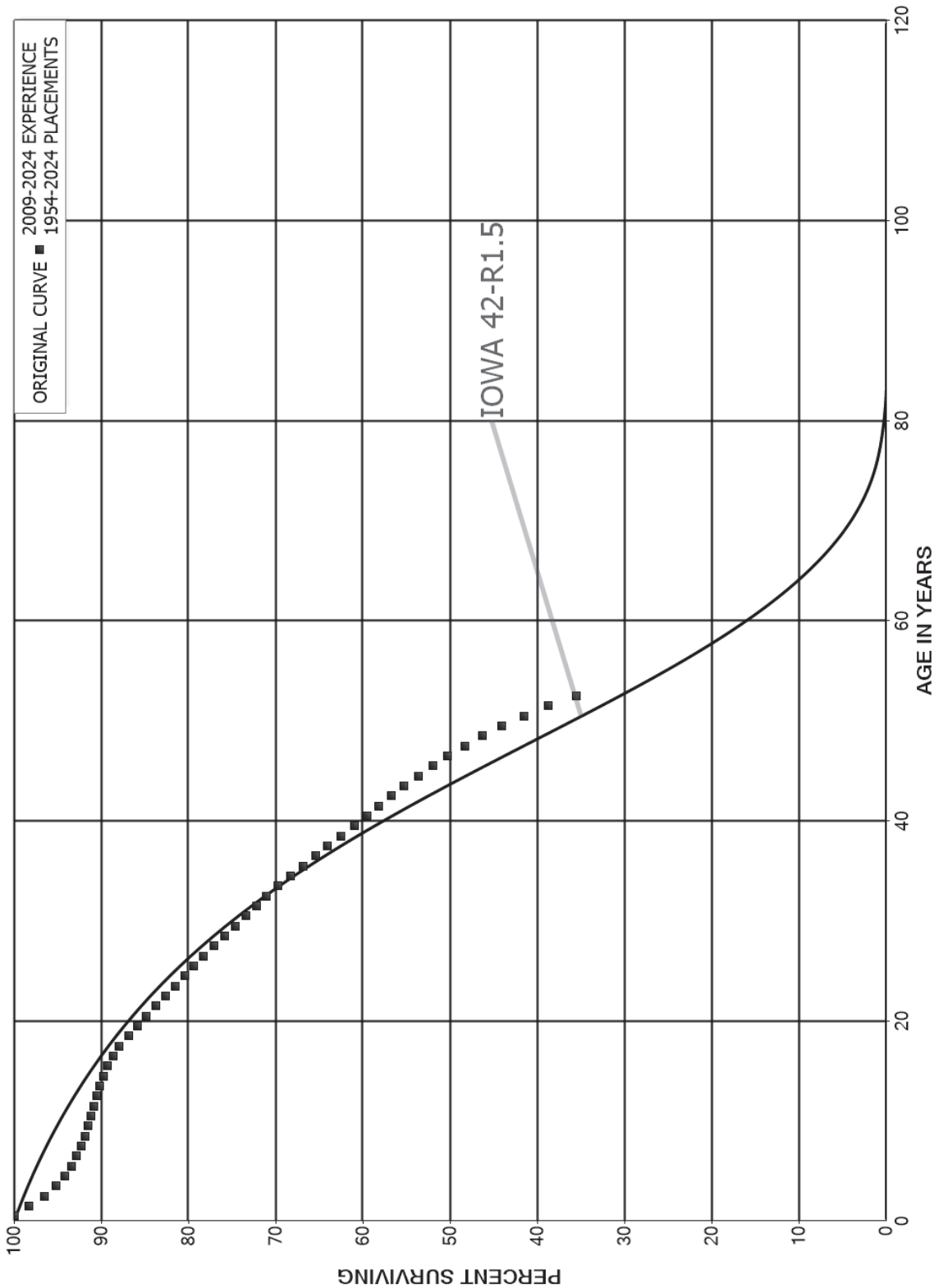
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	22,366,186	332,044	0.0148	0.9852	70.66
40.5	19,085,256	278,351	0.0146	0.9854	69.61
41.5	16,338,007	243,979	0.0149	0.9851	68.60
42.5	13,265,827	200,594	0.0151	0.9849	67.57
43.5	9,972,253	148,107	0.0149	0.9851	66.55
44.5	7,308,483	100,839	0.0138	0.9862	65.56
45.5	5,342,251	70,796	0.0133	0.9867	64.66
46.5	3,882,139	38,275	0.0099	0.9901	63.80
47.5	2,684,336	20,701	0.0077	0.9923	63.17
48.5	1,928,431	8,186	0.0042	0.9958	62.68
49.5	1,442,674	5,360	0.0037	0.9963	62.42
50.5	1,042,970	2,884	0.0028	0.9972	62.19
51.5	698,946	960	0.0014	0.9986	62.01
52.5	444,866		0.0000	1.0000	61.93
53.5	307,507		0.0000	1.0000	61.93
54.5	205,600		0.0000	1.0000	61.93
55.5	129,998		0.0000	1.0000	61.93
56.5	76,552		0.0000	1.0000	61.93
57.5	42,074		0.0000	1.0000	61.93
58.5	22,611		0.0000	1.0000	61.93
59.5	10,911		0.0000	1.0000	61.93
60.5	6,156		0.0000	1.0000	61.93
61.5	3,740		0.0000	1.0000	61.93
62.5	3,740		0.0000	1.0000	61.93
63.5	3,740		0.0000	1.0000	61.93
64.5	3,740		0.0000	1.0000	61.93
65.5	3,740		0.0000	1.0000	61.93
66.5	3,740		0.0000	1.0000	61.93
67.5	3,740		0.0000	1.0000	61.93
68.5	3,740		0.0000	1.0000	61.93
69.5	3,740	0	0.0000	1.0000	61.93
70.5					61.93

KENTUCKY POWER COMPANY  
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	248,147,696	205,605	0.0008	0.9992	100.00
0.5	239,265,138	4,026,521	0.0168	0.9832	99.92
1.5	233,308,256	4,236,713	0.0182	0.9818	98.24
2.5	216,953,178	2,779,950	0.0128	0.9872	96.45
3.5	197,510,572	2,232,419	0.0113	0.9887	95.22
4.5	184,777,015	1,517,077	0.0082	0.9918	94.14
5.5	164,595,710	1,003,121	0.0061	0.9939	93.37
6.5	151,801,947	887,390	0.0058	0.9942	92.80
7.5	143,258,432	684,607	0.0048	0.9952	92.26
8.5	136,103,168	525,496	0.0039	0.9961	91.81
9.5	124,624,850	444,224	0.0036	0.9964	91.46
10.5	113,393,734	360,903	0.0032	0.9968	91.13
11.5	104,749,434	346,752	0.0033	0.9967	90.84
12.5	93,466,310	358,182	0.0038	0.9962	90.54
13.5	91,550,212	432,392	0.0047	0.9953	90.20
14.5	88,242,435	473,756	0.0054	0.9946	89.77
15.5	77,808,324	599,456	0.0077	0.9923	89.29
16.5	73,624,657	546,707	0.0074	0.9926	88.60
17.5	63,860,843	772,121	0.0121	0.9879	87.94
18.5	59,910,072	716,199	0.0120	0.9880	86.88
19.5	59,044,700	727,047	0.0123	0.9877	85.84
20.5	57,040,979	723,297	0.0127	0.9873	84.78
21.5	57,260,366	745,274	0.0130	0.9870	83.71
22.5	56,215,443	735,823	0.0131	0.9869	82.62
23.5	54,257,507	742,946	0.0137	0.9863	81.54
24.5	49,868,225	664,379	0.0133	0.9867	80.42
25.5	47,648,150	651,465	0.0137	0.9863	79.35
26.5	46,915,295	697,420	0.0149	0.9851	78.26
27.5	42,885,303	705,604	0.0165	0.9835	77.10
28.5	41,922,919	656,448	0.0157	0.9843	75.83
29.5	38,707,648	641,641	0.0166	0.9834	74.65
30.5	36,242,906	594,734	0.0164	0.9836	73.41
31.5	35,422,477	569,877	0.0161	0.9839	72.20
32.5	32,991,269	603,373	0.0183	0.9817	71.04
33.5	30,234,601	642,097	0.0212	0.9788	69.74
34.5	27,423,123	582,149	0.0212	0.9788	68.26
35.5	24,855,570	534,516	0.0215	0.9785	66.81
36.5	22,781,566	464,748	0.0204	0.9796	65.38
37.5	20,267,593	493,885	0.0244	0.9756	64.04
38.5	17,981,719	457,069	0.0254	0.9746	62.48

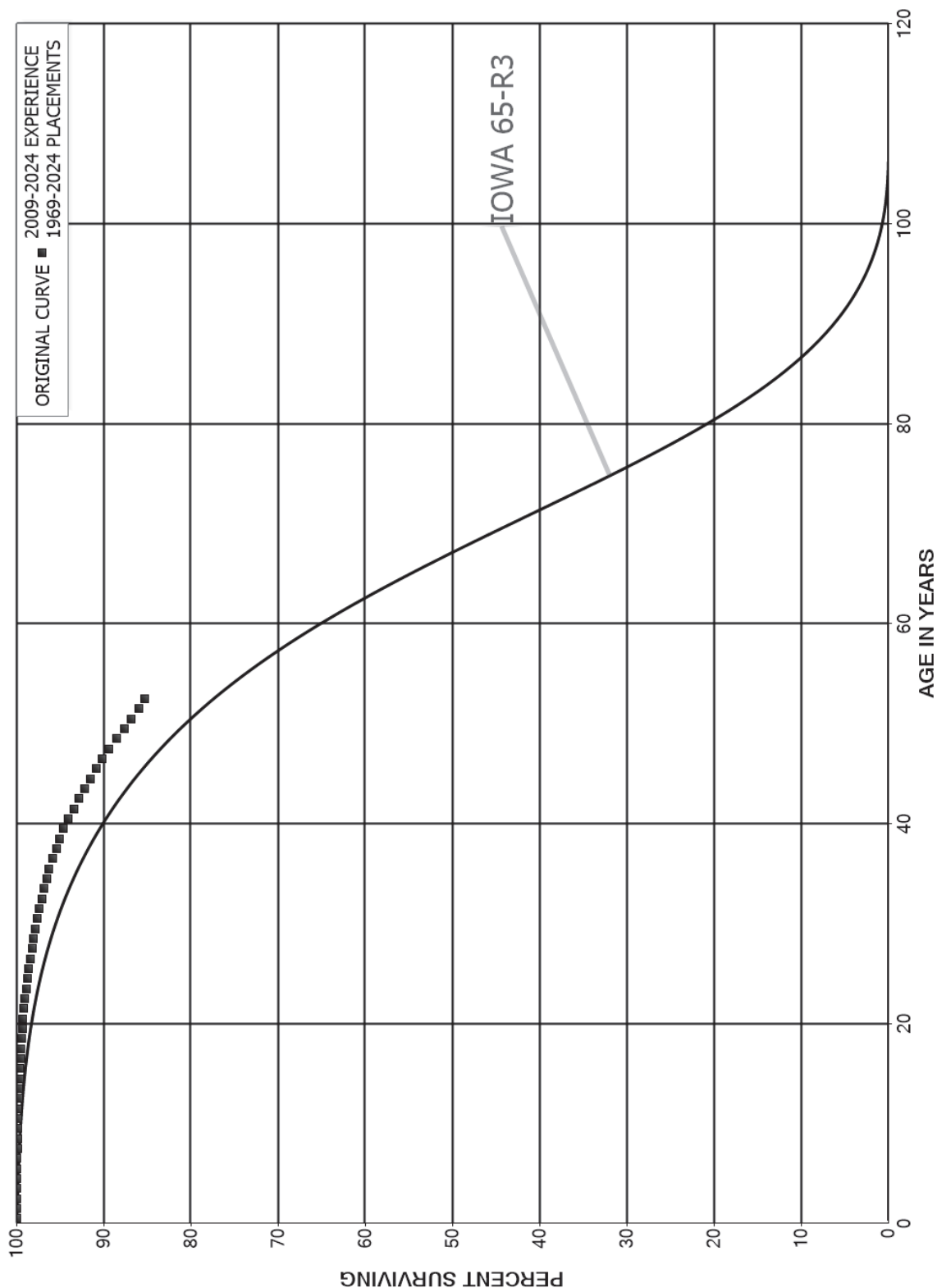
KENTUCKY POWER COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2024			EXPERIENCE BAND 2009-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	16,218,078	368,183	0.0227	0.9773	60.89
40.5	14,666,177	332,460	0.0227	0.9773	59.51
41.5	13,060,366	322,191	0.0247	0.9753	58.16
42.5	11,401,824	288,060	0.0253	0.9747	56.73
43.5	9,070,475	269,528	0.0297	0.9703	55.29
44.5	7,203,609	223,707	0.0311	0.9689	53.65
45.5	5,645,255	188,489	0.0334	0.9666	51.98
46.5	4,397,066	172,080	0.0391	0.9609	50.25
47.5	2,997,095	123,257	0.0411	0.9589	48.28
48.5	2,496,741	120,139	0.0481	0.9519	46.30
49.5	2,045,126	118,846	0.0581	0.9419	44.07
50.5	1,600,926	109,024	0.0681	0.9319	41.51
51.5	1,198,613	97,430	0.0813	0.9187	38.68
52.5	777,196	59,541	0.0766	0.9234	35.54
53.5	516,088	38,890	0.0754	0.9246	32.81
54.5	340,061	25,102	0.0738	0.9262	30.34
55.5	209,836	15,207	0.0725	0.9275	28.10
56.5	121,469	8,243	0.0679	0.9321	26.07
57.5	69,022	4,229	0.0613	0.9387	24.30
58.5	34,959	2,046	0.0585	0.9415	22.81
59.5	18,733	1,089	0.0581	0.9419	21.47
60.5	11,384	609	0.0535	0.9465	20.22
61.5	6,672	294	0.0440	0.9560	19.14
62.5	3,393	147	0.0433	0.9567	18.30
63.5	1,998	80	0.0401	0.9599	17.51
64.5	1,125	65	0.0574	0.9426	16.81
65.5	695	38	0.0550	0.9450	15.84
66.5	513	35	0.0685	0.9315	14.97
67.5	445	36	0.0816	0.9184	13.94
68.5	401	32	0.0793	0.9207	12.81
69.5	369	18	0.0492	0.9508	11.79
70.5					11.21

KENTUCKY POWER COMPANY  
ACCOUNT 366.00 UNDERGROUND CONDUIT  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,817,985		0.0000	1.0000	100.00
0.5	6,243,094	441	0.0001	0.9999	100.00
1.5	6,336,216	3,858	0.0006	0.9994	99.99
2.5	6,421,126	440	0.0001	0.9999	99.93
3.5	5,084,934	497	0.0001	0.9999	99.93
4.5	5,001,106	506	0.0001	0.9999	99.92
5.5	4,851,505	625	0.0001	0.9999	99.91
6.5	4,805,382	638	0.0001	0.9999	99.89
7.5	4,743,986	632	0.0001	0.9999	99.88
8.5	4,769,952	466	0.0001	0.9999	99.87
9.5	4,730,704	713	0.0002	0.9998	99.86
10.5	4,640,227	1,810	0.0004	0.9996	99.84
11.5	4,322,739	1,275	0.0003	0.9997	99.80
12.5	4,133,278	2,131	0.0005	0.9995	99.77
13.5	4,029,908	2,183	0.0005	0.9995	99.72
14.5	3,906,565	2,711	0.0007	0.9993	99.67
15.5	3,493,996	1,910	0.0005	0.9995	99.60
16.5	3,066,985	2,027	0.0007	0.9993	99.54
17.5	2,984,577	2,100	0.0007	0.9993	99.48
18.5	2,646,531	1,815	0.0007	0.9993	99.41
19.5	2,420,705	2,165	0.0009	0.9991	99.34
20.5	2,314,834	2,233	0.0010	0.9990	99.25
21.5	2,177,540	3,158	0.0015	0.9985	99.16
22.5	2,088,309	2,672	0.0013	0.9987	99.01
23.5	2,025,793	3,005	0.0015	0.9985	98.88
24.5	1,860,271	2,999	0.0016	0.9984	98.74
25.5	1,726,549	3,050	0.0018	0.9982	98.58
26.5	1,414,469	2,581	0.0018	0.9982	98.40
27.5	1,210,937	2,540	0.0021	0.9979	98.23
28.5	1,073,196	2,334	0.0022	0.9978	98.02
29.5	952,239	2,298	0.0024	0.9976	97.81
30.5	833,171	1,929	0.0023	0.9977	97.57
31.5	690,568	1,763	0.0026	0.9974	97.34
32.5	571,888	1,568	0.0027	0.9973	97.10
33.5	507,367	1,506	0.0030	0.9970	96.83
34.5	484,559	1,520	0.0031	0.9969	96.54
35.5	441,160	1,743	0.0040	0.9960	96.24
36.5	442,484	2,019	0.0046	0.9954	95.86
37.5	424,432	1,810	0.0043	0.9957	95.42
38.5	416,251	1,948	0.0047	0.9953	95.01



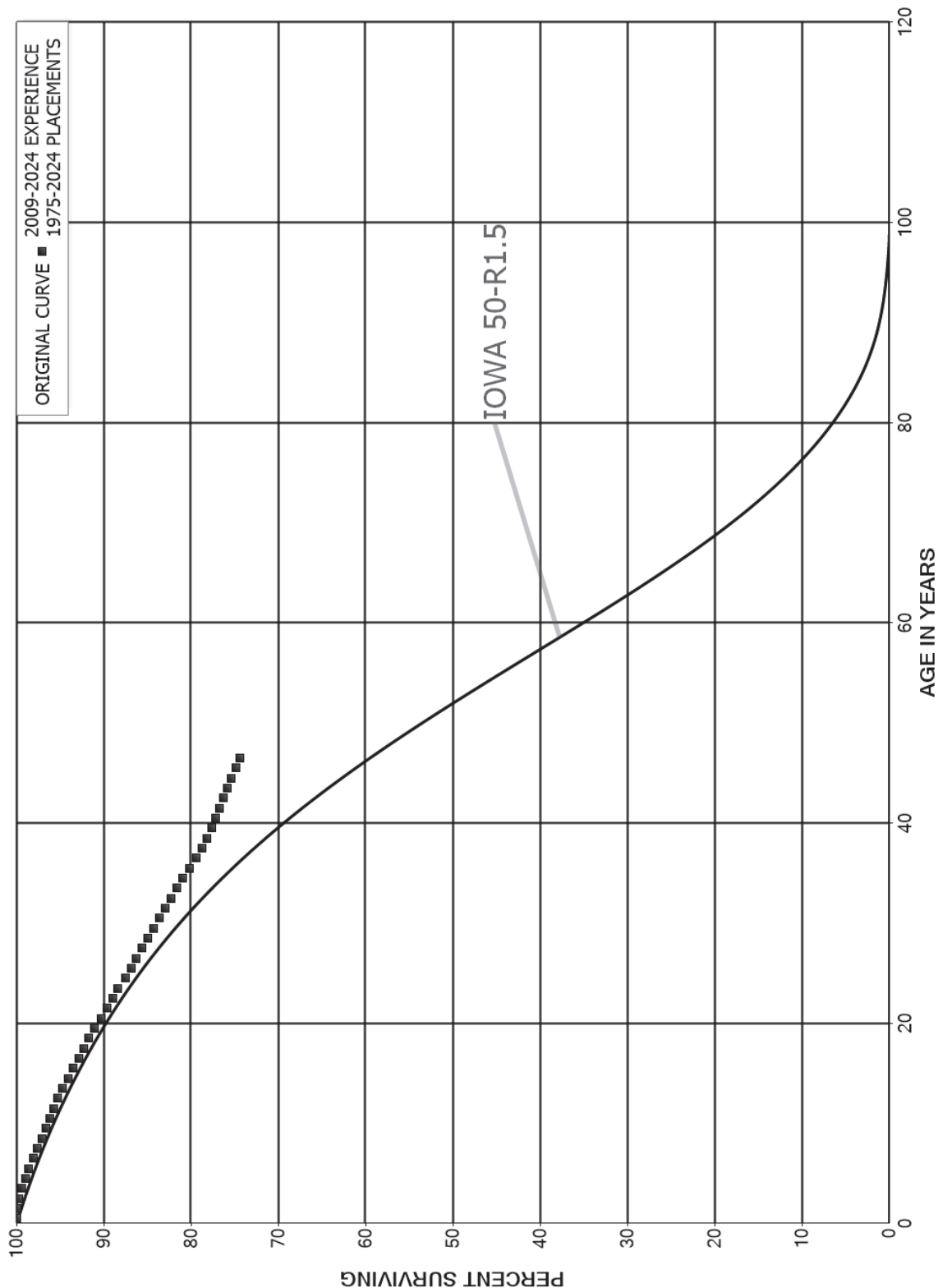
KENTUCKY POWER COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2024			EXPERIENCE BAND 2009-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	379,000	2,127	0.0056	0.9944	94.57
40.5	360,421	2,265	0.0063	0.9937	94.04
41.5	334,228	2,021	0.0060	0.9940	93.45
42.5	311,589	2,356	0.0076	0.9924	92.88
43.5	287,261	2,020	0.0070	0.9930	92.18
44.5	259,204	1,870	0.0072	0.9928	91.53
45.5	222,996	1,764	0.0079	0.9921	90.87
46.5	194,467	1,577	0.0081	0.9919	90.15
47.5	175,462	1,780	0.0101	0.9899	89.42
48.5	172,407	1,669	0.0097	0.9903	88.51
49.5	141,860	1,397	0.0098	0.9902	87.66
50.5	101,458	958	0.0094	0.9906	86.79
51.5	74,620	598	0.0080	0.9920	85.97
52.5	36,857	270	0.0073	0.9927	85.29
53.5	17,613	77	0.0043	0.9957	84.66
54.5	1,371		0.0000	1.0000	84.29
55.5					84.29

KENTUCKY POWER COMPANY  
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,606,410	202	0.0000	1.0000	100.00
0.5	6,912,359	5,659	0.0008	0.9992	100.00
1.5	7,399,499	16,539	0.0022	0.9978	99.92
2.5	7,672,269	23,672	0.0031	0.9969	99.69
3.5	7,688,302	29,066	0.0038	0.9962	99.38
4.5	7,920,150	34,025	0.0043	0.9957	99.01
5.5	7,953,526	39,854	0.0050	0.9950	98.58
6.5	7,832,518	41,686	0.0053	0.9947	98.09
7.5	7,611,383	38,245	0.0050	0.9950	97.57
8.5	7,641,314	37,339	0.0049	0.9951	97.08
9.5	7,254,426	33,312	0.0046	0.9954	96.60
10.5	7,280,852	34,416	0.0047	0.9953	96.16
11.5	6,663,038	29,506	0.0044	0.9956	95.70
12.5	6,425,646	34,652	0.0054	0.9946	95.28
13.5	6,135,261	42,390	0.0069	0.9931	94.77
14.5	5,964,030	40,028	0.0067	0.9933	94.11
15.5	5,762,092	38,947	0.0068	0.9932	93.48
16.5	5,417,335	34,711	0.0064	0.9936	92.85
17.5	4,859,336	30,013	0.0062	0.9938	92.25
18.5	4,260,449	29,951	0.0070	0.9930	91.68
19.5	3,922,635	31,056	0.0079	0.9921	91.04
20.5	3,385,291	27,000	0.0080	0.9920	90.32
21.5	3,209,536	21,934	0.0068	0.9932	89.60
22.5	3,067,926	21,269	0.0069	0.9931	88.99
23.5	2,938,820	29,409	0.0100	0.9900	88.37
24.5	2,593,794	19,234	0.0074	0.9926	87.48
25.5	2,480,255	16,165	0.0065	0.9935	86.84
26.5	1,993,113	16,156	0.0081	0.9919	86.27
27.5	1,804,814	12,890	0.0071	0.9929	85.57
28.5	1,681,179	13,586	0.0081	0.9919	84.96
29.5	1,583,691	12,847	0.0081	0.9919	84.27
30.5	1,459,338	10,127	0.0069	0.9931	83.59
31.5	1,322,063	11,028	0.0083	0.9917	83.01
32.5	1,188,533	9,965	0.0084	0.9916	82.32
33.5	1,066,863	8,630	0.0081	0.9919	81.63
34.5	967,766	8,868	0.0092	0.9908	80.97
35.5	832,855	8,142	0.0098	0.9902	80.22
36.5	732,070	6,323	0.0086	0.9914	79.44
37.5	652,525	4,824	0.0074	0.9926	78.75
38.5	597,663	3,947	0.0066	0.9934	78.17

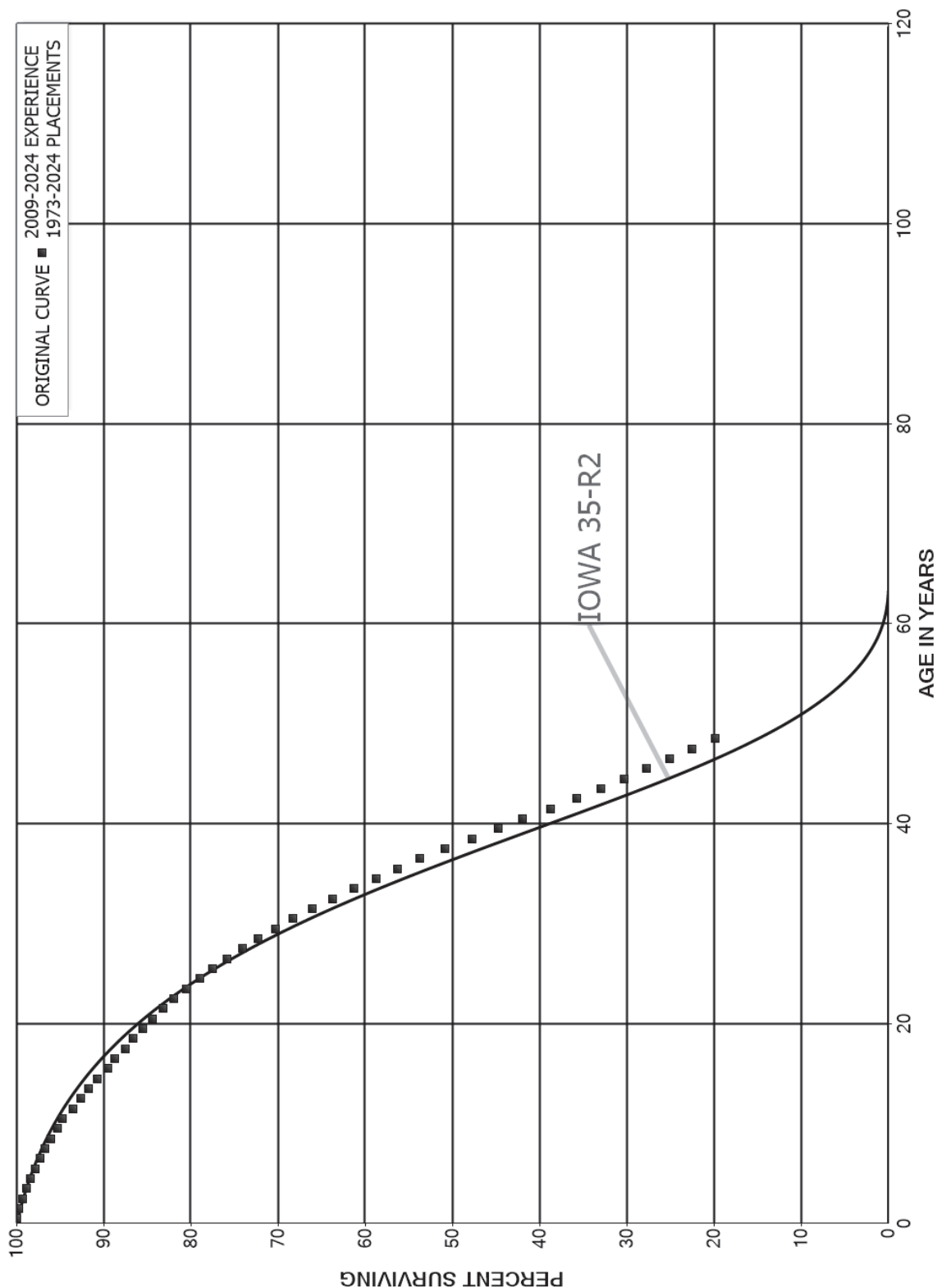
KENTUCKY POWER COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1975-2024			EXPERIENCE BAND 2009-2024			
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL	
39.5	520,566	2,958	0.0057	0.9943	77.66	
40.5	465,706	2,823	0.0061	0.9939	77.21	
41.5	408,977	2,741	0.0067	0.9933	76.75	
42.5	357,390	1,999	0.0056	0.9944	76.23	
43.5	297,886	1,650	0.0055	0.9945	75.81	
44.5	226,046	1,509	0.0067	0.9933	75.39	
45.5	144,993	851	0.0059	0.9941	74.88	
46.5	96,997	607	0.0063	0.9937	74.44	
47.5	50,104	414	0.0083	0.9917	73.98	
48.5	21,905	142	0.0065	0.9935	73.37	
49.5					72.89	

KENTUCKY POWER COMPANY  
ACCOUNT 368.00 LINE TRANSFORMERS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1973-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	101,581,443	8,745	0.0001	0.9999	100.00
0.5	101,759,032	250,182	0.0025	0.9975	99.99
1.5	100,573,638	454,093	0.0045	0.9955	99.75
2.5	97,409,392	483,054	0.0050	0.9950	99.30
3.5	91,905,953	393,116	0.0043	0.9957	98.80
4.5	86,385,808	459,667	0.0053	0.9947	98.38
5.5	81,321,439	485,887	0.0060	0.9940	97.86
6.5	77,322,952	449,196	0.0058	0.9942	97.27
7.5	73,847,335	522,439	0.0071	0.9929	96.71
8.5	72,471,268	523,285	0.0072	0.9928	96.02
9.5	69,724,211	477,959	0.0069	0.9931	95.33
10.5	73,723,019	888,242	0.0120	0.9880	94.68
11.5	70,063,990	689,850	0.0098	0.9902	93.54
12.5	65,633,186	631,821	0.0096	0.9904	92.61
13.5	63,215,790	703,711	0.0111	0.9889	91.72
14.5	61,123,073	782,442	0.0128	0.9872	90.70
15.5	58,976,675	569,644	0.0097	0.9903	89.54
16.5	55,173,632	721,706	0.0131	0.9869	88.68
17.5	50,474,833	535,616	0.0106	0.9894	87.52
18.5	48,224,042	599,283	0.0124	0.9876	86.59
19.5	48,207,307	635,355	0.0132	0.9868	85.51
20.5	47,569,004	693,495	0.0146	0.9854	84.38
21.5	47,187,272	678,136	0.0144	0.9856	83.15
22.5	47,244,651	816,861	0.0173	0.9827	81.96
23.5	46,512,979	915,527	0.0197	0.9803	80.54
24.5	44,120,626	826,559	0.0187	0.9813	78.96
25.5	41,495,654	869,526	0.0210	0.9790	77.48
26.5	33,939,423	788,247	0.0232	0.9768	75.85
27.5	32,613,157	772,260	0.0237	0.9763	74.09
28.5	31,006,121	902,854	0.0291	0.9709	72.34
29.5	29,292,545	803,821	0.0274	0.9726	70.23
30.5	27,723,555	905,828	0.0327	0.9673	68.30
31.5	25,876,102	930,040	0.0359	0.9641	66.07
32.5	23,598,416	903,792	0.0383	0.9617	63.70
33.5	21,192,966	867,782	0.0409	0.9591	61.26
34.5	19,900,603	838,038	0.0421	0.9579	58.75
35.5	17,760,226	796,818	0.0449	0.9551	56.28
36.5	15,484,334	826,149	0.0534	0.9466	53.75
37.5	13,205,826	825,051	0.0625	0.9375	50.88
38.5	10,858,413	668,889	0.0616	0.9384	47.70

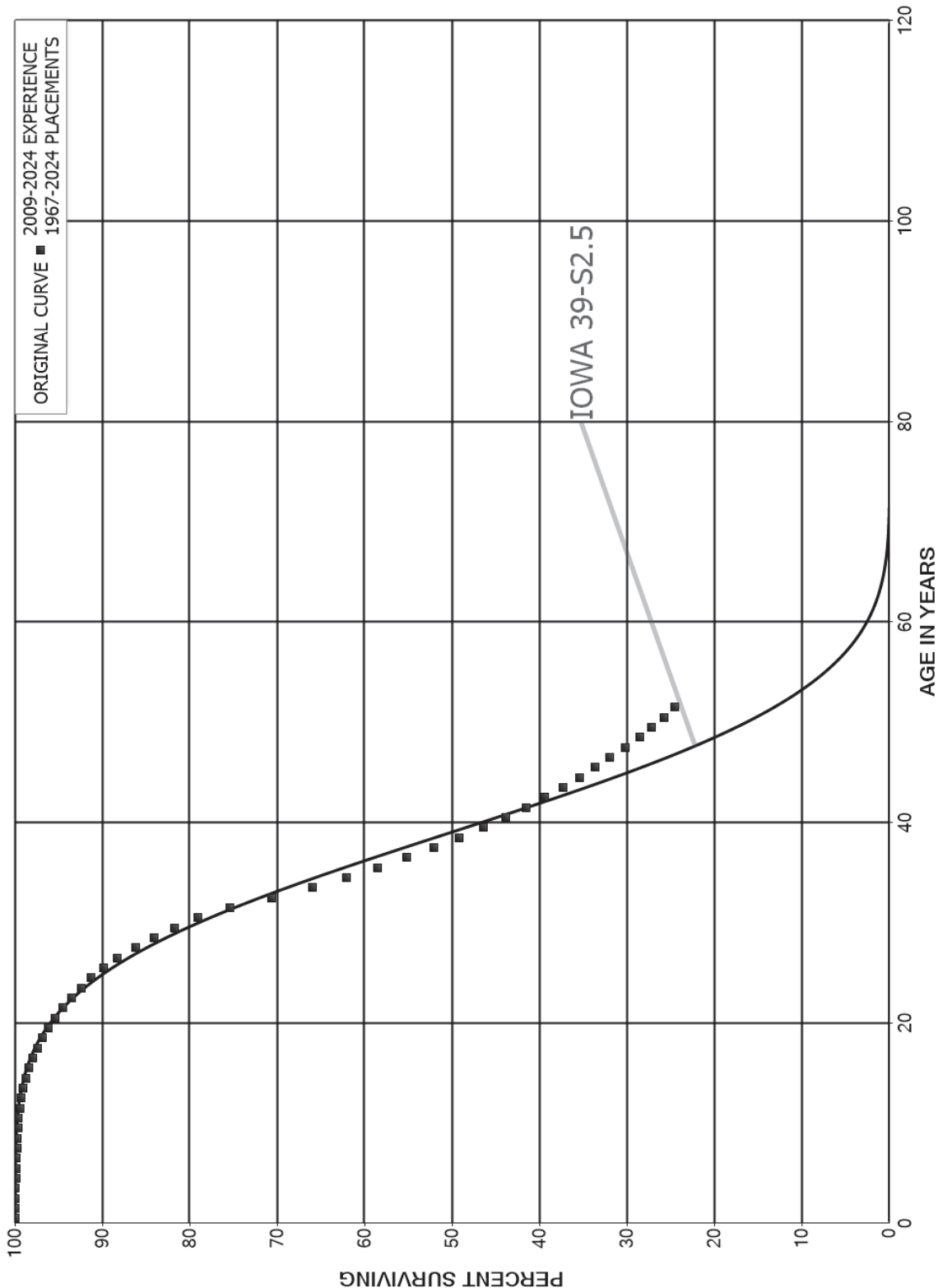
KENTUCKY POWER COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1973-2024			EXPERIENCE BAND 2009-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,971,098	565,395	0.0630	0.9370	44.77
40.5	7,504,910	576,856	0.0769	0.9231	41.94
41.5	6,313,861	485,958	0.0770	0.9230	38.72
42.5	5,270,079	402,935	0.0765	0.9235	35.74
43.5	4,058,368	333,919	0.0823	0.9177	33.01
44.5	3,047,999	262,285	0.0861	0.9139	30.29
45.5	2,121,962	203,151	0.0957	0.9043	27.68
46.5	1,417,597	144,069	0.1016	0.8984	25.03
47.5	928,825	108,368	0.1167	0.8833	22.49
48.5	623,210	87,898	0.1410	0.8590	19.87
49.5	453,926	74,427	0.1640	0.8360	17.06
50.5	118,029	21,360	0.1810	0.8190	14.27
51.5					11.68

KENTUCKY POWER COMPANY  
ACCOUNT 369.00 SERVICES  
ORIGINAL AND SMOOTH SURVIVOR CURVES





KENTUCKY POWER COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	47,486,058		0.0000	1.0000	100.00
0.5	47,428,541	3,492	0.0001	0.9999	100.00
1.5	46,748,701	9,564	0.0002	0.9998	99.99
2.5	46,535,929	19,100	0.0004	0.9996	99.97
3.5	45,043,598	20,970	0.0005	0.9995	99.93
4.5	43,637,154	13,118	0.0003	0.9997	99.88
5.5	42,558,611	13,224	0.0003	0.9997	99.85
6.5	41,826,787	20,054	0.0005	0.9995	99.82
7.5	41,304,080	17,902	0.0004	0.9996	99.78
8.5	42,406,917	34,382	0.0008	0.9992	99.73
9.5	41,625,266	36,550	0.0009	0.9991	99.65
10.5	39,959,978	47,133	0.0012	0.9988	99.56
11.5	37,724,306	75,642	0.0020	0.9980	99.45
12.5	34,721,593	81,443	0.0023	0.9977	99.25
13.5	32,775,189	88,944	0.0027	0.9973	99.01
14.5	30,789,273	104,927	0.0034	0.9966	98.75
15.5	28,117,279	127,361	0.0045	0.9955	98.41
16.5	26,205,130	141,114	0.0054	0.9946	97.96
17.5	24,614,412	153,161	0.0062	0.9938	97.44
18.5	22,714,064	153,379	0.0068	0.9932	96.83
19.5	21,314,063	176,155	0.0083	0.9917	96.18
20.5	19,843,808	179,705	0.0091	0.9909	95.38
21.5	18,374,046	188,258	0.0102	0.9898	94.52
22.5	17,463,053	211,024	0.0121	0.9879	93.55
23.5	16,342,757	205,843	0.0126	0.9874	92.42
24.5	13,578,424	205,586	0.0151	0.9849	91.25
25.5	12,498,030	221,793	0.0177	0.9823	89.87
26.5	12,048,248	281,380	0.0234	0.9766	88.28
27.5	10,216,903	260,501	0.0255	0.9745	86.22
28.5	9,788,416	267,727	0.0274	0.9726	84.02
29.5	9,056,301	297,818	0.0329	0.9671	81.72
30.5	8,278,166	383,635	0.0463	0.9537	79.03
31.5	7,087,400	446,926	0.0631	0.9369	75.37
32.5	6,102,379	401,499	0.0658	0.9342	70.62
33.5	5,139,665	303,807	0.0591	0.9409	65.97
34.5	4,429,583	251,074	0.0567	0.9433	62.07
35.5	3,719,332	212,845	0.0572	0.9428	58.55
36.5	3,196,298	181,472	0.0568	0.9432	55.20
37.5	2,673,703	151,118	0.0565	0.9435	52.07
38.5	2,270,514	125,126	0.0551	0.9449	49.13

KENTUCKY POWER COMPANY

ACCOUNT 369.00 SERVICES

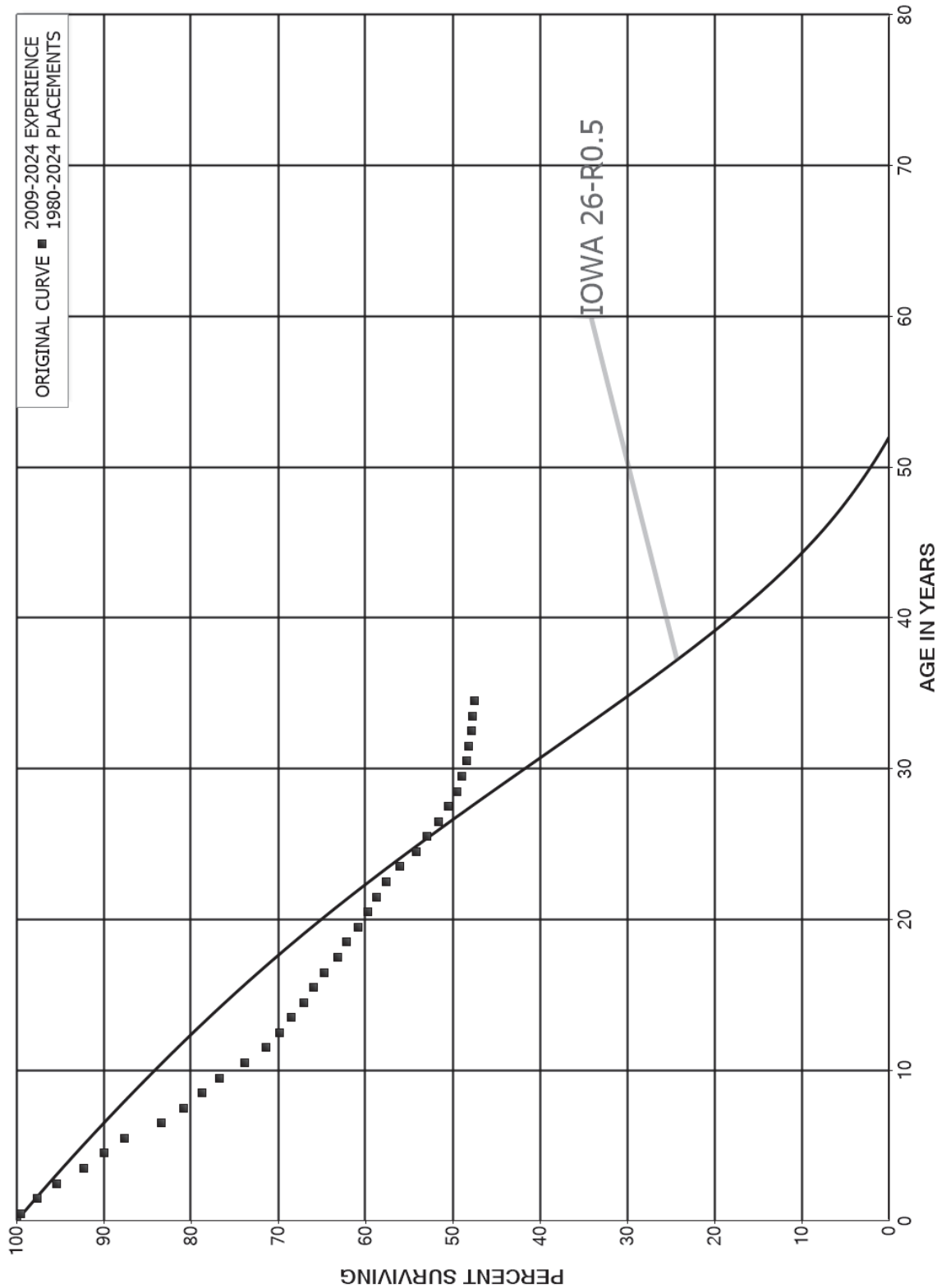
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,914,340	104,519	0.0546	0.9454	46.42
40.5	1,568,848	83,291	0.0531	0.9469	43.88
41.5	1,263,112	67,270	0.0533	0.9467	41.55
42.5	1,039,202	52,990	0.0510	0.9490	39.34
43.5	840,608	43,204	0.0514	0.9486	37.33
44.5	658,664	34,129	0.0518	0.9482	35.42
45.5	506,995	25,284	0.0499	0.9501	33.58
46.5	369,621	19,672	0.0532	0.9468	31.91
47.5	267,238	14,683	0.0549	0.9451	30.21
48.5	195,115	9,681	0.0496	0.9504	28.55
49.5	140,211	7,247	0.0517	0.9483	27.13
50.5	103,864	4,844	0.0466	0.9534	25.73
51.5	63,812	2,676	0.0419	0.9581	24.53
52.5	33,767	1,420	0.0421	0.9579	23.50
53.5	18,590		0.0000	1.0000	22.51
54.5	11,011		0.0000	1.0000	22.51
55.5	6,191		0.0000	1.0000	22.51
56.5	2,790		0.0000	1.0000	22.51
57.5					22.51

KENTUCKY POWER COMPANY  
ACCOUNT 370.00 METERS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,738,936	67,876	0.0049	0.9951	100.00
0.5	16,231,656	308,212	0.0190	0.9810	99.51
1.5	17,506,142	401,595	0.0229	0.9771	97.62
2.5	30,287,887	981,949	0.0324	0.9676	95.38
3.5	29,853,219	765,397	0.0256	0.9744	92.28
4.5	29,372,833	769,574	0.0262	0.9738	89.92
5.5	28,084,439	1,328,153	0.0473	0.9527	87.56
6.5	26,731,104	830,446	0.0311	0.9689	83.42
7.5	25,207,571	652,037	0.0259	0.9741	80.83
8.5	23,501,898	614,861	0.0262	0.9738	78.74
9.5	22,316,488	822,678	0.0369	0.9631	76.68
10.5	21,016,869	698,147	0.0332	0.9668	73.85
11.5	19,905,829	442,487	0.0222	0.9778	71.40
12.5	17,756,995	345,552	0.0195	0.9805	69.81
13.5	16,843,317	331,289	0.0197	0.9803	68.45
14.5	15,896,625	287,084	0.0181	0.9819	67.11
15.5	14,899,235	266,993	0.0179	0.9821	65.90
16.5	12,590,895	308,324	0.0245	0.9755	64.71
17.5	10,998,117	173,715	0.0158	0.9842	63.13
18.5	2,678,453	54,167	0.0202	0.9798	62.13
19.5	2,027,912	39,602	0.0195	0.9805	60.88
20.5	1,678,719	26,955	0.0161	0.9839	59.69
21.5	1,600,224	30,548	0.0191	0.9809	58.73
22.5	961,934	26,505	0.0276	0.9724	57.61
23.5	702,815	22,647	0.0322	0.9678	56.02
24.5	667,414	15,435	0.0231	0.9769	54.22
25.5	544,219	13,662	0.0251	0.9749	52.96
26.5	386,315	8,459	0.0219	0.9781	51.63
27.5	295,082	5,535	0.0188	0.9812	50.50
28.5	265,096	2,942	0.0111	0.9889	49.55
29.5	230,257	2,993	0.0130	0.9870	49.00
30.5	170,792	835	0.0049	0.9951	48.37
31.5	140,654	831	0.0059	0.9941	48.13
32.5	119,128	307	0.0026	0.9974	47.85
33.5	106,433	412	0.0039	0.9961	47.72
34.5	66,468	2,031	0.0305	0.9695	47.54
35.5	51,101		0.0000	1.0000	46.09
36.5	38,886		0.0000	1.0000	46.09
37.5	30,885	3,964	0.1284	0.8716	46.09
38.5	22,022		0.0000	1.0000	40.17

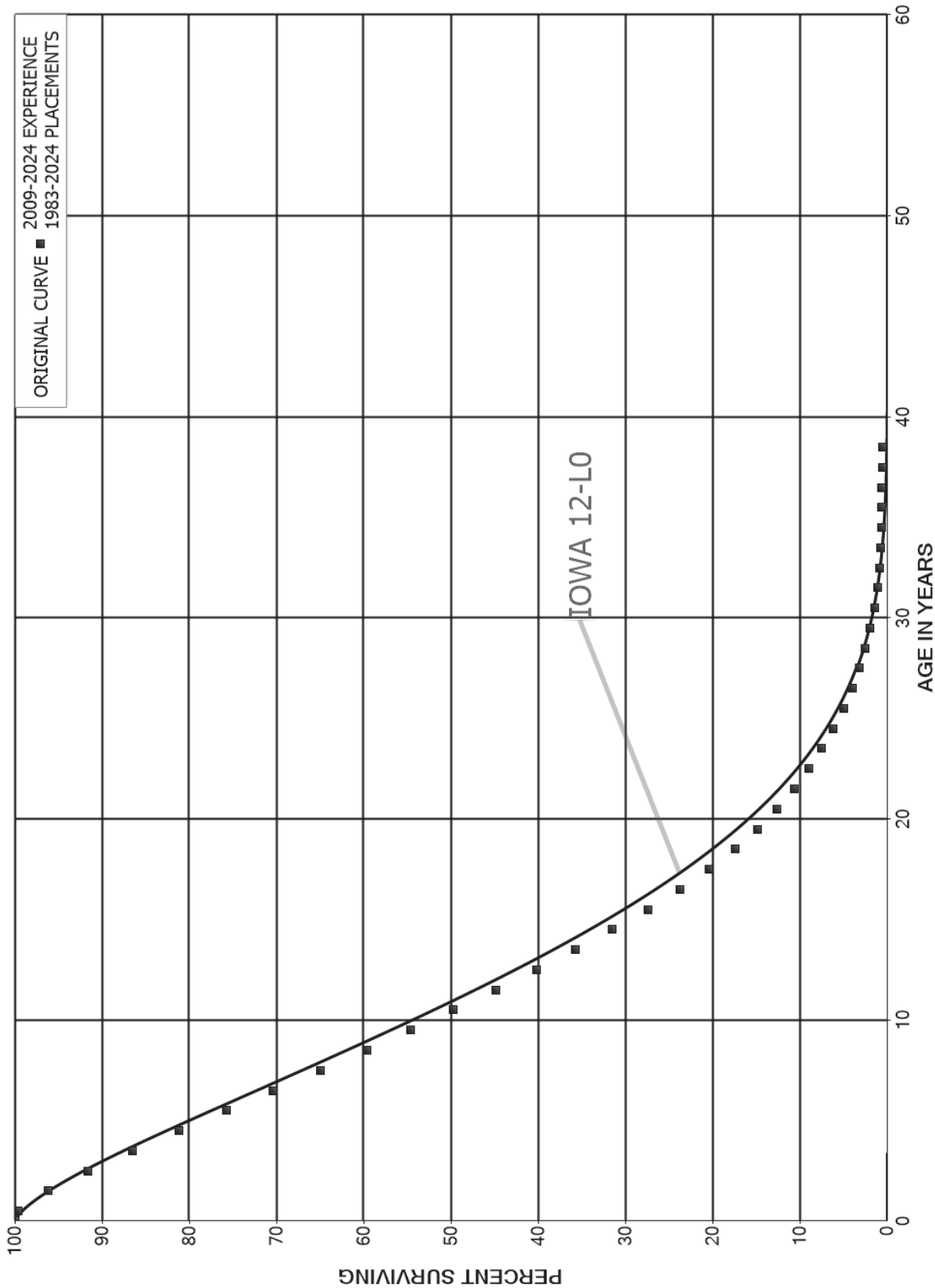
KENTUCKY POWER COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1980-2024			EXPERIENCE BAND 2009-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,539		0.0000	1.0000	40.17
40.5	5,230		0.0000	1.0000	40.17
41.5	3,841		0.0000	1.0000	40.17
42.5	2,697		0.0000	1.0000	40.17
43.5	2,127		0.0000	1.0000	40.17
44.5					40.17

KENTUCKY POWER COMPANY  
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	29,265,433	99,491	0.0034	0.9966	100.00
0.5	27,745,926	976,087	0.0352	0.9648	99.66
1.5	25,232,079	1,185,358	0.0470	0.9530	96.15
2.5	23,091,226	1,299,891	0.0563	0.9437	91.64
3.5	21,190,383	1,304,217	0.0615	0.9385	86.48
4.5	20,021,846	1,326,545	0.0663	0.9337	81.16
5.5	19,138,811	1,363,204	0.0712	0.9288	75.78
6.5	18,633,319	1,449,911	0.0778	0.9222	70.38
7.5	17,465,570	1,409,119	0.0807	0.9193	64.90
8.5	16,640,145	1,397,250	0.0840	0.9160	59.67
9.5	15,491,719	1,405,562	0.0907	0.9093	54.66
10.5	14,048,355	1,388,452	0.0988	0.9012	49.70
11.5	12,863,219	1,327,967	0.1032	0.8968	44.79
12.5	11,302,895	1,243,730	0.1100	0.8900	40.16
13.5	9,903,303	1,184,747	0.1196	0.8804	35.74
14.5	8,929,999	1,143,996	0.1281	0.8719	31.47
15.5	8,107,851	1,099,952	0.1357	0.8643	27.44
16.5	7,025,885	989,133	0.1408	0.8592	23.71
17.5	6,086,329	888,534	0.1460	0.8540	20.38
18.5	5,152,041	756,314	0.1468	0.8532	17.40
19.5	4,377,434	672,493	0.1536	0.8464	14.85
20.5	3,617,131	559,516	0.1547	0.8453	12.57
21.5	2,970,531	471,961	0.1589	0.8411	10.62
22.5	2,408,157	373,216	0.1550	0.8450	8.93
23.5	1,643,118	305,650	0.1860	0.8140	7.55
24.5	1,249,250	236,718	0.1895	0.8105	6.15
25.5	965,576	189,683	0.1964	0.8036	4.98
26.5	744,175	154,039	0.2070	0.7930	4.00
27.5	531,467	117,421	0.2209	0.7791	3.17
28.5	397,233	92,942	0.2340	0.7660	2.47
29.5	288,794	69,672	0.2413	0.7587	1.89
30.5	190,832	44,375	0.2325	0.7675	1.44
31.5	113,608	23,312	0.2052	0.7948	1.10
32.5	73,300	12,723	0.1736	0.8264	0.88
33.5	46,045	4,532	0.0984	0.9016	0.72
34.5	32,185	2,104	0.0654	0.9346	0.65
35.5	19,853	1,577	0.0794	0.9206	0.61
36.5	11,800	716	0.0607	0.9393	0.56
37.5	6,512	535	0.0821	0.9179	0.53
38.5	3,001	533	0.1776	0.8224	0.48

KENTUCKY POWER COMPANY

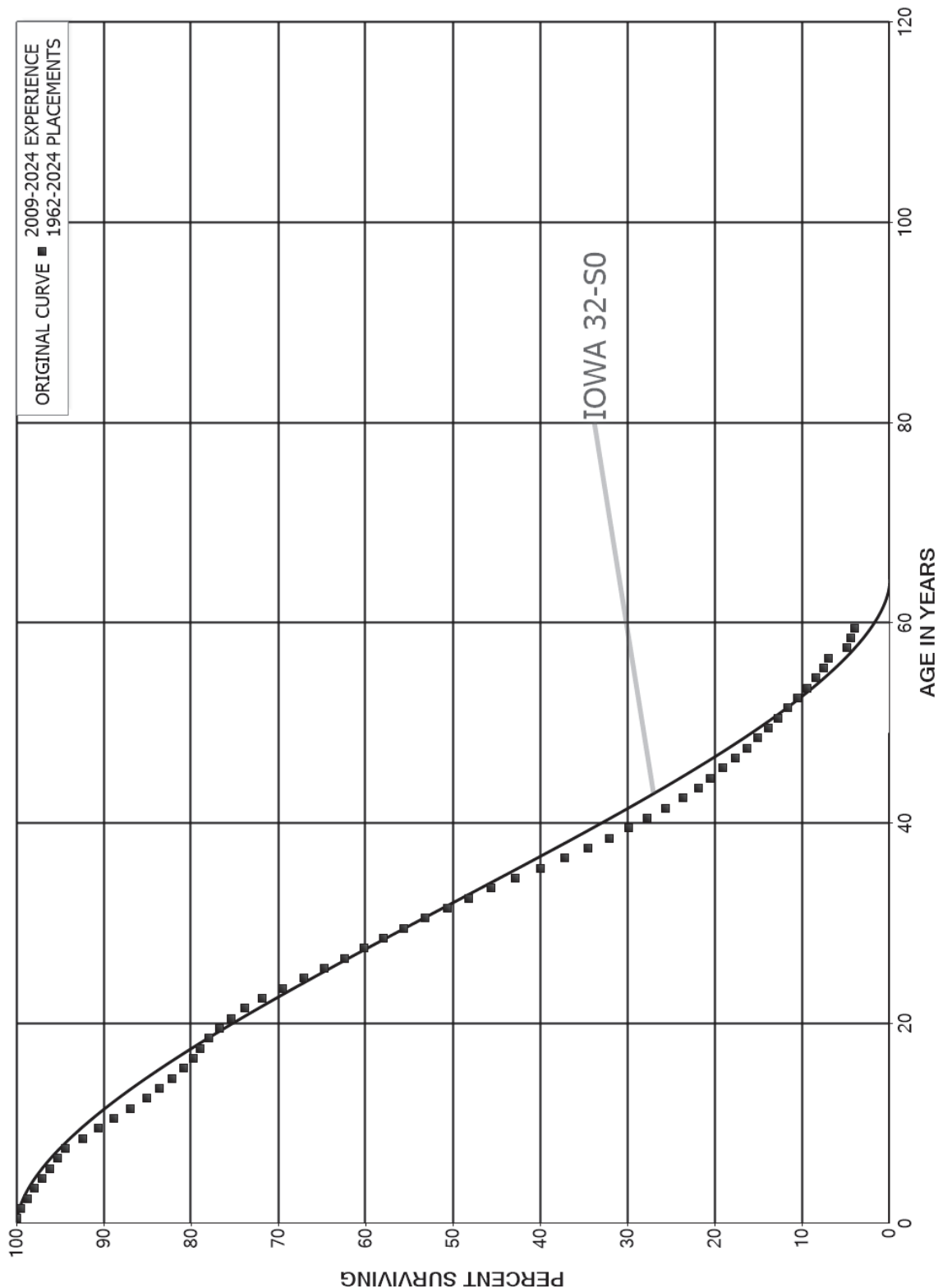
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1983-2024			EXPERIENCE BAND 2009-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,185		0.0000	1.0000	0.40
40.5	297		0.0000	1.0000	0.40
41.5					0.40



KENTUCKY POWER COMPANY  
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1962-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,310,977	78	0.0000	1.0000	100.00
0.5	3,817,183	19,808	0.0052	0.9948	100.00
1.5	3,337,184	25,873	0.0078	0.9922	99.48
2.5	2,974,306	23,874	0.0080	0.9920	98.71
3.5	2,755,153	23,588	0.0086	0.9914	97.92
4.5	2,490,020	21,910	0.0088	0.9912	97.08
5.5	2,286,460	21,601	0.0094	0.9906	96.22
6.5	2,088,593	19,791	0.0095	0.9905	95.31
7.5	1,942,000	40,518	0.0209	0.9791	94.41
8.5	1,687,776	32,635	0.0193	0.9807	92.44
9.5	1,553,483	31,210	0.0201	0.9799	90.65
10.5	1,390,042	29,187	0.0210	0.9790	88.83
11.5	1,183,732	26,085	0.0220	0.9780	86.97
12.5	1,047,013	17,728	0.0169	0.9831	85.05
13.5	1,019,362	17,327	0.0170	0.9830	83.61
14.5	1,022,232	16,284	0.0159	0.9841	82.19
15.5	1,119,633	16,112	0.0144	0.9856	80.88
16.5	1,023,971	10,457	0.0102	0.9898	79.72
17.5	984,362	12,367	0.0126	0.9874	78.90
18.5	1,142,524	17,061	0.0149	0.9851	77.91
19.5	1,394,709	24,949	0.0179	0.9821	76.75
20.5	1,494,407	29,465	0.0197	0.9803	75.37
21.5	1,541,784	43,817	0.0284	0.9716	73.89
22.5	1,648,254	53,351	0.0324	0.9676	71.79
23.5	1,637,000	55,345	0.0338	0.9662	69.46
24.5	1,502,154	53,138	0.0354	0.9646	67.12
25.5	1,474,953	54,201	0.0367	0.9633	64.74
26.5	1,508,189	53,504	0.0355	0.9645	62.36
27.5	1,517,649	56,863	0.0375	0.9625	60.15
28.5	1,480,446	58,020	0.0392	0.9608	57.90
29.5	1,401,195	61,419	0.0438	0.9562	55.63
30.5	1,315,676	63,963	0.0486	0.9514	53.19
31.5	1,161,675	55,223	0.0475	0.9525	50.60
32.5	1,104,136	58,599	0.0531	0.9469	48.20
33.5	1,033,024	63,892	0.0618	0.9382	45.64
34.5	886,384	59,989	0.0677	0.9323	42.82
35.5	706,196	48,372	0.0685	0.9315	39.92
36.5	577,545	41,035	0.0711	0.9289	37.19
37.5	470,742	34,393	0.0731	0.9269	34.54
38.5	387,257	26,952	0.0696	0.9304	32.02

KENTUCKY POWER COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

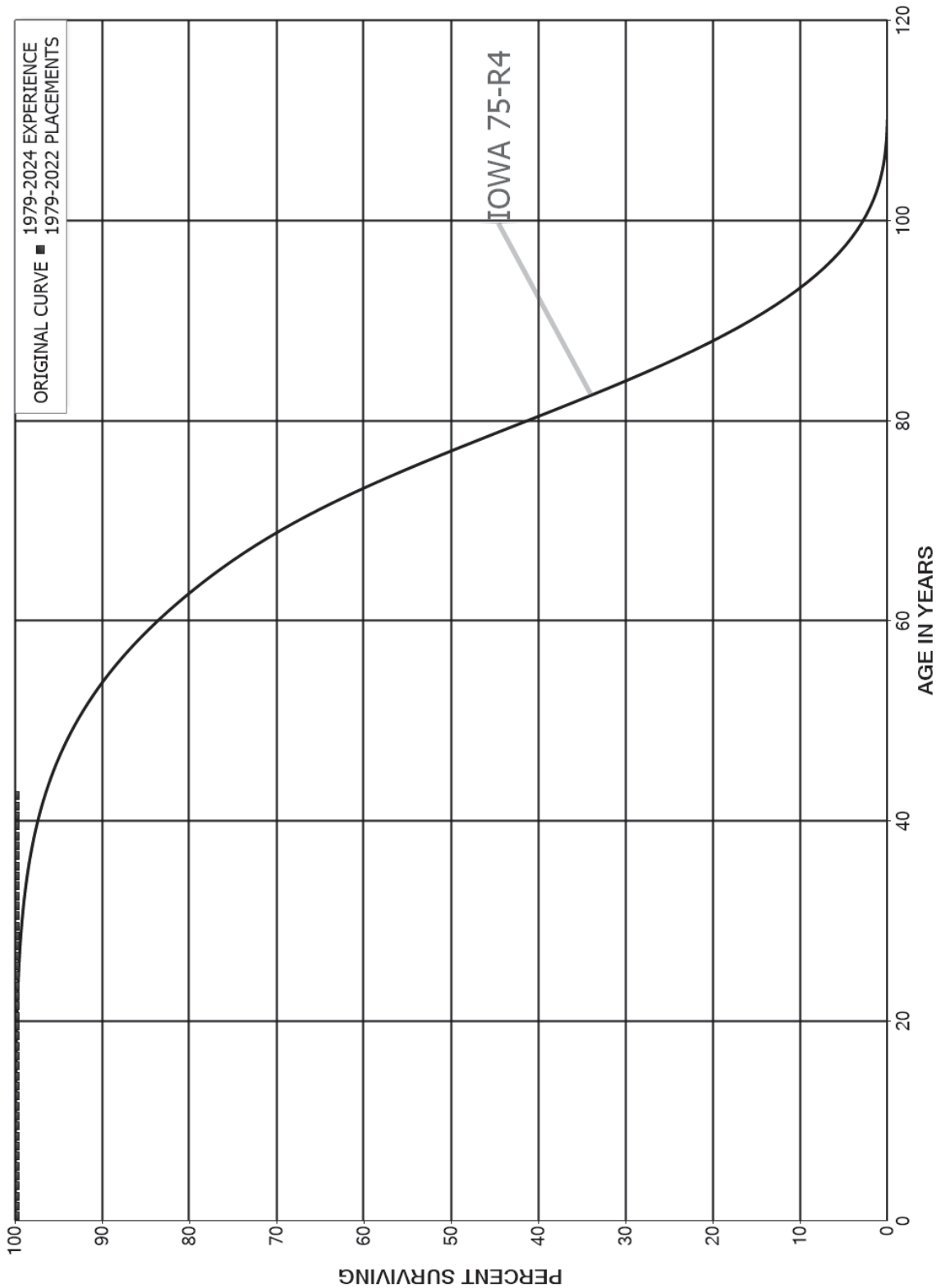
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1962-2024

EXPERIENCE BAND 2009-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	332,792	22,486	0.0676	0.9324	29.79
40.5	310,166	23,938	0.0772	0.9228	27.78
41.5	283,149	22,544	0.0796	0.9204	25.63
42.5	225,127	16,864	0.0749	0.9251	23.59
43.5	180,451	11,077	0.0614	0.9386	21.83
44.5	153,640	10,357	0.0674	0.9326	20.49
45.5	140,149	10,675	0.0762	0.9238	19.11
46.5	121,472	9,737	0.0802	0.9198	17.65
47.5	107,416	7,961	0.0741	0.9259	16.24
48.5	95,456	7,633	0.0800	0.9200	15.03
49.5	82,742	6,714	0.0811	0.9189	13.83
50.5	70,045	5,822	0.0831	0.9169	12.71
51.5	57,586	5,908	0.1026	0.8974	11.65
52.5	48,479	5,160	0.1064	0.8936	10.46
53.5	39,722	3,953	0.0995	0.9005	9.34
54.5	28,945	3,046	0.1052	0.8948	8.41
55.5	22,513	1,689	0.0750	0.9250	7.53
56.5	17,067	5,162	0.3025	0.6975	6.96
57.5	7,520	770	0.1023	0.8977	4.86
58.5	4,765	465	0.0976	0.9024	4.36
59.5	2,187	3	0.0013	0.9987	3.93
60.5	1,949	461	0.2365	0.7635	3.93
61.5	280		0.0000	1.0000	3.00
62.5					3.00

KENTUCKY POWER COMPANY  
ACCOUNT 389.10 LAND RIGHTS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 389.10 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1979-2022

EXPERIENCE BAND 1979-2024

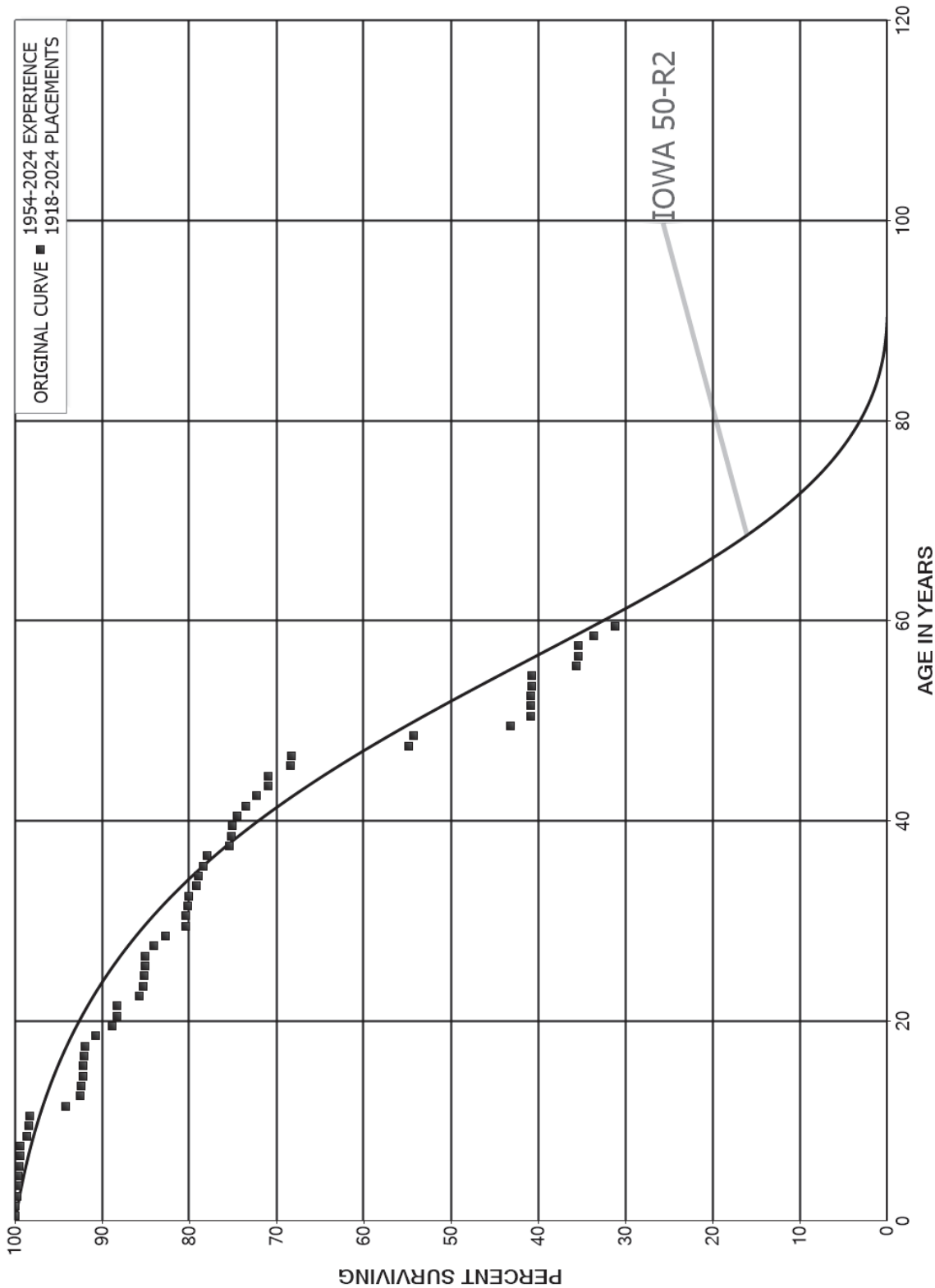
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	35,748		0.0000	1.0000	100.00
0.5	35,748		0.0000	1.0000	100.00
1.5	35,748		0.0000	1.0000	100.00
2.5	35,746		0.0000	1.0000	100.00
3.5	35,746		0.0000	1.0000	100.00
4.5	35,746		0.0000	1.0000	100.00
5.5	35,746		0.0000	1.0000	100.00
6.5	35,746		0.0000	1.0000	100.00
7.5	35,746		0.0000	1.0000	100.00
8.5	35,746		0.0000	1.0000	100.00
9.5	35,746		0.0000	1.0000	100.00
10.5	35,746		0.0000	1.0000	100.00
11.5	35,746		0.0000	1.0000	100.00
12.5	35,746		0.0000	1.0000	100.00
13.5	35,746		0.0000	1.0000	100.00
14.5	35,746		0.0000	1.0000	100.00
15.5	35,746		0.0000	1.0000	100.00
16.5	35,746		0.0000	1.0000	100.00
17.5	35,746		0.0000	1.0000	100.00
18.5	35,746		0.0000	1.0000	100.00
19.5	35,746		0.0000	1.0000	100.00
20.5	35,746		0.0000	1.0000	100.00
21.5	28,246		0.0000	1.0000	100.00
22.5	28,246		0.0000	1.0000	100.00
23.5	28,246		0.0000	1.0000	100.00
24.5	28,246		0.0000	1.0000	100.00
25.5	28,246		0.0000	1.0000	100.00
26.5	28,246		0.0000	1.0000	100.00
27.5	28,246		0.0000	1.0000	100.00
28.5	28,246		0.0000	1.0000	100.00
29.5	28,246		0.0000	1.0000	100.00
30.5	28,246		0.0000	1.0000	100.00
31.5	28,246		0.0000	1.0000	100.00
32.5	28,246		0.0000	1.0000	100.00
33.5	28,246		0.0000	1.0000	100.00
34.5	28,246		0.0000	1.0000	100.00
35.5	28,246		0.0000	1.0000	100.00
36.5	28,246		0.0000	1.0000	100.00
37.5	28,246		0.0000	1.0000	100.00
38.5	5,804		0.0000	1.0000	100.00

KENTUCKY POWER COMPANY  
ACCOUNT 389.10 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1979-2022			EXPERIENCE BAND 1979-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,577		0.0000	1.0000	100.00
40.5	3,899		0.0000	1.0000	100.00
41.5	3,899		0.0000	1.0000	100.00
42.5	3,899		0.0000	1.0000	100.00
43.5	3,899		0.0000	1.0000	100.00
44.5	3,899		0.0000	1.0000	100.00
45.5					100.00

KENTUCKY POWER COMPANY  
ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS  
ORIGINAL AND SMOOTH SURVIVOR CURVES



KENTUCKY POWER COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1918-2024

EXPERIENCE BAND 1954-2024

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	44,131,946	603	0.0000	1.0000	100.00
0.5	42,800,928	1,197	0.0000	1.0000	100.00
1.5	42,651,863	112,308	0.0026	0.9974	100.00
2.5	42,332,190	51,086	0.0012	0.9988	99.73
3.5	41,490,275	12,996	0.0003	0.9997	99.61
4.5	39,497,926	20,953	0.0005	0.9995	99.58
5.5	38,258,894	56,557	0.0015	0.9985	99.53
6.5	36,594,052	11,085	0.0003	0.9997	99.38
7.5	36,051,574	258,727	0.0072	0.9928	99.35
8.5	35,301,600	80,126	0.0023	0.9977	98.64
9.5	35,002,069	43,026	0.0012	0.9988	98.41
10.5	34,516,472	1,428,178	0.0414	0.9586	98.29
11.5	32,645,184	597,953	0.0183	0.9817	94.23
12.5	31,759,733	49,739	0.0016	0.9984	92.50
13.5	30,572,431	45,866	0.0015	0.9985	92.36
14.5	30,531,709	16,056	0.0005	0.9995	92.22
15.5	30,536,334	46,750	0.0015	0.9985	92.17
16.5	30,380,431	17,179	0.0006	0.9994	92.03
17.5	30,345,539	418,032	0.0138	0.9862	91.98
18.5	29,492,482	597,157	0.0202	0.9798	90.71
19.5	28,676,086	178,914	0.0062	0.9938	88.87
20.5	28,445,267	26,412	0.0009	0.9991	88.32
21.5	28,425,069	809,567	0.0285	0.9715	88.23
22.5	27,622,407	146,371	0.0053	0.9947	85.72
23.5	18,560,123	16,561	0.0009	0.9991	85.27
24.5	18,419,768	18,867	0.0010	0.9990	85.19
25.5	18,400,901	14,177	0.0008	0.9992	85.10
26.5	18,429,593	201,172	0.0109	0.9891	85.04
27.5	18,111,948	302,439	0.0167	0.9833	84.11
28.5	16,965,354	468,507	0.0276	0.9724	82.71
29.5	16,053,595	972	0.0001	0.9999	80.42
30.5	16,023,162	52,139	0.0033	0.9967	80.42
31.5	15,962,905	23,958	0.0015	0.9985	80.16
32.5	15,779,934	167,212	0.0106	0.9894	80.04
33.5	15,329,173	43,860	0.0029	0.9971	79.19
34.5	4,375,484	32,402	0.0074	0.9926	78.96
35.5	4,322,416	22,788	0.0053	0.9947	78.38
36.5	4,296,699	143,799	0.0335	0.9665	77.96
37.5	4,141,412	6,902	0.0017	0.9983	75.35
38.5	4,121,939	9,675	0.0023	0.9977	75.23



KENTUCKY POWER COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1918-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,109,759	32,565	0.0079	0.9921	75.05
40.5	4,077,194	49,972	0.0123	0.9877	74.46
41.5	4,015,159	67,898	0.0169	0.9831	73.54
42.5	3,940,204	71,514	0.0181	0.9819	72.30
43.5	355,266	12	0.0000	1.0000	70.99
44.5	349,221	12,999	0.0372	0.9628	70.99
45.5	321,208	100	0.0003	0.9997	68.34
46.5	304,287	60,001	0.1972	0.8028	68.32
47.5	242,872	2,370	0.0098	0.9902	54.85
48.5	234,347	48,292	0.2061	0.7939	54.31
49.5	173,080	9,061	0.0524	0.9476	43.12
50.5	149,866		0.0000	1.0000	40.86
51.5	145,770		0.0000	1.0000	40.86
52.5	145,770	344	0.0024	0.9976	40.86
53.5	145,426		0.0000	1.0000	40.77
54.5	143,220	18,000	0.1257	0.8743	40.77
55.5	112,350	784	0.0070	0.9930	35.64
56.5	86,571		0.0000	1.0000	35.40
57.5	80,340	4,024	0.0501	0.9499	35.40
58.5	74,652	5,320	0.0713	0.9287	33.62
59.5	69,332		0.0000	1.0000	31.23
60.5	69,332		0.0000	1.0000	31.23
61.5	68,851		0.0000	1.0000	31.23
62.5	68,058	368	0.0054	0.9946	31.23
63.5	67,242		0.0000	1.0000	31.06
64.5	52,081		0.0000	1.0000	31.06
65.5	50,497		0.0000	1.0000	31.06
66.5	49,972		0.0000	1.0000	31.06
67.5	49,825		0.0000	1.0000	31.06
68.5	49,825		0.0000	1.0000	31.06
69.5	49,825		0.0000	1.0000	31.06
70.5	49,825		0.0000	1.0000	31.06
71.5	49,320		0.0000	1.0000	31.06
72.5	49,223		0.0000	1.0000	31.06
73.5	49,223		0.0000	1.0000	31.06
74.5	48,919		0.0000	1.0000	31.06
75.5	47,803		0.0000	1.0000	31.06
76.5	47,267		0.0000	1.0000	31.06
77.5	47,267		0.0000	1.0000	31.06
78.5	47,267		0.0000	1.0000	31.06

KENTUCKY POWER COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1918-2024			EXPERIENCE BAND 1954-2024		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	46,833		0.0000	1.0000	31.06
80.5	46,511		0.0000	1.0000	31.06
81.5	46,511		0.0000	1.0000	31.06
82.5	44,627		0.0000	1.0000	31.06
83.5	44,510		0.0000	1.0000	31.06
84.5	44,080		0.0000	1.0000	31.06
85.5	43,738		0.0000	1.0000	31.06
86.5					31.06

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## **PART VIII. NET SALVAGE STATISTICS**

KENTUCKY POWER COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF MARCH 31, 2025

ACCOUNT (1)	TERMINAL RETIREMENTS		INTERIM RETIREMENTS		TOTAL NET SALVAGE		ESTIMATED NET SALVAGE (%) (10)=(9)/(9)
	RETIREMENTS (\$) (2)	NET SALVAGE (\$) (3)	RETIREMENTS (\$) (5)	NET SALVAGE (\$) (6)	NET SALVAGE (\$) (7)=(5)+(6)	TOTAL RETIREMENTS (\$) (8)=(4)+(7)	
STEAM PRODUCTION PLANT							
BIG SANDY							
311.00 STRUCTURES AND IMPROVEMENTS	22,549,391	2,085,960	2,121,317	(20)	424,263	2,510,223	(10)
312.00 BOILER PLANT EQUIPMENT	75,804,450	7,012,387	11,183,189	(30)	3,354,957	86,987,639	(12)
314.00 TURBOGENERATOR UNITS	54,567,252	5,047,813	9,893,647	(25)	2,473,412	10,367,343	(12)
315.00 ACCESSORY ELECTRIC EQUIPMENT	6,783,722	627,537	1,649,882	(10)	164,988	7,521,224	(9)
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	3,744,741	346,412	737,782	(20)	147,556	4,483,604	(11)
TOTAL BIG SANDY	163,449,555	15,120,108	25,585,616	(9)	6,565,176	21,685,284	(11)
MITCHELL							
311.00 STRUCTURES AND IMPROVEMENTS	75,448,882	10,122,896	5,843,992	(20)	1,158,798	11,291,694	(14)
312.00 BOILER PLANT EQUIPMENT	792,780,630	106,366,555	123,587,379	(30)	37,076,214	143,442,769	(16)
314.00 TURBOGENERATOR UNITS	50,456,969	6,769,758	11,361,489	(25)	2,840,372	9,610,130	(16)
315.00 ACCESSORY ELECTRIC EQUIPMENT	20,934,004	2,808,693	6,097,755	(10)	609,776	3,418,468	(13)
316.00 MISCELLANEOUS POWER PLANT EQUIPMENT	8,636,347	1,292,898	286,743	(20)	1,579,641	27,031,760	(14)
TOTAL MITCHELL	949,257,032	127,360,600	148,324,330	(13)	41,981,903	1,097,581,363	(15)
TOTAL STEAM PRODUCTION PLANT	1,112,706,587	142,480,908	173,910,147		48,547,079	191,027,987	



KENTUCKY POWER COMPANY

ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	8,355	2,407	29	2,645	32	238	3
2002	1,168	53	5	42	4	11-	1-
2003	5,061	2,154	43		0	2,154-	43-
2004	74,097	110,508	149	332	0	110,176-	149-
2005	60,910	31,351	51		0	31,351-	51-
2006	118,897	34,075	29		0	34,075-	29-
2007	258,942	121,648	47	4,018	2	117,629-	45-
2008	348,944	55,310	16	5,784	2	49,526-	14-
2009	197,473	248,365	126	33,807	17	214,558-	109-
2010	106,481	201,579	189	14,509	14	187,069-	176-
2011	36,646	4,918	13	1,044	3	3,873-	11-
2012	188,376	67,820	36	11,693	6	56,127-	30-
2013	5,457-		0		0		0
2014	665,374	218,180	33	4,432-	1-	222,612-	33-
2015	41,257	259,090	628	859	2	258,231-	626-
2016	25,715	40,651	158		0	40,651-	158-
2017	324,854	8,461	3	7,376	2	1,086-	0
2018	47,867	210,739	440	19,311	40	191,428-	400-
2019	293,176	375,903	128	200-	0	376,103-	128-
2020	58,891	629,971		50-	0	630,021-	
2021	92,908	120,176	129		0	120,176-	129-
2022	75,489	4,793	6		0	4,793-	6-
2023	37,186	72,475	195	17-	0	72,492-	195-
2024	1,842,061	138,979	8		0	138,979-	8-
TOTAL	4,904,673	2,959,605	60	96,722	2	2,862,883-	58-

THREE-YEAR MOVING AVERAGES

01-03	4,861	1,538	32	896	18	642-	13-
02-04	26,775	37,572	140	125	0	37,447-	140-
03-05	46,689	48,004	103	111	0	47,893-	103-
04-06	84,635	58,644	69	111	0	58,534-	69-
05-07	146,250	62,358	43	1,339	1	61,018-	42-
06-08	242,261	70,344	29	3,268	1	67,077-	28-
07-09	268,453	141,774	53	14,537	5	127,238-	47-
08-10	217,633	168,418	77	18,034	8	150,384-	69-
09-11	113,533	151,620	134	16,454	14	135,167-	119-
10-12	110,501	91,439	83	9,082	8	82,356-	75-
11-13	73,188	24,246	33	4,246	6	20,000-	27-
12-14	282,764	95,333	34	2,420	1	92,913-	33-
13-15	233,725	159,090	68	1,191-	1-	160,281-	69-

KENTUCKY POWER COMPANY

ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	244,116	172,640	71	1,191-	0	173,831-	71-
15-17	130,609	102,734	79	2,745	2	99,989-	77-
16-18	132,812	86,617	65	8,896	7	77,722-	59-
17-19	221,966	198,368	89	8,829	4	189,539-	85-
18-20	133,312	405,538	304	6,354	5	399,184-	299-
19-21	148,325	375,350	253	83-	0	375,433-	253-
20-22	75,763	251,647	332	17-	0	251,663-	332-
21-23	68,528	65,815	96	6-	0	65,820-	96-
22-24	651,578	72,082	11	6-	0	72,088-	11-
FIVE-YEAR AVERAGE							
20-24	421,307	193,279	46	13-	0	193,292-	46-

KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2001	356,729	102,777	29	112,928	32	10,151	3
2002	560,581	25,634	5	20,131	4	5,503-	1-
2003	15,170,924	6,455,047	43		0	6,455,047-	43-
2004	2,293,276	3,420,167	149	10,266	0	3,409,902-	149-
2005	946,348	487,092	51		0	487,092-	51-
2006	2,730,271	782,472	29		0	782,472-	29-
2007	2,668,838	1,253,787	47	41,416	2	1,212,371-	45-
2008	5,305,939	841,024	16	87,952	2	753,072-	14-
2009	3,204,443	4,030,287	126	548,597	17	3,481,690-	109-
2010	1,513,601	2,865,395	189	206,249	14	2,659,147-	176-
2011	4,675,112	627,343	13	133,220	3	494,123-	11-
2012	5,487,449	1,975,629	36	340,628	6	1,635,001-	30-
2013	1,769,543	1,021,974	58	266,522	15	755,452-	43-
2014	3,849,141	1,755,638	46	663,741	17	1,091,898-	28-
2015	17,961,893	1,200,042	7	252,600	1	947,442-	5-
2016	14,843,426	1,509,579	10	305,819	2	1,203,760-	8-
2017	2,732,544	755,586	28	238,122	9	517,465-	19-
2018	5,088,810	1,936,443	38	278,918	5	1,657,525-	33-
2019	4,719,140	791,358	17	257,676	5	533,682-	11-
2020	3,486,933	3,921,743	112	439,281	13	3,482,462-	100-
2021	1,917,658	438,116	23	1,419	0	436,697-	23-
2022	4,168,978	730,725	18	12,550-	0	743,276-	18-
2023	10,300,004	2,136,288	21	8,006-	0	2,144,293-	21-
2024	6,435,324	4,360,193	68	132,093	2	4,228,101-	66-
TOTAL	122,186,904	43,424,340	36	4,317,021	4	39,107,318-	32-

THREE-YEAR MOVING AVERAGES

01-03	5,362,745	2,194,486	41	44,353	1	2,150,133-	40-
02-04	6,008,261	3,300,283	55	10,132	0	3,290,151-	55-
03-05	6,136,849	3,454,102	56	3,422	0	3,450,680-	56-
04-06	1,989,965	1,563,244	79	3,422	0	1,559,822-	78-
05-07	2,115,152	841,117	40	13,805	1	827,312-	39-
06-08	3,568,349	959,094	27	43,123	1	915,971-	26-
07-09	3,726,406	2,041,699	55	225,988	6	1,815,711-	49-
08-10	3,341,328	2,578,902	77	280,932	8	2,297,969-	69-
09-11	3,131,052	2,507,675	80	296,022	9	2,211,653-	71-
10-12	3,892,054	1,822,789	47	226,699	6	1,596,090-	41-
11-13	3,977,368	1,208,315	30	246,790	6	961,525-	24-
12-14	3,702,044	1,584,414	43	423,630	11	1,160,783-	31-
13-15	7,860,192	1,325,885	17	394,288	5	931,597-	12-

KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	12,218,153	1,488,420	12	407,387	3	1,081,033-	9-
15-17	11,845,954	1,155,069	10	265,514	2	889,556-	8-
16-18	7,554,927	1,400,536	19	274,286	4	1,126,250-	15-
17-19	4,180,165	1,161,129	28	258,239	6	902,890-	22-
18-20	4,431,628	2,216,515	50	325,292	7	1,891,223-	43-
19-21	3,374,577	1,717,072	51	232,792	7	1,484,280-	44-
20-22	3,191,190	1,696,861	53	142,717	4	1,554,145-	49-
21-23	5,462,213	1,101,710	20	6,379-	0	1,108,088-	20-
22-24	6,968,102	2,409,069	35	37,179	1	2,371,890-	34-
FIVE-YEAR AVERAGE							
20-24	5,261,779	2,317,413	44	110,447	2	2,206,966-	42-



KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	141,367	40,729	29	44,752	32	4,023	3
2002	257,582	11,779	5	9,250	4	2,528-	1-
2003	1,427,668	607,456	43		0	607,456-	43-
2004	692,983	1,033,507	149	3,102	0	1,030,405-	149-
2005	333,750	171,784	51		0	171,784-	51-
2006	493,138	141,329	29		0	141,329-	29-
2007	884,733	415,637	47	13,730	2	401,907-	45-
2008	211,543	33,531	16	3,507	2	30,024-	14-
2009	402,511	506,245	126	68,909	17	437,336-	109-
2010	29,832	56,475	189	4,065	14	52,410-	176-
2011	242,624	32,557	13	6,914	3	25,644-	11-
2012	513,877	185,009	36	31,898	6	153,111-	30-
2013	1,598,668	923,287	58	240,786	15	682,502-	43-
2014	1,650,644	664,765	40	111,032	7	553,733-	34-
2015	1,365,107	412,025	30	2-	0	412,027-	30-
2016	365,177	368-	0	37	0	406	0
2017	327,241	30,154	9	6,992	2	23,162-	7-
2018	4,023,970	217,189	5	2,394-	0	219,583-	5-
2019	815,963	1,243,651	152		0	1,243,651-	152-
2020	386,137	42,536	11	896-	0	43,432-	11-
2021	1,324	13,444			0	13,444-	
2022	2,309	20,970	908		0	20,970-	908-
2023	1,979,284	1,127,404	57	2,274-	0	1,129,677-	57-
2024	2,235,440	1,385,217	62	3,439-	0	1,388,656-	62-
TOTAL	20,382,871	9,316,311	46	535,969	3	8,780,342-	43-

THREE-YEAR MOVING AVERAGES

01-03	608,873	219,988	36	18,001	3	201,987-	33-
02-04	792,744	550,914	69	4,117	1	546,796-	69-
03-05	818,134	604,249	74	1,034	0	603,215-	74-
04-06	506,623	448,873	89	1,034	0	447,839-	88-
05-07	570,540	242,916	43	4,577	1	238,340-	42-
06-08	529,804	196,832	37	5,745	1	191,087-	36-
07-09	499,596	318,471	64	28,715	6	289,756-	58-
08-10	214,628	198,750	93	25,494	12	173,257-	81-
09-11	224,989	198,426	88	26,629	12	171,796-	76-
10-12	262,111	91,347	35	14,292	5	77,055-	29-
11-13	785,056	380,285	48	93,199	12	287,085-	37-
12-14	1,254,396	591,020	47	127,905	10	463,115-	37-
13-15	1,538,140	666,692	43	117,272	8	549,421-	36-

KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	1,126,976	358,807	32	37,022	3	321,785-	29-
15-17	685,841	147,270	21	2,342	0	144,928-	21-
16-18	1,572,129	82,325	5	1,545	0	80,780-	5-
17-19	1,722,391	496,998	29	1,533	0	495,465-	29-
18-20	1,742,023	501,125	29	1,097-	0	502,222-	29-
19-21	401,141	433,210	108	299-	0	433,509-	108-
20-22	129,923	25,650	20	299-	0	25,949-	20-
21-23	660,972	387,273	59	758-	0	388,030-	59-
22-24	1,405,678	844,530	60	1,904-	0	846,434-	60-
FIVE-YEAR AVERAGE							
20-24	920,899	517,914	56	1,322-	0	519,236-	56-

KENTUCKY POWER COMPANY

ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	32,876	9,472	29	10,407	32	935	3
2002	2,009	92	5	72	4	20-	1-
2003	587,860	250,127	43		0	250,127-	43-
2004	4,041	6,027	149	18	0	6,009-	149-
2005	12,798	6,587	51		0	6,587-	51-
2006	57,499	16,479	29		0	16,479-	29-
2007	46,468	21,830	47	721	2	21,109-	45-
2008	16,287	2,582	16	270	2	2,312-	14-
2009	92,613	116,482	126	15,855	17	100,626-	109-
2010	8,326	15,762	189	1,135	14	14,627-	176-
2011	70,610	9,475	13	2,012	3	7,463-	11-
2012	133,162	47,942	36	8,266	6	39,676-	30-
2013	9,007	5,202	58	1,357	15	3,845-	43-
2014	5,430	36,162	666	29,389	541	6,773-	125-
2015	1,446		0	1,052	73	1,052	73
2016	62,139	6,502	10	7,321	12	818	1
2017	43,715	3,705	8		0	3,705-	8-
2018	81,938	81,082	99		0	81,082-	99-
2019	296,675	37,646	13	100-	0	37,747-	13-
2020	74,839	45,095	60	6,000	8	39,095-	52-
2021	151,775	19,640	13	146-	0	19,786-	13-
2022	157,562	106,360	68	10,000	6	96,360-	61-
2023	45,736	26,676	58	1,417-	3-	28,093-	61-
2024	144,603	254,721	176	264-	0	254,985-	176-
TOTAL	2,139,415	1,125,649	53	91,947	4	1,033,702-	48-

THREE-YEAR MOVING AVERAGES

01-03	207,582	86,564	42	3,493	2	83,071-	40-
02-04	197,970	85,415	43	30	0	85,385-	43-
03-05	201,566	87,581	43	6	0	87,575-	43-
04-06	24,779	9,698	39	6	0	9,692-	39-
05-07	38,922	14,965	38	240	1	14,725-	38-
06-08	40,085	13,630	34	330	1	13,300-	33-
07-09	51,790	46,965	91	5,615	11	41,349-	80-
08-10	39,076	44,942	115	5,753	15	39,188-	100-
09-11	57,183	47,239	83	6,334	11	40,906-	72-
10-12	70,699	24,393	35	3,804	5	20,589-	29-
11-13	70,926	20,873	29	3,878	5	16,995-	24-
12-14	49,200	29,768	61	13,004	26	16,765-	34-
13-15	5,294	13,788	260	10,599	200	3,189-	60-

KENTUCKY POWER COMPANY

ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	23,005	14,221	62	12,587	55	1,634-	7-
15-17	35,767	3,403	10	2,791	8	612-	2-
16-18	62,597	30,430	49	2,440	4	27,990-	45-
17-19	140,776	40,811	29	33-	0	40,845-	29-
18-20	151,151	54,608	36	1,967	1	52,641-	35-
19-21	174,430	34,127	20	1,918	1	32,209-	18-
20-22	128,059	57,032	45	5,285	4	51,747-	40-
21-23	118,358	50,892	43	2,812	2	48,080-	41-
22-24	115,967	129,253	111	2,773	2	126,480-	109-
FIVE-YEAR AVERAGE							
20-24	114,903	90,499	79	2,835	2	87,664-	76-

KENTUCKY POWER COMPANY

ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	4,332	1,248	29	1,371	32	123	3
2002	38,540	1,762	5	1,384	4	378-	1-
2003	62,105	26,425	43		0	26,425-	43-
2004	64,450	96,119	149	288	0	95,831-	149-
2005	31,593	16,261	51		0	16,261-	51-
2006	20,681	5,927	29		0	5,927-	29-
2007	15,563	7,311	47	242	2	7,070-	45-
2008	25,877	4,102	16	429	2	3,673-	14-
2009	69,958	87,988	126	11,977	17	76,011-	109-
2010	9,951	18,838	189	1,356	14	17,482-	176-
2011	50,251	6,743	13	1,432	3	5,311-	11-
2012	19,533	7,032	36	1,212	6	5,820-	30-
2013	13,990	8,080	58	2,107	15	5,973-	43-
2014	2,516	1,006	40	160	6	846-	34-
2015	118	70,134-		123	104	70,257	
2016	12,865	2,712	21	2,000	16	712-	6-
2017	29,473	2,672	9		0	2,672-	9-
2018	32,892	24,764	75		0	24,764-	75-
2019	33,826	247,288	731	37,500	111	209,788-	620-
2020	38,460	188,532	490	2,107	5	186,426-	485-
2021	34,252	87,612	256	4,556	13	83,057-	242-
2022	23,984	82	0		0	82-	0
2023	2,076	23,464			0	23,464-	
2024	87,427	36,004	41	2,075-	2-	38,079-	44-
TOTAL	724,712	831,839	115	66,168	9	765,671-	106-

THREE-YEAR MOVING AVERAGES

01-03	34,992	9,812	28	918	3	8,893-	25-
02-04	55,032	41,436	75	558	1	40,878-	74-
03-05	52,716	46,268	88	96	0	46,172-	88-
04-06	38,908	39,436	101	96	0	39,340-	101-
05-07	22,612	9,833	43	80	0	9,753-	43-
06-08	20,707	5,780	28	223	1	5,556-	27-
07-09	37,133	33,134	89	4,216	11	28,918-	78-
08-10	35,262	36,976	105	4,587	13	32,389-	92-
09-11	43,387	37,856	87	4,922	11	32,935-	76-
10-12	26,578	10,871	41	1,333	5	9,538-	36-
11-13	27,925	7,285	26	1,584	6	5,701-	20-
12-14	12,013	5,373	45	1,160	10	4,213-	35-
13-15	5,541	20,349-	367-	797	14	21,146	382

KENTUCKY POWER COMPANY

ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	5,166	22,139-	429-	761	15	22,900	443
15-17	14,152	21,583-	153-	708	5	22,291	158
16-18	25,077	10,049	40	667	3	9,383-	37-
17-19	32,064	91,575	286	12,500	39	79,075-	247-
18-20	35,059	153,528	438	13,202	38	140,326-	400-
19-21	35,512	174,477	491	14,721	41	159,757-	450-
20-22	32,232	92,076	286	2,221	7	89,855-	279-
21-23	20,104	37,053	184	1,518	8	35,534-	177-
22-24	37,829	19,850	52	692-	2-	20,542-	54-
FIVE-YEAR AVERAGE							
20-24	37,240	67,139	180	917	2	66,221-	178-

KENTUCKY POWER COMPANY  
ACCOUNT 350.10 LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2005	1		0		0		0
2006							
2007							
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
TOTAL	1		0		0		0

THREE-YEAR MOVING AVERAGES

05-07		0		0		0
06-08						
07-09						
08-10						
09-11						
10-12						
11-13						
12-14						
13-15						
14-16						
15-17						
16-18						
17-19						
18-20						
19-21						
20-22						

KENTUCKY POWER COMPANY

ACCOUNT 350.10 LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR	COST OF		GROSS		NET	
	RETIREMENTS	REMOVAL		SALVAGE		SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
	21-23						
	22-24						
FIVE-YEAR AVERAGE							
	20-24						



KENTUCKY POWER COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	852	15,675		72	8	15,603-	
2002	352	3,491	992		0	3,491-	992-
2003							
2004		308-				308	
2005	57,776	1,385	2		0	1,385-	2-
2006		3,596				3,596-	
2007	2,382		0		0		0
2008	8,548	79	1		0	79-	1-
2009	4,065	1,405	35	39-	1-	1,444-	36-
2010	8,076	160	2		0	160-	2-
2011	6,050	770	13		0	770-	13-
2012							
2013	6,195	293	5	578	9	285	5
2014							
2015	16,411		0		0		0
2016	42,724		0		0		0
2017	56,694		0		0		0
2018	659,218	58,614	9	9	0	58,605-	9-
2019	31,828	4,195	13		0	4,195-	13-
2020	64,074	216,100	337	22,257	35	193,843-	303-
2021	296,790	3,722	1		0	3,722-	1-
2022	1,778	63,811		190	11	63,621-	
2023	6,770	176,781		7,668	113	169,113-	
2024	88,560	3,456	4		0	3,456-	4-
TOTAL	1,359,143	553,223	41	30,735	2	522,488-	38-

THREE-YEAR MOVING AVERAGES

01-03	401	6,389		24	6	6,365-	
02-04	117	1,061	904		0	1,061-	904-
03-05	19,259	359	2		0	359-	2-
04-06	19,259	1,558	8		0	1,558-	8-
05-07	20,053	1,660	8		0	1,660-	8-
06-08	3,643	1,225	34		0	1,225-	34-
07-09	4,998	495	10	13-	0	508-	10-
08-10	6,896	548	8	13-	0	561-	8-
09-11	6,063	778	13	13-	0	791-	13-
10-12	4,708	310	7		0	310-	7-
11-13	4,082	354	9	193	5	161-	4-
12-14	2,065	98	5	193	9	95	5
13-15	7,535	98	1	193	3	95	1

KENTUCKY POWER COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	19,712		0		0		0
15-17	38,610		0		0		0
16-18	252,879	19,538	8	3	0	19,535-	8-
17-19	249,247	20,936	8	3	0	20,933-	8-
18-20	251,707	92,970	37	7,422	3	85,547-	34-
19-21	130,898	74,672	57	7,419	6	67,253-	51-
20-22	120,881	94,544	78	7,482	6	87,062-	72-
21-23	101,779	81,438	80	2,619	3	78,819-	77-
22-24	32,369	81,349	251	2,619	8	78,730-	243-
FIVE-YEAR AVERAGE							
20-24	91,594	92,774	101	6,023	7	86,751-	95-

KENTUCKY POWER COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	308,530	25,232	8	433	0	24,800-	8-
2001	104,157	114,605	110	52,176	50	62,429-	60-
2002	167,185	36,758	22	31,282	19	5,476-	3-
2003	462,374	194,851	42	296,619	64	101,768	22
2004	699,507	114,910	16	128,691	18	13,781	2
2005	687,092	130,806	19		0	130,806-	19-
2006	783,966	55,897	7		0	55,897-	7-
2007	298,346	184,315	62	4,860	2	179,455-	60-
2008	1,369,349	137,153	10	6,012-	0	143,165-	10-
2009	538,747	123,317	23	5,628	1	117,689-	22-
2010	2,154,456	118,691	6	16,257	1	102,435-	5-
2011	1,489,875	209,091	14	118,450	8	90,640-	6-
2012	1,197,113	101,782	9	37,807	3	63,974-	5-
2013	4,697,632	221,908	5	438,128	9	216,221	5
2014	353,333	1,493,562	423	320,033	91	1,173,529-	332-
2015	1,567,440	50,517	3	3,085-	0	53,602-	3-
2016	1,599,042	197,103	12	2,325	0	194,778-	12-
2017	4,809,006	331,594	7	5,945	0	325,649-	7-
2018	3,371,640	2,048,268	61	893,150	26	1,155,117-	34-
2019	623,498	104,844	17	12,761	2	92,083-	15-
2020	2,083,632	978,569	47	392,822	19	585,748-	28-
2021							
2022	1,355,823	709,151	52	81,082	6	628,069-	46-
2023	406,077	502,662	124	26,417	7	476,245-	117-
2024	1,858,647	736,148	40	17,826	1	718,322-	39-
TOTAL	32,986,468	8,921,734	27	2,873,596	9	6,048,138-	18-

THREE-YEAR MOVING AVERAGES

00-02	193,291	58,865	30	27,963	14	30,902-	16-
01-03	244,572	115,405	47	126,692	52	11,288	5
02-04	443,022	115,506	26	152,197	34	36,691	8
03-05	616,324	146,856	24	141,770	23	5,085-	1-
04-06	723,522	100,537	14	42,897	6	57,640-	8-
05-07	589,801	123,673	21	1,620	0	122,053-	21-
06-08	817,220	125,788	15	384-	0	126,172-	15-
07-09	735,481	148,262	20	1,492	0	146,770-	20-
08-10	1,354,184	126,387	9	5,291	0	121,096-	9-
09-11	1,394,359	150,366	11	46,778	3	103,588-	7-
10-12	1,613,815	143,188	9	57,505	4	85,683-	5-
11-13	2,461,540	177,593	7	198,129	8	20,535	1

KENTUCKY POWER COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	2,082,693	605,751	29	265,323	13	340,428-	16-
13-15	2,206,135	588,662	27	251,692	11	336,970-	15-
14-16	1,173,272	580,394	49	106,424	9	473,970-	40-
15-17	2,658,496	193,071	7	1,728	0	191,343-	7-
16-18	3,259,896	858,988	26	300,474	9	558,515-	17-
17-19	2,934,715	828,235	28	303,952	10	524,283-	18-
18-20	2,026,257	1,043,894	52	432,911	21	610,983-	30-
19-21	902,377	361,138	40	135,194	15	225,943-	25-
20-22	1,146,485	562,574	49	157,968	14	404,606-	35-
21-23	587,300	403,938	69	35,833	6	368,105-	63-
22-24	1,206,849	649,320	54	41,775	3	607,545-	50-
FIVE-YEAR AVERAGE							
20-24	1,140,836	585,306	51	103,629	9	481,677-	42-

KENTUCKY POWER COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	405	1,928	476	13,033		11,105	
2002	4,473	999	22		0	999-	22-
2003	2,124	47,471			0	47,471-	
2004							
2005	36,676		0		0		0
2006	20,749		0		0		0
2007		17,761				17,761-	
2008	646		0		0		0
2009	99,957	3,254	3	2-	0	3,256-	3-
2010	3,943	22,500	571	3,125	79	19,375-	491-
2011	14,361	4,381	31		0	4,381-	31-
2012	675,190	1,842,777	273	10,604	2	1,832,173-	271-
2013							
2014							
2015	56,308	20,882	37		0	20,882-	37-
2016							
2017	98,711	18,419	19		0	18,419-	19-
2018	349,791	322,699	92		0	322,699-	92-
2019	287,714	1,017,667	354		0	1,017,667-	354-
2020	32,336	34,416	106		0	34,416-	106-
2021	261,892	30,937	12		0	30,937-	12-
2022	96,178	342,967	357		0	342,967-	357-
2023	264,101	86,583	33		0	86,583-	33-
2024	118,653	16,409	14		0	16,409-	14-
TOTAL	2,424,206	3,832,050	158	26,759	1	3,805,291-	157-

THREE-YEAR MOVING AVERAGES

01-03	2,334	16,799	720	4,344	186	12,455-	534-
02-04	2,199	16,157	735		0	16,157-	735-
03-05	12,933	15,824	122		0	15,824-	122-
04-06	19,142		0		0		0
05-07	19,142	5,920	31		0	5,920-	31-
06-08	7,132	5,920	83		0	5,920-	83-
07-09	33,534	7,005	21	1-	0	7,006-	21-
08-10	34,849	8,585	25	1,041	3	7,544-	22-
09-11	39,420	10,045	25	1,041	3	9,004-	23-
10-12	231,164	623,219	270	4,576	2	618,643-	268-
11-13	229,850	615,719	268	3,534	2	612,185-	266-
12-14	225,063	614,259	273	3,534	2	610,724-	271-
13-15	18,769	6,961	37		0	6,961-	37-

KENTUCKY POWER COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	18,769	6,961	37		0	6,961-	37-
15-17	51,673	13,100	25		0	13,100-	25-
16-18	149,500	113,706	76		0	113,706-	76-
17-19	245,405	452,928	185		0	452,928-	185-
18-20	223,280	458,261	205		0	458,261-	205-
19-21	193,981	361,007	186		0	361,007-	186-
20-22	130,135	136,107	105		0	136,107-	105-
21-23	207,390	153,496	74		0	153,496-	74-
22-24	159,644	148,653	93		0	148,653-	93-
FIVE-YEAR AVERAGE							
20-24	154,632	102,262	66		0	102,262-	66-

KENTUCKY POWER COMPANY

ACCOUNT 355.00 POLES AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	380,241	83,487	22	10,983	3	72,504-	19-
2001	129,176	450,305	349	27,458	21	422,847-	327-
2002	169,001	7,407	4		0	7,407-	4-
2003	23,421	653,367		9,326	40	644,040-	
2004	358,451	76,281	21	276	0	76,005-	21-
2005	45,454	44,784	99	109	0	44,676-	98-
2006	267,008	61,071	23	1,463	1	59,608-	22-
2007	147,838	82,184	56	23,984-	16-	106,168-	72-
2008	331,274	36,078	11	2,345-	1-	38,424-	12-
2009	192,107	35,779	19	318-	0	36,097-	19-
2010	34,442	66,907	194	12,932	38	53,975-	157-
2011	263,023	6,925	3		0	6,925-	3-
2012	553,877	105,880	19	3,786	1	102,094-	18-
2013	52,616	2,486	5	4,907	9	2,422	5
2014	330,924	159,964	48	245-	0	160,208-	48-
2015	499,646	264,037	53	46-	0	264,083-	53-
2016	489,180	150,892	31		0	150,892-	31-
2017	306,122	5,533	2		0	5,533-	2-
2018	383,067	105,299	27	2,695	1	102,603-	27-
2019	446,685	273,716	61		0	273,716-	61-
2020	739,952	77,152	10	7,850	1	69,302-	9-
2021	2,145,188	1,333,791	62	7,544	0	1,326,247-	62-
2022	623,594	557,331	89		0	557,331-	89-
2023	1,761,678	275,447	16		0	275,447-	16-
2024	3,250,705	52,097	2		0	52,097-	2-
TOTAL	13,924,669	4,968,197	36	62,391	0	4,905,806-	35-

THREE-YEAR MOVING AVERAGES

00-02	226,139	180,400	80	12,814	6	167,586-	74-
01-03	107,199	370,359	345	12,262	11	358,098-	334-
02-04	183,624	245,685	134	3,201	2	242,484-	132-
03-05	142,442	258,144	181	3,237	2	254,907-	179-
04-06	223,638	60,712	27	616	0	60,096-	27-
05-07	153,433	62,680	41	7,471-	5-	70,151-	46-
06-08	248,707	59,778	24	8,289-	3-	68,067-	27-
07-09	223,740	51,347	23	8,882-	4-	60,230-	27-
08-10	185,941	46,255	25	3,423	2	42,832-	23-
09-11	163,190	36,537	22	4,205	3	32,332-	20-
10-12	283,781	59,904	21	5,572	2	54,331-	19-
11-13	289,839	38,430	13	2,898	1	35,532-	12-

KENTUCKY POWER COMPANY

ACCOUNT 355.00 POLES AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	312,473	89,443	29	2,816	1	86,627-	28-
13-15	294,395	142,162	48	1,539	1	140,623-	48-
14-16	439,916	191,631	44	97-	0	191,728-	44-
15-17	431,649	140,154	32	15-	0	140,169-	32-
16-18	392,790	87,241	22	898	0	86,343-	22-
17-19	378,625	128,182	34	898	0	127,284-	34-
18-20	523,235	152,055	29	3,515	1	148,540-	28-
19-21	1,110,609	561,553	51	5,131	0	556,422-	50-
20-22	1,169,578	656,091	56	5,131	0	650,960-	56-
21-23	1,510,153	722,190	48	2,515	0	719,675-	48-
22-24	1,878,659	294,958	16		0	294,958-	16-
FIVE-YEAR AVERAGE							
20-24	1,704,223	459,164	27	3,079	0	456,085-	27-



KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	112,146	37,040	33	4,330	4	32,710-	29-
2001	8,636	202,619		8,869	103	193,750-	
2002	107,844		0		0		0
2003	102,595	17,030	17		0	17,030-	17-
2004	55,180	28,266	51		0	28,266-	51-
2005	35,213		0		0		0
2006	126,720	21,421	17	144,620	114	123,199	97
2007	2,896	8,587	296	105,601-		114,188-	
2008	149,255	3,202	2	1,276-	1-	4,479-	3-
2009	39,790	2,230	6	1-	0	2,230-	6-
2010		15,499		8,311		7,188-	
2011	1,055		0		0		0
2012	313,102	3,116	1	313	0	2,802-	1-
2013	6,209	293	5	579	9	286	5
2014	27,875	655,848		97-	0	655,945-	
2015	36,007	56,586	157		0	56,586-	157-
2016	224,102	9,231	4		0	9,231-	4-
2017	15,455	2,566	17		0	2,566-	17-
2018	44,289	77,248	174	2,744	6	74,503-	168-
2019	269,390	34,773	13		0	34,773-	13-
2020	210,533	24,141	11		0	24,141-	11-
2021	755,522	693,145	92		0	693,145-	92-
2022	338,306	468,141	138		0	468,141-	138-
2023	34,615	584,345			0	584,345-	
2024	272,123	36,183	13		0	36,183-	13-
TOTAL	3,288,859	2,981,508	91	62,791	2	2,918,718-	89-

THREE-YEAR MOVING AVERAGES

00-02	76,209	79,886	105	4,399	6	75,487-	99-
01-03	73,025	73,216	100	2,956	4	70,260-	96-
02-04	88,540	15,099	17		0	15,099-	17-
03-05	64,329	15,099	23		0	15,099-	23-
04-06	72,371	16,562	23	48,207	67	31,644	44
05-07	54,943	10,002	18	13,006	24	3,004	5
06-08	92,957	11,070	12	12,581	14	1,511	2
07-09	63,980	4,673	7	35,626-	56-	40,299-	63-
08-10	63,015	6,977	11	2,345	4	4,632-	7-
09-11	13,615	5,909	43	2,770	20	3,140-	23-
10-12	104,719	6,205	6	2,875	3	3,330-	3-
11-13	106,789	1,136	1	297	0	839-	1-

KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	115,729	219,752	190	265	0	219,487-	190-
13-15	23,364	237,576		161	1	237,415-	
14-16	95,995	240,555	251	32-	0	240,587-	251-
15-17	91,855	22,794	25		0	22,794-	25-
16-18	94,615	29,681	31	915	1	28,767-	30-
17-19	109,711	38,195	35	915	1	37,281-	34-
18-20	174,737	45,387	26	915	1	44,472-	25-
19-21	411,815	250,686	61		0	250,686-	61-
20-22	434,787	395,142	91		0	395,142-	91-
21-23	376,148	581,877	155		0	581,877-	155-
22-24	215,015	362,890	169		0	362,890-	169-
FIVE-YEAR AVERAGE							
20-24	322,220	361,191	112		0	361,191-	112-

KENTUCKY POWER COMPANY  
ACCOUNT 360.10 LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004		2,814				2,814-	
2005							
2006							
2007	1	80,271			0	80,271-	
2008							
2009		144,283				144,283-	
2010							
2011							
2012		40,560				40,560-	
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
TOTAL	1	267,929			0	267,929-	

THREE-YEAR MOVING AVERAGES

04-06	938		938-
05-07	26,757	0	26,757-
06-08	26,757	0	26,757-
07-09	74,851	0	74,851-
08-10	48,094		48,094-
09-11	48,094		48,094-
10-12	13,520		13,520-
11-13	13,520		13,520-
12-14	13,520		13,520-
13-15			
14-16			
15-17			
16-18			
17-19			
18-20			
19-21			

KENTUCKY POWER COMPANY

ACCOUNT 360.10 LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
	20-22						
	21-23						
	22-24						
FIVE-YEAR AVERAGE							
	20-24						

KENTUCKY POWER COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001		4,367		172		4,195-	
2002		270		1,790		1,520	
2003							
2004	370	262	71		0	262-	71-
2005	25,016	398	2		0	398-	2-
2006							
2007							
2008	206	1,234	599		0	1,234-	599-
2009	17,511	27,306	156	2,417	14	24,889-	142-
2010	15,897	280	2		0	280-	2-
2011	1,088		0		0		0
2012		3,338				3,338-	
2013	9,424	4,190	44	1,472	16	2,718-	29-
2014							
2015							
2016	14,030		0		0		0
2017	29,600		0		0		0
2018	598	73,338			0	73,338-	
2019	55,517	65,368	118		0	65,368-	118-
2020	23,263	42,258	182		0	42,258-	182-
2021	56,695	6,335	11		0	6,335-	11-
2022		10,133		1,980		8,152-	
2023		20,518		1,885		18,633-	
2024	1,483		0		0		0
TOTAL	250,697	259,596	104	9,716	4	249,880-	100-

THREE-YEAR MOVING AVERAGES

01-03		1,545		654		892-	
02-04	123	177	144	597	483	419	340
03-05	8,462	220	3		0	220-	3-
04-06	8,462	220	3		0	220-	3-
05-07	8,339	133	2		0	133-	2-
06-08	69	411	599		0	411-	599-
07-09	5,906	9,513	161	806	14	8,708-	147-
08-10	11,205	9,607	86	806	7	8,801-	79-
09-11	11,499	9,195	80	806	7	8,390-	73-
10-12	5,662	1,206	21		0	1,206-	21-
11-13	3,504	2,509	72	491	14	2,019-	58-
12-14	3,141	2,509	80	491	16	2,019-	64-
13-15	3,141	1,397	44	491	16	906-	29-

KENTUCKY POWER COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	4,677		0		0		0
15-17	14,543		0		0		0
16-18	14,742	24,446	166		0	24,446-	166-
17-19	28,572	46,236	162		0	46,236-	162-
18-20	26,459	60,322	228		0	60,322-	228-
19-21	45,158	37,987	84		0	37,987-	84-
20-22	26,652	19,576	73	660	2	18,915-	71-
21-23	18,898	12,329	65	1,288	7	11,040-	58-
22-24	494	10,217		1,288	261	8,928-	
FIVE-YEAR AVERAGE							
20-24	16,288	15,849	97	773	5	15,076-	93-

KENTUCKY POWER COMPANY  
ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	430,935	22,113	5	148,214	34	126,101	29
2001	543,501	91,193	17	311,661	57	220,469	41
2002	163,286	16,260	10	5,487	3	10,773-	7-
2003	448,922	35,932	8	20,657	5	15,274-	3-
2004	325,880	298,344	92	36,543	11	261,801-	80-
2005	1,290,673	72,470	6		0	72,470-	6-
2006	854,862	208,222	24	18,971	2	189,252-	22-
2007	811,722	39,121	5	223,230	28	184,109	23
2008	197,774	75,602	38	10,209	5	65,394-	33-
2009	895,212	208,586	23	49,647	6	158,939-	18-
2010	268,629	89,564	33	16,253	6	73,311-	27-
2011	1,480,852	65,084	4	8,820	1	56,265-	4-
2012	1,141,864	189,771	17	68,124	6	121,647-	11-
2013	1,091,672	485,380	44	170,516	16	314,863-	29-
2014	653,949	111,697	17	8,623	1	103,074-	16-
2015	273,492	147,720	54	155,966	57	8,246	3
2016	269,238	22,804	8		0	22,804-	8-
2017	743,059	127,913	17	1,875	0	126,038-	17-
2018	1,366,804	231,094	17	1,975	0	229,119-	17-
2019	1,559,127	128,912	8		0	128,912-	8-
2020	1,274,077	380,117	30	4,170	0	375,947-	30-
2021	1,121,300	81,324	7	10,000	1	71,324-	6-
2022	1,278,195	202,512	16	19,784	2	182,728-	14-
2023	357,071	150,140	42	9,858	3	140,282-	39-
2024	895,078	115,177	13		0	115,177-	13-
TOTAL	19,737,175	3,597,049	18	1,300,583	7	2,296,466-	12-

THREE-YEAR MOVING AVERAGES

00-02	379,241	43,188	11	155,121	41	111,932	30
01-03	385,237	47,795	12	112,602	29	64,807	17
02-04	312,696	116,845	37	20,896	7	95,949-	31-
03-05	688,492	135,582	20	19,067	3	116,515-	17-
04-06	823,805	193,012	23	18,505	2	174,508-	21-
05-07	985,752	106,604	11	80,733	8	25,871-	3-
06-08	621,453	107,648	17	84,136	14	23,512-	4-
07-09	634,903	107,770	17	94,362	15	13,408-	2-
08-10	453,872	124,584	27	25,369	6	99,214-	22-
09-11	881,565	121,078	14	24,907	3	96,171-	11-
10-12	963,782	114,806	12	31,066	3	83,741-	9-
11-13	1,238,129	246,745	20	82,487	7	164,258-	13-

KENTUCKY POWER COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	962,495	262,283	27	82,421	9	179,861-	19-
13-15	673,038	248,266	37	111,702	17	136,564-	20-
14-16	398,893	94,074	24	54,863	14	39,210-	10-
15-17	428,596	99,479	23	52,614	12	46,865-	11-
16-18	793,034	127,270	16	1,283	0	125,987-	16-
17-19	1,222,997	162,639	13	1,283	0	161,356-	13-
18-20	1,400,003	246,708	18	2,048	0	244,659-	17-
19-21	1,318,168	196,784	15	4,723	0	192,061-	15-
20-22	1,224,524	221,317	18	11,318	1	210,000-	17-
21-23	918,855	144,659	16	13,214	1	131,445-	14-
22-24	843,448	155,943	18	9,881	1	146,062-	17-
FIVE-YEAR AVERAGE							
20-24	985,144	185,854	19	8,762	1	177,092-	18-



KENTUCKY POWER COMPANY

ACCOUNT 364.00 POLES AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	1,459,576	320,750	22	139,744	10	181,006-	12-
2001	1,402,184	624,110	45	246,887	18	377,223-	27-
2002	46,842	341,683	729	85,547	183	256,136-	547-
2003	770,546	239,438	31	154,312	20	85,126-	11-
2004	3,264,700	828,507	25	29,790	1	798,717-	24-
2005	728,627	347,205	48	53,183	7	294,022-	40-
2006	839,957	591,822	70	77,574	9	514,248-	61-
2007	1,283,667	830,071	65	92,841	7	737,230-	57-
2008	1,315,032	912,666	69	110,909	8	801,757-	61-
2009	1,458,857	1,139,432	78	200,635	14	938,797-	64-
2010	1,379,987	1,146,537	83	98,567	7	1,047,970-	76-
2011	918,787	664,553	72	44,771	5	619,782-	67-
2012	946,893	612,555	65	37,126	4	575,429-	61-
2013	972,449	432,371	44	151,894	16	280,477-	29-
2014	1,008,623	790,118	78	48,374	5	741,745-	74-
2015	1,336,457	980,301	73	59,211	4	921,090-	69-
2016	1,685,487	929,218	55	30,198	2	899,020-	53-
2017	1,818,711	946,232	52	60,771	3	885,461-	49-
2018	2,225,132	1,152,890	52	64,134	3	1,088,756-	49-
2019	2,093,613	1,632,742	78	88,027	4	1,544,715-	74-
2020	1,743,129	1,421,138	82	33,861	2	1,387,277-	80-
2021	1,911,401	1,838,628	96	39,090	2	1,799,538-	94-
2022	2,166,659	1,965,006	91	17,153	1	1,947,854-	90-
2023	1,984,051	1,474,197	74	1,244-	0	1,475,441-	74-
2024	1,657,504	1,285,748	78	27,430	2	1,258,318-	76-
TOTAL	36,418,869	23,447,917	64	1,990,783	5	21,457,135-	59-

THREE-YEAR MOVING AVERAGES

00-02	969,534	428,848	44	157,392	16	271,455-	28-
01-03	739,857	401,743	54	162,248	22	239,495-	32-
02-04	1,360,696	469,876	35	89,883	7	379,993-	28-
03-05	1,587,958	471,717	30	79,095	5	392,622-	25-
04-06	1,611,095	589,178	37	53,516	3	535,663-	33-
05-07	950,750	589,699	62	74,533	8	515,167-	54-
06-08	1,146,219	778,186	68	93,774	8	684,412-	60-
07-09	1,352,519	960,723	71	134,795	10	825,928-	61-
08-10	1,384,625	1,066,211	77	136,704	10	929,508-	67-
09-11	1,252,544	983,507	79	114,658	9	868,849-	69-
10-12	1,081,889	807,882	75	60,155	6	747,727-	69-
11-13	946,043	569,826	60	77,930	8	491,896-	52-

KENTUCKY POWER COMPANY

ACCOUNT 364.00 POLES AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	975,988	611,681	63	79,131	8	532,550-	55-
13-15	1,105,843	734,263	66	86,493	8	647,771-	59-
14-16	1,343,522	899,879	67	45,928	3	853,952-	64-
15-17	1,613,551	951,917	59	50,060	3	901,857-	56-
16-18	1,909,776	1,009,447	53	51,701	3	957,746-	50-
17-19	2,045,818	1,243,955	61	70,977	3	1,172,978-	57-
18-20	2,020,624	1,402,257	69	62,007	3	1,340,250-	66-
19-21	1,916,047	1,630,836	85	53,659	3	1,577,177-	82-
20-22	1,940,396	1,741,591	90	30,035	2	1,711,556-	88-
21-23	2,020,704	1,759,277	87	18,333	1	1,740,944-	86-
22-24	1,936,071	1,574,984	81	14,446	1	1,560,538-	81-
FIVE-YEAR AVERAGE							
20-24	1,892,549	1,596,943	84	23,258	1	1,573,685-	83-

KENTUCKY POWER COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	1,553,565	245,459	16	377,957	24	132,498	9
2001	1,323,285	506,462	38	893,879	68	387,417	29
2002	2,020,300	324,713	16	1,187,537	59	862,824	43
2003	1,665,159	321,313	19	751,432	45	430,120	26
2004	1,048,651	330,745	32	777,483	74	446,738	43
2005	1,665,652	182,308-	11-	12,793	1	195,100	12
2006	2,373,219	108,564	5	596,840	25	488,277	21
2007	2,993,281	816,672	27	380,715	13	435,956-	15-
2008	3,155,687	936,551	30	670,173	21	266,378-	8-
2009	4,155,157	868,823	21	967,544	23	98,721	2
2010	2,211,003	751,951	34	637,246	29	114,705-	5-
2011	1,916,866	620,955	32	567,691	30	53,263-	3-
2012	2,784,176	1,355,403	49	802,599	29	552,804-	20-
2013	2,908,748	1,293,288	44	454,339	16	838,950-	29-
2014	2,198,878	890,148	40	703,061	32	187,088-	9-
2015	2,195,251	1,082,027	49	419,353	19	662,675-	30-
2016	2,310,553	972,278	42	339,732	15	632,547-	27-
2017	2,141,579	980,056	46	243,880	11	736,176-	34-
2018	2,807,217	1,058,324	38	300,981	11	757,343-	27-
2019	3,377,971	1,461,157	43	529,327	16	931,830-	28-
2020	1,995,524	1,356,165	68	261,691	13	1,094,475-	55-
2021	2,175,702	1,653,111	76	178,713	8	1,474,398-	68-
2022	2,063,298	1,741,961	84	33,374	2	1,708,587-	83-
2023	1,961,826	1,506,599	77	9,694	0	1,496,905-	76-
2024	1,468,727	1,239,625	84	206,068	14	1,033,557-	70-
TOTAL	56,471,276	22,240,044	39	12,304,102	22	9,935,942-	18-

THREE-YEAR MOVING AVERAGES

00-02	1,632,383	358,878	22	819,791	50	460,913	28
01-03	1,669,581	384,163	23	944,283	57	560,120	34
02-04	1,578,037	325,590	21	905,484	57	579,894	37
03-05	1,459,821	156,583	11	513,903	35	357,319	24
04-06	1,695,841	85,667	5	462,372	27	376,705	22
05-07	2,344,051	247,642	11	330,116	14	82,474	4
06-08	2,840,729	620,595	22	549,243	19	71,353-	3-
07-09	3,434,708	874,015	25	672,811	20	201,204-	6-
08-10	3,173,949	852,442	27	758,321	24	94,121-	3-
09-11	2,761,009	747,243	27	724,161	26	23,082-	1-
10-12	2,304,015	909,436	39	669,179	29	240,257-	10-
11-13	2,536,597	1,089,882	43	608,210	24	481,672-	19-

KENTUCKY POWER COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	2,630,601	1,179,613	45	653,333	25	526,280-	20-
13-15	2,434,293	1,088,488	45	525,584	22	562,904-	23-
14-16	2,234,894	981,485	44	487,382	22	494,103-	22-
15-17	2,215,794	1,011,454	46	334,321	15	677,132-	31-
16-18	2,419,783	1,003,553	41	294,864	12	708,688-	29-
17-19	2,775,589	1,166,512	42	358,063	13	808,450-	29-
18-20	2,726,904	1,291,882	47	364,000	13	927,883-	34-
19-21	2,516,399	1,490,145	59	323,244	13	1,166,901-	46-
20-22	2,078,175	1,583,746	76	157,926	8	1,425,820-	69-
21-23	2,066,942	1,633,890	79	73,927	4	1,559,963-	75-
22-24	1,831,284	1,496,062	82	83,045	5	1,413,016-	77-
FIVE-YEAR AVERAGE							
20-24	1,933,015	1,499,492	78	137,908	7	1,361,584-	70-

KENTUCKY POWER COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	6,479	3,461	53	651	10	2,810-	43-
2001	9,421	3,374	36	2,442	26	932-	10-
2002	16,953	6,999	41	1,099	6	5,900-	35-
2003	2,929	2,221	76	712	24	1,509-	52-
2004	2,052	4,195	204	55	3	4,140-	202-
2005	143	2,488			0	2,488-	
2006	7,368	6,267	85	78	1	6,189-	84-
2007	3,259	6,177	190	1,228	38	4,949-	152-
2008	694	6,862	989	332	48	6,529-	941-
2009	3,342	73,490		1,832	55	71,658-	
2010	2,392	10,021	419	1,912	80	8,109-	339-
2011	10,826	27,299	252	441	4	26,859-	248-
2012	1,132	14,187		96	8	14,091-	
2013	1,819	809	44	284	16	525-	29-
2014	3,265	38,898			0	38,898-	
2015	18,743	16,735	89	740	4	15,995-	85-
2016	2,669	13,132	492	91	3	13,041-	489-
2017	2,225	8,449	380	180	8	8,270-	372-
2018	8,286	5,752	69	559	7	5,193-	63-
2019	2,047	30,437		253	12	30,184-	
2020	9,138	29,795	326	2,702	30	27,093-	296-
2021	8,590	18,571	216	613	7	17,957-	209-
2022	9,074	30,270	334		0	30,270-	334-
2023	8,678	43,884	506	2-	0	43,886-	506-
2024	2,140	4,849	227	689	32	4,160-	194-
TOTAL	143,665	408,621	284	16,986	12	391,635-	273-

THREE-YEAR MOVING AVERAGES

00-02	10,951	4,611	42	1,397	13	3,214-	29-
01-03	9,768	4,198	43	1,418	15	2,780-	28-
02-04	7,311	4,472	61	622	9	3,850-	53-
03-05	1,708	2,968	174	256	15	2,712-	159-
04-06	3,188	4,317	135	44	1	4,272-	134-
05-07	3,590	4,977	139	435	12	4,542-	127-
06-08	3,774	6,435	171	546	14	5,889-	156-
07-09	2,432	28,843		1,131	47	27,712-	
08-10	2,142	30,124		1,359	63	28,766-	
09-11	5,520	36,937	669	1,395	25	35,542-	644-
10-12	4,783	17,169	359	816	17	16,353-	342-
11-13	4,592	14,098	307	274	6	13,825-	301-

KENTUCKY POWER COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	2,072	17,964	867	127	6	17,838-	861-
13-15	7,942	18,814	237	341	4	18,472-	233-
14-16	8,226	22,921	279	277	3	22,644-	275-
15-17	7,879	12,772	162	337	4	12,435-	158-
16-18	4,394	9,111	207	277	6	8,835-	201-
17-19	4,186	14,879	355	330	8	14,549-	348-
18-20	6,491	21,995	339	1,171	18	20,823-	321-
19-21	6,592	26,268	398	1,189	18	25,078-	380-
20-22	8,934	26,212	293	1,105	12	25,107-	281-
21-23	8,781	30,908	352	204	2	30,704-	350-
22-24	6,631	26,334	397	229	3	26,105-	394-
FIVE-YEAR AVERAGE							
20-24	7,524	25,474	339	800	11	24,673-	328-

KENTUCKY POWER COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	36,661	604	2	216	1	388-	1-
2001	11,194	394	4	6	0	388-	3-
2002	71,261	1,456	2	54	0	1,402-	2-
2003	23,089	953	4	814	4	139-	1-
2004	37,052	2,840	8	24	0	2,816-	8-
2005	36,728	9,431	26		0	9,431-	26-
2006	144,643	26,281	18	964	1	25,317-	18-
2007	36,512	9,708	27	1,580	4	8,128-	22-
2008	53,234	8,703	16	187	0	8,516-	16-
2009	77,397	11,925	15	1,580	2	10,346-	13-
2010	47,808	10,359	22	3,038	6	7,321-	15-
2011	110,598	9,735	9	3,074	3	6,661-	6-
2012	94,614	5,877	6	496-	1-	6,373-	7-
2013	65,079	28,935	44	10,165	16	18,770-	29-
2014	99,769	16,550	17	3,445	3	13,105-	13-
2015	73,658	25,891	35	660	1	25,230-	34-
2016	70,640	23,573	33	120	0	23,453-	33-
2017	55,038	16,713	30	298	1	16,415-	30-
2018	29,490	9,710	33	2,141	7	7,569-	26-
2019	18,627	3,020	16	63	0	2,957-	16-
2020	34,321	5,587	16	6,672	19	1,085	3
2021	49,660	19,553	39	18	0	19,535-	39-
2022	37,853	11,398	30	1,586	4	9,812-	26-
2023	33,456	12,956	39	5-	0	12,961-	39-
2024	25,296	9,456	37	61	0	9,396-	37-
TOTAL	1,373,680	281,607	21	36,263	3	245,344-	18-

THREE-YEAR MOVING AVERAGES

00-02	39,705	818	2	92	0	726-	2-
01-03	35,181	934	3	291	1	643-	2-
02-04	43,801	1,750	4	297	1	1,452-	3-
03-05	32,290	4,408	14	279	1	4,128-	13-
04-06	72,808	12,851	18	329	0	12,521-	17-
05-07	72,628	15,140	21	848	1	14,292-	20-
06-08	78,130	14,897	19	910	1	13,987-	18-
07-09	55,714	10,112	18	1,116	2	8,996-	16-
08-10	59,480	10,329	17	1,602	3	8,728-	15-
09-11	78,601	10,673	14	2,564	3	8,109-	10-
10-12	84,340	8,657	10	1,872	2	6,785-	8-
11-13	90,097	14,849	16	4,248	5	10,601-	12-

KENTUCKY POWER COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	86,488	17,121	20	4,371	5	12,749-	15-
13-15	79,502	23,792	30	4,757	6	19,035-	24-
14-16	81,356	22,005	27	1,409	2	20,596-	25-
15-17	66,445	22,059	33	359	1	21,699-	33-
16-18	51,723	16,665	32	853	2	15,812-	31-
17-19	34,385	9,814	29	834	2	8,980-	26-
18-20	27,480	6,105	22	2,958	11	3,147-	11-
19-21	34,203	9,387	27	2,251	7	7,136-	21-
20-22	40,612	12,179	30	2,759	7	9,421-	23-
21-23	40,323	14,636	36	533	1	14,103-	35-
22-24	32,202	11,270	35	547	2	10,723-	33-
FIVE-YEAR AVERAGE							
20-24	36,117	11,790	33	1,666	5	10,124-	28-



KENTUCKY POWER COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	1,443,110	191,989	13	413,109	29	221,120	15
2001	1,029,459	221,473	22	335,831	33	114,358	11
2002	1,055,795	659,515	62	678,285	64	18,770	2
2003	1,073,924	291,671	27	405,971	38	114,300	11
2004	1,076,234	238,854	22	124,013	12	114,841-	11-
2005	1,190,629	17,831	1	1,143	0	16,689-	1-
2006	1,756,227	348,675	20	423,177	24	74,502	4
2007	2,367,716	616,424	26	519,954	22	96,470-	4-
2008	2,310,335	538,110	23	575,481	25	37,371	2
2009	1,737,905	510,933	29	592,190	34	81,257	5
2010	1,455,999	391,862	27	557,150	38	165,288	11
2011	1,307,947	486,571	37	517,371	40	30,800	2
2012	1,841,401	1,184,273	64	530,596	29	653,677-	35-
2013	1,079,232	479,848	44	168,573	16	311,275-	29-
2014	1,340,831	684,093	51	407,569	30	276,524-	21-
2015	3,038,106	1,296,404	43	432,421	14	863,983-	28-
2016	1,653,096	453,938	27	152,761	9	301,177-	18-
2017	1,947,085	345,777	18	94,404	5	251,373-	13-
2018	2,273,868	477,123	21	125,312	6	351,811-	15-
2019	2,370,668	749,806	32	70,499	3	679,307-	29-
2020	1,924,357	703,823	37	91,105	5	612,718-	32-
2021	2,295,747	561,610	24	172,737	8	388,873-	17-
2022	2,080,275	917,831	44	116,321	6	801,510-	39-
2023	1,855,374	683,936	37	105,124	6	578,812-	31-
2024	1,959,698	710,353	36	194,340	10	516,013-	26-
TOTAL	43,465,018	13,762,724	32	7,805,438	18	5,957,285-	14-

THREE-YEAR MOVING AVERAGES

00-02	1,176,121	357,659	30	475,741	40	118,082	10
01-03	1,053,059	390,886	37	473,362	45	82,476	8
02-04	1,068,651	396,680	37	402,756	38	6,076	1
03-05	1,113,596	182,785	16	177,042	16	5,743-	1-
04-06	1,341,030	201,787	15	182,778	14	19,009-	1-
05-07	1,771,524	327,643	18	314,758	18	12,885-	1-
06-08	2,144,759	501,069	23	506,204	24	5,135	0
07-09	2,138,652	555,156	26	562,542	26	7,386	0
08-10	1,834,746	480,302	26	574,940	31	94,639	5
09-11	1,500,617	463,122	31	555,571	37	92,448	6
10-12	1,535,116	687,569	45	535,039	35	152,530-	10-
11-13	1,409,527	716,897	51	405,513	29	311,384-	22-

KENTUCKY POWER COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	1,420,488	782,738	55	368,913	26	413,825-	29-
13-15	1,819,390	820,115	45	336,188	18	483,927-	27-
14-16	2,010,678	811,479	40	330,917	16	480,561-	24-
15-17	2,212,762	698,707	32	226,529	10	472,178-	21-
16-18	1,958,016	425,613	22	124,159	6	301,454-	15-
17-19	2,197,207	524,235	24	96,738	4	427,497-	19-
18-20	2,189,631	643,584	29	95,639	4	547,945-	25-
19-21	2,196,924	671,746	31	111,447	5	560,299-	26-
20-22	2,100,126	727,755	35	126,721	6	601,033-	29-
21-23	2,077,132	721,126	35	131,394	6	589,732-	28-
22-24	1,965,116	770,707	39	138,595	7	632,112-	32-
FIVE-YEAR AVERAGE							
20-24	2,023,090	715,511	35	135,926	7	579,585-	29-

KENTUCKY POWER COMPANY

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	569,287	184,236	32	23,653	4	160,582-	28-
2001	390,080	321,367	82	31,367	8	290,000-	74-
2002	508,684	267,958	53	4,937	1	263,020-	52-
2003	630,850	131,104	21	3,269	1	127,835-	20-
2004	511,999	33,417	7	1,699	0	31,718-	6-
2005	760,371	293,637	39	122	0	293,515-	39-
2006	1,144,609	466,660	41	2,307	0	464,353-	41-
2007	887,176	326,376	37	992	0	325,384-	37-
2008	720,680	465,122	65	4,492	1	460,631-	64-
2009	467,957	514,287	110	5,661	1	508,626-	109-
2010	420,358	474,838	113	1,986	0	472,852-	112-
2011	370,511	440,260	119	458	0	439,802-	119-
2012	357,594	497,692	139	1,630	0	496,062-	139-
2013	335,346	149,102	44	52,380	16	96,721-	29-
2014	301,700	320,149	106	2,449	1	317,700-	105-
2015	287,441	339,427	118	1,903-	1-	341,330-	119-
2016	410,068	315,047	77	539	0	314,508-	77-
2017	412,692	372,992	90	2,869	1	370,123-	90-
2018	381,853	311,280	82	1,382	0	309,898-	81-
2019	452,167	437,956	97	1,166	0	436,790-	97-
2020	639,924	554,437	87	161	0	554,276-	87-
2021	398,124	420,024	106	3,941	1	416,084-	105-
2022	476,972	505,297	106	5,701-	1-	510,998-	107-
2023	497,636	474,196	95	2,570	1	471,626-	95-
2024	375,321	411,006	110	2,718	1	408,288-	109-
TOTAL	12,709,401	9,027,866	71	145,144	1	8,882,722-	70-

THREE-YEAR MOVING AVERAGES

00-02	489,350	257,854	53	19,986	4	237,868-	49-
01-03	509,871	240,143	47	13,191	3	226,952-	45-
02-04	550,511	144,160	26	3,302	1	140,858-	26-
03-05	634,407	152,719	24	1,697	0	151,023-	24-
04-06	805,660	264,571	33	1,376	0	263,196-	33-
05-07	930,719	362,224	39	1,140	0	361,084-	39-
06-08	917,488	419,386	46	2,597	0	416,789-	45-
07-09	691,938	435,262	63	3,715	1	431,547-	62-
08-10	536,332	484,749	90	4,046	1	480,703-	90-
09-11	419,609	476,461	114	2,702	1	473,760-	113-
10-12	382,821	470,930	123	1,358	0	469,572-	123-
11-13	354,484	362,351	102	18,156	5	344,195-	97-

KENTUCKY POWER COMPANY

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	331,547	322,314	97	18,820	6	303,494-	92-
13-15	308,162	269,559	87	17,642	6	251,917-	82-
14-16	333,070	324,874	98	362	0	324,513-	97-
15-17	370,067	342,489	93	502	0	341,987-	92-
16-18	401,538	333,106	83	1,597	0	331,510-	83-
17-19	415,571	374,076	90	1,806	0	372,270-	90-
18-20	491,315	434,558	88	903	0	433,655-	88-
19-21	496,739	470,806	95	1,756	0	469,050-	94-
20-22	505,007	493,253	98	533-	0	493,786-	98-
21-23	457,577	466,506	102	270	0	466,236-	102-
22-24	449,976	463,500	103	138-	0	463,637-	103-
FIVE-YEAR AVERAGE							
20-24	477,595	472,992	99	738	0	472,254-	99-

KENTUCKY POWER COMPANY

ACCOUNT 370.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	1,709,961	157,068	9	331,752	19	174,683	10
2001	639,511	461,377	72	351,294	55	110,083-	17-
2002	970,185	1,007,823	104	931,609	96	76,214-	8-
2003	624,632	329,105	53	210,012	34	119,092-	19-
2004	832,607	214,935	26	68,556	8	146,380-	18-
2005	1,515,899	93,784-	6-		0	93,784	6
2006	9,319,669	408,529	4	2,501,000	27	2,092,472	22
2007	9,974,912	768,675	8	702,707	7	65,968-	1-
2008	1,023,534	564,346	55	346,681	34	217,665-	21-
2009	915,027	543,026	59	548,069	60	5,043	1
2010	496,628	372,888	75	331,022	67	41,865-	8-
2011	465,676	363,976	78	288,244	62	75,732-	16-
2012	1,653,695	342,808	21	170,612	10	172,196-	10-
2013	866,022	385,051	44	135,270	16	249,781-	29-
2014	580,317	361,427	62	116,223	20	245,204-	42-
2015	589,062	431,511	73	154,819	26	276,692-	47-
2016	1,293,244	613,061	47		0	613,061-	47-
2017	1,088,948	64,155-	6-		0	64,155	6
2018	452,922	92,157	20	130	0	92,027-	20-
2019	457,404	142,015	31		0	142,015-	31-
2020	429,797	156,207	36		0	156,207-	36-
2021	313,063	138,995	44	505	0	138,490-	44-
2022	389,556	237,070	61		0	237,070-	61-
2023	393,210	187,082	48		0	187,082-	48-
2024	269,625	122,707	46		0	122,707-	46-
TOTAL	37,265,106	8,243,899	22	7,188,506	19	1,055,393-	3-

THREE-YEAR MOVING AVERAGES

00-02	1,106,552	542,090	49	538,218	49	3,871-	0
01-03	744,776	599,435	80	497,638	67	101,797-	14-
02-04	809,141	517,288	64	403,392	50	113,896-	14-
03-05	991,046	150,085	15	92,856	9	57,229-	6-
04-06	3,889,392	176,560	5	856,519	22	679,959	17
05-07	6,936,827	361,140	5	1,067,902	15	706,763	10
06-08	6,772,705	580,517	9	1,183,463	17	602,946	9
07-09	3,971,158	625,349	16	532,486	13	92,863-	2-
08-10	811,730	493,420	61	408,591	50	84,829-	10-
09-11	625,777	426,630	68	389,112	62	37,518-	6-
10-12	872,000	359,890	41	263,293	30	96,598-	11-
11-13	995,131	363,945	37	198,042	20	165,903-	17-

KENTUCKY POWER COMPANY

ACCOUNT 370.00 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	1,033,345	363,095	35	140,702	14	222,393-	22-
13-15	678,467	392,663	58	135,437	20	257,225-	38-
14-16	820,874	468,666	57	90,347	11	378,319-	46-
15-17	990,418	326,806	33	51,606	5	275,199-	28-
16-18	945,038	213,688	23	43	0	213,644-	23-
17-19	666,425	56,672	9	43	0	56,629-	8-
18-20	446,708	130,126	29	43	0	130,083-	29-
19-21	400,088	145,739	36	168	0	145,571-	36-
20-22	377,472	177,424	47	168	0	177,256-	47-
21-23	365,276	187,716	51	168	0	187,547-	51-
22-24	350,797	182,286	52		0	182,286-	52-
FIVE-YEAR AVERAGE							
20-24	359,050	168,412	47	101	0	168,311-	47-

KENTUCKY POWER COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	637,697	180,847	28	15,694	2	165,153-	26-
2001	563,686	351,757	62	15,480	3	336,277-	60-
2002	370,170	325,012	88	14,720	4	310,292-	84-
2003	155,458	323,387	208	13,108	8	310,279-	200-
2004	115,921	159,662	138	631	1	159,031-	137-
2005	818,524	134,474	16	9	0	134,465-	16-
2006	1,063,929	351,506	33	2,903	0	348,603-	33-
2007	930,355	315,987	34	3,250	0	312,738-	34-
2008	1,060,049	359,577	34	748-	0	360,326-	34-
2009	1,237,093	510,181	41	2,696	0	507,484-	41-
2010	1,185,896	445,487	38	1,197	0	444,290-	37-
2011	1,195,824	417,104	35	1,356	0	415,748-	35-
2012	1,189,432	429,221	36	1,288	0	427,933-	36-
2013	1,194,663	531,171	44	186,603	16	344,568-	29-
2014	1,155,610	329,852	29	2,884	0	326,968-	28-
2015	1,279,398	407,015	32	1,215-	0	408,229-	32-
2016	1,633,303	373,853	23	253	0	373,600-	23-
2017	1,525,458	329,569	22	639	0	328,929-	22-
2018	1,494,240	351,543	24	110	0	351,433-	24-
2019	1,813,361	467,448	26	357	0	467,091-	26-
2020	1,995,996	566,379	28	947	0	565,432-	28-
2021	2,082,603	543,422	26	448	0	542,974-	26-
2022	2,388,467	652,708	27	741-	0	653,449-	27-
2023	2,749,873	675,875	25	22-	0	675,897-	25-
2024	2,451,960	675,474	28	333	0	675,141-	28-
TOTAL	32,288,965	10,208,511	32	262,180	1	9,946,330-	31-

THREE-YEAR MOVING AVERAGES

00-02	523,851	285,872	55	15,298	3	270,574-	52-
01-03	363,105	333,385	92	14,436	4	318,949-	88-
02-04	213,850	269,353	126	9,486	4	259,867-	122-
03-05	363,301	205,841	57	4,582	1	201,258-	55-
04-06	666,125	215,214	32	1,181	0	214,033-	32-
05-07	937,603	267,322	29	2,054	0	265,269-	28-
06-08	1,018,111	342,357	34	1,801	0	340,555-	33-
07-09	1,075,832	395,248	37	1,733	0	393,516-	37-
08-10	1,161,013	438,415	38	1,048	0	437,367-	38-
09-11	1,206,271	457,591	38	1,750	0	455,841-	38-
10-12	1,190,384	430,604	36	1,281	0	429,323-	36-
11-13	1,193,306	459,165	38	63,083	5	396,083-	33-

KENTUCKY POWER COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	1,179,902	430,081	36	63,592	5	366,490-	31-
13-15	1,209,890	422,679	35	62,757	5	359,922-	30-
14-16	1,356,104	370,240	27	641	0	369,599-	27-
15-17	1,479,386	370,146	25	107-	0	370,253-	25-
16-18	1,551,000	351,655	23	334	0	351,321-	23-
17-19	1,611,019	382,853	24	369	0	382,485-	24-
18-20	1,767,866	461,790	26	471	0	461,319-	26-
19-21	1,963,987	525,750	27	584	0	525,166-	27-
20-22	2,155,689	587,503	27	218	0	587,285-	27-
21-23	2,406,981	624,002	26	105-	0	624,107-	26-
22-24	2,530,100	668,019	26	143-	0	668,162-	26-
FIVE-YEAR AVERAGE							
20-24	2,333,780	622,772	27	193	0	622,579-	27-



KENTUCKY POWER COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2000	26,217	5,880	22	801	3	5,079-	19-
2001	22,268	7,423	33	1,093	5	6,330-	28-
2002	27,698	7,791	28	1,010	4	6,782-	24-
2003	39,163	7,142	18	318	1	6,824-	17-
2004	33,892	4,631	14	182	1	4,449-	13-
2005	78,077	21,582	28		0	21,582-	28-
2006	145,114	21,265	15		0	21,265-	15-
2007	102,177	23,695	23	830	1	22,865-	22-
2008	97,394	23,544	24	1,132	1	22,412-	23-
2009	46,439	16,214	35	911	2	15,302-	33-
2010	57,335	19,833	35	107	0	19,725-	34-
2011	57,472	17,665	31	306	1	17,359-	30-
2012	62,663	19,259	31	367	1	18,892-	30-
2013	68,439	30,429	44	10,690	16	19,739-	29-
2014	63,003	22,327	35	35	0	22,292-	35-
2015	50,510	17,673	35	348	1	17,324-	34-
2016	80,264	29,342	37		0	29,342-	37-
2017	71,747	19,485	27		0	19,485-	27-
2018	79,088	29,951	38	179	0	29,772-	38-
2019	115,349	36,131	31	401	0	35,731-	31-
2020	104,987	45,962	44	389	0	45,573-	43-
2021	115,908	49,125	42	81	0	49,045-	42-
2022	136,728	57,516	42	278	0	57,238-	42-
2023	177,857	60,428	34		0	60,428-	34-
2024	314,620	71,200	23	5,370	2	65,830-	21-
TOTAL	2,174,410	665,493	31	24,827	1	640,667-	29-

THREE-YEAR MOVING AVERAGES

00-02	25,394	7,031	28	968	4	6,064-	24-
01-03	29,710	7,452	25	807	3	6,645-	22-
02-04	33,584	6,522	19	503	1	6,018-	18-
03-05	50,377	11,118	22	167	0	10,952-	22-
04-06	85,694	15,826	18	61	0	15,765-	18-
05-07	108,456	22,181	20	277	0	21,904-	20-
06-08	114,895	22,835	20	654	1	22,181-	19-
07-09	82,003	21,151	26	958	1	20,193-	25-
08-10	67,056	19,864	30	717	1	19,147-	29-
09-11	53,749	17,904	33	442	1	17,462-	32-
10-12	59,157	18,919	32	260	0	18,659-	32-
11-13	62,858	22,451	36	3,788	6	18,663-	30-

KENTUCKY POWER COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
12-14	64,702	24,005	37	3,697	6	20,308-	31-
13-15	60,651	23,476	39	3,691	6	19,785-	33-
14-16	64,592	23,114	36	128	0	22,986-	36-
15-17	67,507	22,167	33	116	0	22,050-	33-
16-18	77,033	26,259	34	60	0	26,200-	34-
17-19	88,728	28,522	32	193	0	28,329-	32-
18-20	99,808	37,348	37	323	0	37,025-	37-
19-21	112,082	43,739	39	290	0	43,449-	39-
20-22	119,208	50,868	43	249	0	50,619-	42-
21-23	143,498	55,690	39	119	0	55,570-	39-
22-24	209,735	63,048	30	1,882	1	61,166-	29-
FIVE-YEAR AVERAGE							
20-24	170,020	56,846	33	1,223	1	55,623-	33-

KENTUCKY POWER COMPANY  
ACCOUNT 389.10 LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2008	1		0		0		0
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
TOTAL	1		0		0		0
THREE-YEAR MOVING AVERAGES							
08-10			0		0		0
09-11							
10-12							
11-13							
12-14							
13-15							
14-16							
15-17							
16-18							
17-19							
18-20							
19-21							
20-22							
21-23							
22-24							
FIVE-YEAR AVERAGE							
20-24							

KENTUCKY POWER COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2001	182,029		0		0		0
2002	160,071		0		0		0
2003	1,426,227		0		0		0
2004	1,424,308		0		0		0
2005	149,701		0		0		0
2006	4,747	413	9		0	413-	9-
2007	7,134	3,250	46		0	3,250-	46-
2008	19,618	3,180	16		0	3,180-	16-
2009							
2010	25,349	6,360	25		0	6,360-	25-
2011	1,916	327	17		0	327-	17-
2012	675,528	132,550	20		0	132,550-	20-
2013	57,639	4,361	8		0	4,361-	8-
2014	254,632	21,148	8		0	21,148-	8-
2015	7,192	1,347	19		0	1,347-	19-
2016	37,481	45,134	120		0	45,134-	120-
2017	189,200	48,918	26		0	48,918-	26-
2018	149,243	19,073	13		0	19,073-	13-
2019	262,369	4,460	2		0	4,460-	2-
2020	6,331	925	15		0	925-	15-
2021	34,536	13,301	39		0	13,301-	39-
2022	118,398	102,461	87		0	102,461-	87-
2023	22,460	5,862	26		0	5,862-	26-
2024	718,733	49,414	7		0	49,414-	7-
TOTAL	5,934,841	462,483	8		0	462,483-	8-

THREE-YEAR MOVING AVERAGES

01-03	589,442		0		0		0
02-04	1,003,535		0		0		0
03-05	1,000,079		0		0		0
04-06	526,252	138	0		0	138-	0
05-07	53,861	1,221	2		0	1,221-	2-
06-08	10,500	2,281	22		0	2,281-	22-
07-09	8,917	2,143	24		0	2,143-	24-
08-10	14,989	3,180	21		0	3,180-	21-
09-11	9,088	2,229	25		0	2,229-	25-
10-12	234,264	46,412	20		0	46,412-	20-
11-13	245,028	45,746	19		0	45,746-	19-
12-14	329,266	52,686	16		0	52,686-	16-
13-15	106,488	8,952	8		0	8,952-	8-

KENTUCKY POWER COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
14-16	99,768	22,543	23		0	22,543-	23-
15-17	77,958	31,800	41		0	31,800-	41-
16-18	125,308	37,708	30		0	37,708-	30-
17-19	200,271	24,150	12		0	24,150-	12-
18-20	139,314	8,153	6		0	8,153-	6-
19-21	101,078	6,228	6		0	6,228-	6-
20-22	53,088	38,895	73		0	38,895-	73-
21-23	58,464	40,541	69		0	40,541-	69-
22-24	286,530	52,579	18		0	52,579-	18-
FIVE-YEAR AVERAGE							
20-24	180,091	34,392	19		0	34,392-	19-

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## **PART IX. DETAILED DEPRECIATION CALCULATIONS**

KENTUCKY POWER COMPANY

ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 70-R2						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
1963	2,891,208.28	2,531,321	2,025,387	1,183,854	13.38	88,479
1964	9,314.96	8,124	6,500	3,839	13.48	285
1965	12,956.51	11,255	9,005	5,376	13.58	396
1966	2,567.02	2,221	1,777	1,072	13.67	78
1967	153.20	132	106	64	13.76	5
1968	10,967.59	9,412	7,531	4,643	13.85	335
1970	131,388.16	111,805	89,459	56,382	14.01	4,024
1971	30,036.42	25,444	20,359	12,982	14.09	921
1972	10,482.03	8,838	7,072	4,564	14.17	322
1973	480.91	404	323	211	14.24	15
1974	923.96	772	618	408	14.31	29
1975	5,240.83	4,355	3,485	2,333	14.38	162
1976	12,121.72	10,021	8,018	5,437	14.45	376
1977	14,170.31	11,650	9,322	6,408	14.52	441
1978	52,188.22	42,672	34,143	23,786	14.58	1,631
1979	30,093.72	24,465	19,575	13,829	14.64	945
1980	191.25	155	124	88	14.70	6
1981	39,423.34	31,670	25,340	18,420	14.75	1,249
1982	118,150.94	94,299	75,452	55,696	14.81	3,761
1983	61,497.23	48,759	39,014	29,248	14.86	1,968
1984	484.40	381	305	233	14.91	16
1987	6,452.97	4,969	3,976	3,187	15.05	212
1988	31,694.20	24,207	19,369	15,812	15.09	1,048
1989	2,880.62	2,182	1,746	1,452	15.13	96
1990	32,209.28	24,176	19,344	16,408	15.17	1,082
1991	2,076.84	1,544	1,235	1,070	15.21	70
1992	3,824.33	2,816	2,253	1,992	15.25	131
1993	29,153.26	21,249	17,002	15,358	15.28	1,005
1994	218,837.25	157,733	126,207	116,702	15.32	7,618
1995	2,226.65	1,587	1,270	1,202	15.35	78
1996	69,386.04	48,855	39,090	37,928	15.38	2,466
1997	132,755.15	92,282	73,838	73,521	15.41	4,771
1998	247,224.11	169,517	135,636	138,783	15.44	8,989
1999	10,407.89	7,034	5,628	5,925	15.47	383
2000	31,263.12	20,803	16,645	18,057	15.50	1,165
2002	873,293.14	561,741	449,466	519,889	15.55	33,433
2003	35,799.64	22,592	18,077	21,661	15.58	1,390
2004	102,102.87	63,150	50,528	62,806	15.60	4,026
2005	339,407.49	205,426	164,368	212,375	15.62	13,596
2006	115,846.09	68,445	54,765	73,824	15.65	4,717

KENTUCKY POWER COMPANY

ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 70-R2						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
2007	169,932.80	97,846	78,290	110,336	15.67	7,041
2008	322,580.73	180,615	144,516	213,549	15.69	13,611
2009	198,618.66	107,868	86,308	134,158	15.71	8,540
2010	56,859.84	29,855	23,888	39,227	15.73	2,494
2011	58,886.37	29,778	23,826	41,538	15.75	2,637
2012	110,054.94	53,426	42,748	79,413	15.76	5,039
2013	68,919.90	31,939	25,555	50,946	15.78	3,229
2014	30,528.64	13,420	10,738	23,149	15.80	1,465
2015	2,061,661.08	854,436	683,660	1,604,784	15.81	101,504
2016	2,843,374.51	1,099,254	879,547	2,276,599	15.83	143,815
2017	1,538,392.08	549,220	439,448	1,268,168	15.84	80,061
2018	1,302,536.74	422,120	337,751	1,108,065	15.86	69,865
2019	359,758.66	104,018	83,228	316,104	15.87	19,918
2020	8,435,919.13	2,110,335	1,688,543	7,675,327	15.88	483,333
2021	845,040.10	175,124	140,122	797,872	15.90	50,181
2022	196,046.33	31,371	25,101	192,511	15.91	12,100
2023	95,207.94	10,250	8,201	97,479	15.92	6,123
2024	255,506.82	12,428	9,944	273,669	15.93	17,179
	24,670,707.21	10,391,766	8,314,769	19,069,716		1,219,855

MITCHELL  
INTERIM SURVIVOR CURVE.. IOWA 70-R2  
PROBABLE RETIREMENT YEAR.. 12-2040  
NET SALVAGE PERCENT.. -15

1971	8,042,358.88	7,096,907	5,998,831	3,249,882	13.79	235,669
1972	330,964.11	290,755	245,768	134,841	13.86	9,729
1973	63,556.00	55,578	46,979	26,111	13.93	1,874
1974	98,550.20	85,768	72,497	40,835	14.00	2,917
1975	45,274.50	39,214	33,147	18,919	14.06	1,346
1976	37,690.00	32,475	27,450	15,893	14.13	1,125
1977	17,013.54	14,584	12,327	7,238	14.19	510
1978	1,907,150.85	1,625,902	1,374,333	818,891	14.25	57,466
1979	175,521.00	148,829	125,801	76,048	14.30	5,318
1980	31,129.99	26,241	22,181	13,619	14.36	948
1981	21,643.00	18,135	15,329	9,560	14.41	663
1982	15,229.50	12,683	10,721	6,793	14.46	470
1983	3,573.80	2,957	2,499	1,610	14.51	111
1984	48,611.50	39,947	33,766	22,137	14.56	1,520



KENTUCKY POWER COMPANY

ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 70-R2						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
1985	73,254.50	59,768	50,520	33,722	14.61	2,308
1986	807,021.00	653,735	552,585	375,489	14.65	25,631
1987	19,938.00	16,029	13,549	9,380	14.69	639
1988	27,544.00	21,967	18,568	13,107	14.73	890
1989	335,870.50	265,640	224,539	161,712	14.77	10,949
1990	480,145.43	376,418	318,176	233,991	14.81	15,800
1991	75,575.00	58,701	49,618	37,293	14.85	2,511
1992	209,793.26	161,414	136,439	104,823	14.88	7,045
1993	76,995.74	58,629	49,558	38,988	14.92	2,613
1994	14,809.50	11,157	9,431	7,600	14.95	508
1995	279,560.96	208,284	176,057	145,438	14.98	9,709
1996	1,590.50	1,171	990	839	15.01	56
1997	273,535.00	198,834	168,069	146,496	15.04	9,740
1998	38,919.80	27,912	23,593	21,164	15.07	1,404
1999	229,936.77	162,570	137,416	127,011	15.10	8,411
2000	771,080.92	537,038	453,944	432,799	15.12	28,624
2001	171,933.13	117,799	99,572	98,151	15.15	6,479
2002	198,813.41	133,923	113,202	115,434	15.17	7,609
2003	129,661.11	85,737	72,471	76,639	15.19	5,045
2004	562,049.63	364,158	307,813	338,544	15.22	22,243
2005	120,548.14	76,455	64,625	74,005	15.24	4,856
2006	167,176.95	103,592	87,564	104,690	15.26	6,860
2007	13,720,690.56	8,288,916	7,006,405	8,772,389	15.28	574,109
2008	1,388,484.47	815,991	689,736	907,021	15.30	59,282
2009	4,866,145.90	2,774,083	2,344,860	3,251,208	15.32	212,220
2010	1,462,576.73	807,023	682,156	999,808	15.33	65,219
2011	1,487,783.39	791,058	668,661	1,042,290	15.35	67,902
2012	380,395.98	194,108	164,074	273,381	15.37	17,787
2013	634,111.86	308,901	261,106	468,123	15.39	30,417
2014	9,841,996.33	4,554,595	3,849,881	7,468,415	15.40	484,962
2015	338,469.03	147,611	124,772	264,468	15.42	17,151
2016	661,558.45	269,617	227,900	532,892	15.43	34,536
2017	812,524.35	306,045	258,692	675,711	15.44	43,764
2018	3,238,284.77	1,108,233	936,761	2,787,267	15.46	180,289
2019	358,778.50	109,515	92,570	320,025	15.47	20,687
2020	176,301.10	46,678	39,456	163,291	15.48	10,549
2021	118,968.96	26,148	22,102	114,712	15.49	7,406
2022	273,506.88	46,340	39,170	275,363	15.51	17,754

KENTUCKY POWER COMPANY

ACCOUNT 311.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 70-R2						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
2023	560,014.57	63,919	54,029	589,988	15.52	38,015
2024	24,992,520.08	1,290,489	1,090,817	27,650,581	15.53	1,780,462
2025	75,741.87	723	611	86,492	15.53	5,569
	81,292,873.90	35,140,899	29,703,688	63,783,117		4,167,676
	105,963,581.11	45,532,665	38,018,457	82,852,833		5,387,531
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						15.4 5.08

KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 60-R0.5						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
1963	1,600,233.07	1,338,020	1,424,301	351,958	13.37	26,324
1964	74,130.35	61,751	65,733	16,552	13.44	1,232
1965	22,980.33	19,074	20,304	5,204	13.50	385
1966	25,740.45	21,285	22,658	5,914	13.56	436
1967	972.02	801	853	226	13.62	17
1968	27,946.20	22,928	24,406	6,614	13.68	483
1970	207,880.34	169,152	180,060	50,688	13.79	3,676
1971	147,607.58	119,575	127,286	36,559	13.85	2,640
1972	61,782.67	49,829	53,042	15,537	13.90	1,118
1973	5,202.47	4,177	4,446	1,328	13.95	95
1974	52,885.48	42,260	44,985	13,718	14.00	980
1975	88,189.48	70,122	74,644	23,247	14.05	1,655
1976	36,117.62	28,573	30,416	9,675	14.10	686
1977	54,154.23	42,613	45,361	14,750	14.15	1,042
1978	235,311.41	184,187	196,064	65,132	14.19	4,590
1979	269,392.70	209,644	223,163	75,863	14.24	5,327
1980	142,609.93	110,344	117,459	40,838	14.28	2,860
1981	194,101.70	149,287	158,914	56,539	14.32	3,948
1982	350,177.97	267,645	284,904	103,794	14.36	7,228
1983	159,814.51	121,350	129,175	48,219	14.40	3,349
1984	120,854.66	91,141	97,018	37,131	14.44	2,571
1985	146,983.35	110,051	117,148	46,004	14.48	3,177
1986	121,432.04	90,259	96,079	38,710	14.51	2,668
1987	266,496.92	196,525	209,198	86,614	14.55	5,953
1988	191,531.11	140,126	149,162	63,438	14.58	4,351
1989	122,519.84	88,859	94,589	41,408	14.62	2,832
1990	143,166.93	102,925	109,562	49,353	14.65	3,369
1991	107,650.02	76,677	81,621	37,870	14.68	2,580
1992	238,991.61	168,570	179,440	85,841	14.71	5,836
1993	173,159.60	120,879	128,674	63,533	14.74	4,310
1994	412,803.02	285,035	303,415	154,796	14.77	10,480
1995	873,616.32	596,355	634,810	334,904	14.80	22,629
1996	707,086.25	476,986	507,744	277,122	14.82	18,699
1997	462,747.73	308,108	327,976	185,674	14.85	12,503
1998	314,138.36	206,402	219,712	128,982	14.87	8,674
1999	13,921.94	9,013	9,594	5,859	14.90	393
2000	51,191.50	32,641	34,746	22,077	14.92	1,480
2001	28,569.48	17,923	19,079	12,633	14.94	846
2002	208,888.16	128,783	137,087	94,778	14.96	6,335
2004	518,322.50	307,323	327,140	248,198	15.00	16,547

KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 60-R0.5						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
2005	402,760.52	233,622	248,687	198,377	15.02	13,208
2006	551,059.95	312,212	332,345	279,332	15.04	18,573
2007	313,893.28	173,340	184,518	163,904	15.06	10,883
2008	901,762.71	484,023	515,235	485,722	15.08	32,210
2009	80,594.35	41,993	44,701	44,759	15.09	2,966
2010	637,775.00	321,202	341,914	366,016	15.11	24,223
2011	429,130.03	208,296	221,728	254,607	15.12	16,839
2012	806,943.69	375,731	399,960	495,748	15.14	32,744
2013	190,556.87	84,757	90,222	121,296	15.15	8,006
2014	74,053.68	31,241	33,256	48,944	15.17	3,226
2015	107,380.17	42,720	45,475	73,717	15.18	4,856
2016	59,967,356.35	22,246,276	23,680,806	42,882,960	15.20	2,821,247
2017	1,793,692.86	614,502	654,128	1,336,871	15.21	87,894
2018	961,419.09	299,577	318,895	748,280	15.22	49,164
2019	135,952.20	37,727	40,160	110,747	15.24	7,267
2020	75,258.12	18,072	19,237	64,299	15.25	4,216
2021	334,481.74	66,670	70,969	300,306	15.26	19,679
2022	160,658.95	24,743	26,339	151,993	15.27	9,954
2023	122,966.29	12,710	13,530	122,963	15.29	8,042
2024	9,958,641.10	463,719	493,621	10,560,470	15.30	690,227
	86,987,638.80	32,680,331	34,787,691	61,768,588		4,069,728

MITCHELL  
INTERIM SURVIVOR CURVE.. IOWA 60-R0.5  
PROBABLE RETIREMENT YEAR.. 12-2040  
NET SALVAGE PERCENT.. -15

1971	30,597,949.65	25,855,176	23,611,297	11,576,345	13.55	854,343
1972	3,587,690.51	3,018,468	2,756,506	1,369,338	13.60	100,687
1973	380,929.07	319,045	291,356	146,712	13.65	10,748
1974	248,037.32	206,773	188,828	96,415	13.70	7,038
1975	414,444.93	343,885	314,040	162,571	13.74	11,832
1976	5,135,016.77	4,239,275	3,871,363	2,033,906	13.79	147,491
1977	6,331,101.32	5,200,797	4,749,438	2,531,328	13.83	183,032
1978	33,283,927.73	27,192,020	24,832,121	13,444,396	13.88	968,616
1979	1,025,432.16	833,150	760,844	418,403	13.92	30,058
1980	1,021,231.43	825,074	753,469	420,947	13.96	30,154
1981	1,060,817.00	851,933	777,997	441,943	14.00	31,567
1982	1,186,665.48	947,146	864,947	499,719	14.04	35,593

KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 60-R0.5						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
1983	695,530.22	551,527	503,662	296,198	14.08	21,037
1984	1,267,892.10	998,942	912,247	545,829	14.11	38,684
1985	146,100.00	114,289	104,370	63,645	14.15	4,498
1987	2,466,681.09	1,901,003	1,736,022	1,100,662	14.22	77,402
1988	2,411,180.43	1,843,784	1,683,769	1,089,089	14.25	76,427
1989	685,209.24	519,625	474,529	313,462	14.28	21,951
1990	465.17	350	320	215	14.31	15
1991	766,937.03	571,301	521,720	360,258	14.34	25,123
1992	786,944.17	580,603	530,215	374,771	14.37	26,080
1993	3,137,453.75	2,291,378	2,092,517	1,515,554	14.40	105,247
1994	11,665,720.28	8,427,532	7,696,136	5,719,442	14.43	396,358
1995	237,160.30	169,458	154,751	117,983	14.45	8,165
1996	304,320.04	214,835	196,190	153,778	14.48	10,620
1997	1,802,029.39	1,256,456	1,147,413	924,921	14.50	63,788
1998	191,134.43	131,518	120,104	99,701	14.52	6,866
2000	1,792,282.10	1,197,431	1,093,510	967,614	14.57	66,411
2001	6,219,362.03	4,088,522	3,733,694	3,418,573	14.59	234,309
2002	3,834,051.10	2,477,594	2,262,572	2,146,586	14.61	146,926
2003	1,043,965.77	662,109	604,647	595,914	14.63	40,732
2004	2,076,698.13	1,291,086	1,179,037	1,209,166	14.65	82,537
2005	12,930,424.44	7,866,967	7,184,221	7,685,767	14.67	523,910
2006	14,110,432.78	8,393,577	7,665,128	8,561,869	14.68	583,234
2007	492,707,521.14	285,697,934	260,903,224	305,710,426	14.70	20,796,628
2008	22,157,542.13	12,493,419	11,409,159	14,072,014	14.72	955,979
2009	14,754,272.71	8,076,319	7,375,404	9,592,010	14.73	651,189
2010	2,944,896.11	1,558,866	1,423,578	1,963,053	14.75	133,088
2011	3,837,079.53	1,958,595	1,788,615	2,624,026	14.76	177,780
2012	8,758,307.46	4,290,896	3,918,504	6,153,549	14.78	416,343
2013	16,798,180.63	7,862,002	7,179,687	12,138,221	14.79	820,705
2014	89,137,612.16	39,635,841	36,195,987	66,312,267	14.80	4,480,559
2015	20,465,239.92	8,571,927	7,828,000	15,707,026	14.82	1,059,853
2016	4,282,381.06	1,677,366	1,531,793	3,392,945	14.83	228,789
2017	4,318,240.69	1,562,048	1,426,483	3,539,493	14.84	238,510
2018	8,998,216.86	2,963,653	2,706,448	7,641,501	14.85	514,579
2019	24,164,206.76	7,086,432	6,471,426	21,317,412	14.87	1,433,585
2020	3,293,800.22	836,892	764,261	3,023,609	14.88	203,200
2021	4,028,171.85	850,786	776,949	3,855,448	14.89	258,929
2022	17,556,173.94	2,870,961	2,621,800	17,567,800	14.90	1,179,047

KENTUCKY POWER COMPANY

ACCOUNT 312.00 BOILER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 60-R0.5						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
2023	18,539,338.16	2,029,900	1,853,732	19,466,507	14.92	1,304,726
2024	5,673,787.99	280,243	255,922	6,268,934	14.93	419,888
2025	1,108,022.29	10,156	9,275	1,264,951	14.93	84,725
	916,368,208.97	505,696,865	461,809,228	592,014,212		40,329,581
	1,003,355,847.77	538,377,196	496,596,919	653,782,800		44,399,309
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						14.7 4.43

KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
1963	5,344,980.20	4,565,922	4,581,296	1,351,632	12.85	105,185
1965	6.22	5	5	2	13.03	
1966	59,187.82	49,975	50,143	15,555	13.12	1,186
1970	308,934.56	256,482	257,346	85,572	13.45	6,362
1971	300,481.97	248,340	249,176	84,359	13.53	6,235
1972	112,908.70	92,876	93,189	32,140	13.61	2,361
1973	25,292.94	20,709	20,779	7,296	13.68	533
1974	6,216.15	5,065	5,082	1,818	13.75	132
1975	240,134.00	194,671	195,327	71,222	13.82	5,154
1976	3,981.47	3,211	3,222	1,198	13.89	86
1977	8,170.37	6,553	6,575	2,494	13.96	179
1978	4,806.90	3,834	3,847	1,489	14.02	106
1979	222,433.97	176,443	177,037	69,865	14.08	4,962
1981	809,682.73	634,516	636,653	262,095	14.20	18,457
1982	176,639.95	137,528	137,991	58,079	14.26	4,073
1983	433,828.36	335,515	336,645	144,905	14.32	10,119
1984	25,265.93	19,408	19,473	8,572	14.37	597
1985	485.17	370	371	167	14.42	12
1986	30,319.28	22,944	23,021	10,633	14.48	734
1987	96,781.50	72,686	72,931	34,497	14.52	2,376
1988	1,389,326.75	1,034,954	1,038,439	503,714	14.57	34,572
1989	834,871.31	616,529	618,605	308,102	14.62	21,074
1990	406,098.08	297,269	298,270	152,499	14.66	10,402
1991	690,000.03	500,248	501,932	263,968	14.71	17,945
1993	1,125,177.32	799,401	802,093	446,854	14.79	30,213
1994	926,657.58	651,200	653,393	375,197	14.83	25,300
1995	486,981.00	338,286	339,425	201,124	14.87	13,525
1996	598,554.72	410,889	412,273	252,123	14.90	16,921
1998	4,339,966.98	2,900,920	2,910,688	1,906,675	14.97	127,366
1999	3,094.61	2,039	2,046	1,389	15.00	93
2000	21,296.44	13,819	13,866	9,774	15.03	650
2001	4,859.57	3,102	3,112	2,282	15.06	152
2002	2,849,666.84	1,787,169	1,793,187	1,369,943	15.09	90,785
2003	360,882.46	222,073	222,821	177,759	15.12	11,757
2004	641,489.23	386,730	388,032	324,021	15.15	21,388
2005	237,863.16	140,331	140,804	123,225	15.17	8,123
2006	530,585.07	305,841	306,871	282,079	15.19	18,570
2007	309,686.86	173,939	174,525	169,228	15.22	11,119
2008	30,123,750.76	16,456,867	16,512,281	16,925,082	15.24	1,110,570
2009	25,382.29	13,450	13,495	14,679	15.26	962

KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
2010	17,442.31	8,937	8,967	10,394	15.28	680
2011	154,350.70	76,216	76,473	94,857	15.30	6,200
2012	67,390.20	31,930	32,038	42,766	15.32	2,792
2013	1,992,030.36	901,023	904,057	1,307,097	15.34	85,208
2014	275,977.02	118,423	118,822	187,513	15.36	12,208
2015	109,145.74	44,173	44,322	76,830	15.37	4,999
2016	182,921.56	69,102	69,335	133,708	15.39	8,688
2017	692,626.24	241,562	242,375	526,440	15.41	34,162
2018	3,754,600.95	1,189,102	1,193,106	2,974,501	15.43	192,774
2019	61,445.12	17,356	17,414	50,790	15.44	3,290
2020	1,047,480.00	256,225	257,088	905,615	15.46	58,578
2022	30,952.35	4,856	4,872	29,485	15.49	1,903
2023	1,493,378.71	156,764	157,292	1,500,359	15.51	96,735
2024	464,427.69	21,930	22,004	493,511	15.53	31,778
	64,460,898.20	37,039,708	37,164,429	34,387,168		2,280,331

MITCHELL  
INTERIM SURVIVOR CURVE.. IOWA 60-R1  
PROBABLE RETIREMENT YEAR.. 12-2040  
NET SALVAGE PERCENT.. -15

1970	102,162.97	88,381	81,292	36,196	13.18	2,746
1971	20,416,443.86	17,586,878	16,176,166	7,302,745	13.25	551,151
1972	196,653.77	168,641	155,114	71,038	13.32	5,333
1973	30,557.00	26,085	23,993	11,148	13.39	833
1974	371,702.50	315,780	290,450	137,008	13.46	10,179
1975	17,605.86	14,882	13,688	6,558	13.53	485
1976	78,845.00	66,319	60,999	29,672	13.59	2,183
1977	56,966.20	47,656	43,833	21,678	13.66	1,587
1978	50,018.47	41,619	38,281	19,241	13.72	1,402
1979	65,111.00	53,871	49,550	25,328	13.78	1,838
1980	32,273.52	26,555	24,425	12,690	13.83	918
1981	212,125.50	173,471	159,556	84,388	13.89	6,075
1982	17,981.08	14,610	13,438	7,240	13.95	519
1983	14,571.50	11,764	10,820	5,937	14.00	424
1984	988,936.23	793,057	729,443	407,834	14.05	29,027
1985	51,673.00	41,146	37,846	21,578	14.10	1,530
1986	172,897.50	136,655	125,693	73,139	14.15	5,169
1987	467,235.00	366,436	337,043	200,278	14.20	14,104



KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
1988	1,499,542.00	1,166,882	1,073,282	651,191	14.24	45,730
1989	1,164,043.00	898,087	826,048	512,602	14.29	35,871
1990	110,097.50	84,201	77,447	49,165	14.33	3,431
1991	103,542.28	78,468	72,174	46,900	14.37	3,264
1992	2,839,665.90	2,131,141	1,960,194	1,305,422	14.41	90,591
1993	4,415,387.70	3,279,785	3,016,701	2,060,995	14.45	142,629
1994	350,644.22	257,776	237,099	166,142	14.48	11,474
1995	9,037.27	6,568	6,041	4,352	14.52	300
1996	9,866.64	7,086	6,518	4,829	14.55	332
1997	1,215,768.11	862,033	792,886	605,247	14.59	41,484
1998	260,795.06	182,456	167,820	132,094	14.62	9,035
1999	690,324.86	476,110	437,919	355,954	14.65	24,297
2000	561,647.85	381,556	350,950	294,945	14.68	20,092
2001	424,224.47	283,519	260,777	227,081	14.71	15,437
2002	417,643.77	274,452	252,437	227,853	14.73	15,469
2003	103,614.09	66,828	61,467	57,689	14.76	3,908
2004	308,195.89	194,913	179,278	175,147	14.78	11,850
2005	4,250,181.31	2,629,832	2,418,883	2,468,826	14.81	166,700
2006	400,037.90	241,863	222,462	237,581	14.83	16,020
2007	355,020.12	209,297	192,508	215,765	14.85	14,530
2008	23,230.11	13,326	12,257	14,458	14.87	972
2009	233,317.87	129,881	119,463	148,853	14.89	9,997
2010	118,036.83	63,563	58,464	77,278	14.91	5,183
2011	1,255,484.70	651,590	599,323	844,484	14.93	56,563
2012	1,560,988.21	777,797	715,407	1,079,730	14.95	72,223
2013	775,066.00	368,884	339,294	552,032	14.97	36,876
2014	40,700.34	18,408	16,931	29,874	14.98	1,994
2015	1,984,984.48	845,844	777,996	1,504,737	15.00	100,316
2016	201,632.58	80,253	73,816	158,062	15.02	10,523
2017	523,633.43	192,643	177,190	424,988	15.03	28,276
2018	929,301.80	311,098	286,144	782,553	15.05	51,997
2019	1,388,695.08	414,357	381,120	1,215,880	15.07	80,682
2020	32,077.48	8,303	7,637	29,252	15.08	1,940
2022	5,649,733.03	938,130	862,879	5,634,314	15.11	372,886

KENTUCKY POWER COMPANY

ACCOUNT 314.00 TURBOGENERATOR UNITS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 60-R1						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
2023	161,709.12	18,087	16,636	169,329	15.13	11,192
2024	4,106,213.79	208,672	191,934	4,530,212	15.14	299,221
2025	613.30	6	6	700	15.15	46
	61,818,458.05	38,727,501	35,621,017	35,470,210		2,448,834
	126,279,356.25	75,767,209	72,785,446	69,857,378		4,729,165
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						14.8 3.75

KENTUCKY POWER COMPANY

ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 55-R1.5						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
1963	1,338,845.98	1,177,839	877,382	608,737	11.09	54,891
1965	1,390.04	1,212	903	640	11.39	56
1970	134,342.59	114,323	85,160	63,960	12.12	5,277
1971	86,296.61	73,060	54,423	41,366	12.26	3,374
1972	3,233.97	2,723	2,028	1,561	12.40	126
1973	27,714.09	23,213	17,292	13,471	12.53	1,075
1974	361.57	301	224	177	12.66	14
1976	70,411.59	57,988	43,196	34,961	12.91	2,708
1977	27,666.26	22,652	16,874	13,836	13.03	1,062
1978	52,679.39	42,864	31,930	26,544	13.15	2,019
1979	9,493.76	7,678	5,719	4,819	13.26	363
1980	15,962.42	12,822	9,551	8,167	13.38	610
1981	104,237.05	83,196	61,973	53,730	13.48	3,986
1982	85,905.65	68,086	50,718	44,637	13.59	3,285
1983	21,612.09	17,008	12,669	11,320	13.69	827
1984	21,442.36	16,754	12,480	11,321	13.78	822
1985	21,176.38	16,418	12,230	11,276	13.88	812
1987	28,149.17	21,474	15,996	15,249	14.06	1,085
1989	24,337.10	18,248	13,593	13,421	14.22	944
1990	51,643.26	38,362	28,576	28,748	14.30	2,010
1991	25,781.68	18,971	14,132	14,486	14.37	1,008
1992	9,431.89	6,871	5,118	5,351	14.44	371
1993	28,078.58	20,236	15,074	16,093	14.51	1,109
1994	4,126.35	2,941	2,191	2,389	14.58	164
1995	2,768.63	1,950	1,453	1,621	14.64	111
1996	79,163.96	55,079	41,029	46,843	14.70	3,187
1997	225,262.90	154,676	115,219	134,822	14.76	9,134
1998	76,836.63	52,026	38,755	46,534	14.82	3,140
1999	694.73	464	346	426	14.87	29
2000	25,028.61	16,444	12,249	15,532	14.92	1,041
2001	17,168.01	11,094	8,264	10,792	14.97	721
2002	55,858.22	35,473	26,424	35,578	15.01	2,370
2003	216,931.04	135,131	100,660	140,133	15.06	9,305
2004	4,789.07	2,923	2,177	3,139	15.10	208
2005	1,658.28	990	737	1,103	15.14	73
2006	44,223.83	25,788	19,210	29,879	15.18	1,968
2007	42,150.50	23,949	17,840	28,947	15.22	1,902
2008	58,685.81	32,431	24,158	40,983	15.25	2,687
2009	72,038.28	38,615	28,765	51,198	15.28	3,351
2010	40,317.72	20,896	15,566	29,187	15.31	1,906

KENTUCKY POWER COMPANY

ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 55-R1.5						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
2011	6,264.24	3,126	2,329	4,625	15.35	301
2012	115,472.63	55,345	41,227	86,948	15.37	5,657
2013	24,183.06	11,059	8,238	18,605	15.40	1,208
2015	74,318.39	30,408	22,651	59,842	15.45	3,873
2016	185,386.73	70,745	52,699	153,081	15.48	9,889
2017	64,598.93	22,765	16,958	54,747	15.50	3,532
2018	1,182,018.80	378,222	281,741	1,030,300	15.53	66,343
2019	253,718.85	72,392	53,925	227,703	15.55	14,643
2020	333,795.65	82,502	61,456	309,057	15.57	19,850
2021	13,466.03	2,760	2,056	12,891	15.59	827
2022	901,269.42	142,838	106,401	894,008	15.61	57,271
2024	2,121,215.09	102,187	76,120	2,278,429	15.65	145,587
	8,433,603.87	3,447,518	2,568,085	6,793,216		458,112

MITCHELL

INTERIM SURVIVOR CURVE.. IOWA 55-R1.5

PROBABLE RETIREMENT YEAR.. 12-2040

NET SALVAGE PERCENT.. -15

1971	6,053,099.71	5,335,238	4,654,532	2,306,532	12.04	191,572
1972	351,890.37	308,580	269,209	135,465	12.17	11,131
1974	3,968.88	3,443	3,004	1,560	12.43	126
1976	2,531.00	2,171	1,894	1,017	12.67	80
1977	30,659.58	26,154	22,817	12,441	12.78	973
1978	4,229,201.11	3,586,502	3,128,912	1,734,669	12.89	134,575
1979	13,794.11	11,627	10,144	5,720	13.00	440
1980	21,277.52	17,819	15,546	8,924	13.11	681
1981	1,151.00	958	836	488	13.21	37
1982	10,350.00	8,555	7,463	4,439	13.31	334
1983	735,804.50	604,051	526,982	319,193	13.40	23,820
1984	180,233.50	146,873	128,134	79,135	13.50	5,862
1985	67,719.50	54,774	47,786	30,092	13.59	2,214
1987	191,826.90	152,788	133,294	87,307	13.75	6,350
1988	3,680.97	2,907	2,536	1,697	13.83	123
1989	233,810.50	183,060	159,704	109,178	13.91	7,849
1990	31,159.73	24,178	21,093	14,740	13.98	1,054
1991	197,304.91	151,660	132,310	94,590	14.05	6,732
1992	47,212.00	35,932	31,348	22,946	14.12	1,625
1993	50,495.40	38,026	33,174	24,895	14.19	1,754

## KENTUCKY POWER COMPANY

ACCOUNT 315.00 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR	ORIGINAL COST	CALCULATED ACCRUED	ALLOC. BOOK RESERVE	FUTURE BOOK ACCRUALS	REM. LIFE	ANNUAL ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 55-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
1994	71,172.01	53,014	46,250	35,598	14.25	2,498
1995	6,772.50	4,987	4,351	3,438	14.31	240
1996	9,707.50	7,061	6,160	5,004	14.37	348
1997	9,116.00	6,548	5,713	4,771	14.42	331
1998	36,602.34	25,937	22,628	19,465	14.47	1,345
2000	10,039.74	6,906	6,025	5,521	14.57	379
2002	27,630.66	18,374	16,030	15,746	14.66	1,074
2003	166,939.92	108,978	95,074	96,907	14.70	6,592
2004	65,265.34	41,752	36,425	38,630	14.74	2,621
2005	478,320.31	299,452	261,246	288,822	14.78	19,541
2006	172,611.99	105,554	92,087	106,417	14.82	7,181
2007	122,363.69	72,960	63,651	77,067	14.85	5,190
2008	41,835.96	24,272	21,175	26,936	14.88	1,810
2009	122,090.42	68,688	59,924	80,480	14.92	5,394
2010	193,084.30	105,077	91,671	130,376	14.95	8,721
2011	478,027.45	250,914	218,901	330,831	14.97	22,100
2012	137,070.30	69,041	60,232	97,399	15.00	6,493
2013	1,995,309.20	959,925	837,451	1,457,154	15.03	96,950
2014	462,467.92	211,289	184,331	347,507	15.05	23,090
2015	7,065,666.40	3,041,137	2,653,128	5,472,388	15.08	362,890
2016	445,899.20	179,464	156,567	356,217	15.10	23,591
2017	263,283.33	97,854	85,369	217,407	15.12	14,379
2018	555,415.65	187,601	163,666	475,062	15.15	31,357
2019	272,139.34	81,933	71,479	241,481	15.17	15,918
2020	69,749.74	18,206	15,883	64,329	15.19	4,235
2021	204,252.92	44,246	38,601	196,290	15.21	12,905
2022	388,884.26	64,999	56,706	390,511	15.23	25,641
2023	380,474.68	42,976	37,493	400,053	15.24	26,250
2024	78,748.61	4,026	3,512	87,049	15.26	5,704
2025	243,646.73	2,186	1,907	278,287	15.27	18,224
	27,031,759.60	16,900,653	14,744,354	16,342,169		1,150,324
	35,465,363.47	20,348,171	17,312,439	23,135,385		1,608,436
	COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..				14.4	4.54

KENTUCKY POWER COMPANY

ACCOUNT 315.10 COMPUTER HARDWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	2,307.57	2,308	2,308			
2024	13,282.50	1,992	1,661-	14,943	4.25	3,516
	15,590.07	4,300	647	14,943		3,516
MITCHELL						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	11,581.53	11,002	1,655	9,927	0.25	9,927
2021	14,146.44	10,610	1,596	12,550	1.25	10,040
	25,727.97	21,612	3,251	22,477		19,967
	41,318.04	25,912	3,898	37,420		23,483
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						1.6 56.83

KENTUCKY POWER COMPANY

ACCOUNT 315.31 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	38,756.87	20,025	10,495	28,262	7.25	3,898
2024	15,287.30	764	400	14,887	14.25	1,045
	54,044.17	20,789	10,895	43,149		4,943
MITCHELL						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	42,404.60	42,405	42,405			
2010	6,245.15	6,141	520-	6,765	0.25	6,765
2011	29,158.58	26,729	2,265-	31,423	1.25	25,138
2024	5,606.88	280	24-	5,631	14.25	395
	83,415.21	75,555	39,596	43,819		32,298
	137,459.38	96,344	50,491	86,968		37,241
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.3						27.09

KENTUCKY POWER COMPANY

ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
1963	621,964.07	564,310	482,702	207,678	10.69	19,427
1964	4,003.13	3,614	3,091	1,352	10.89	124
1965	4,603.08	4,135	3,537	1,572	11.09	142
1966	7,226.15	6,458	5,524	2,497	11.29	221
1967	2,020.53	1,796	1,536	707	11.49	62
1968	3,236.81	2,862	2,448	1,145	11.69	98
1970	55,921.00	48,885	41,816	20,257	12.08	1,677
1971	24,019.33	20,880	17,860	8,801	12.26	718
1972	13,632.46	11,780	10,076	5,056	12.45	406
1973	6,537.60	5,617	4,805	2,452	12.62	194
1975	35,356.67	30,007	25,668	13,578	12.96	1,048
1976	5,269.89	4,444	3,801	2,048	13.12	156
1977	2,542.76	2,131	1,823	1,000	13.27	75
1978	9,747.50	8,116	6,942	3,877	13.42	289
1979	6,756.25	5,588	4,780	2,720	13.56	201
1980	3,169.32	2,603	2,227	1,291	13.70	94
1981	26,500.32	21,616	18,490	10,925	13.83	790
1982	20,492.90	16,597	14,197	8,550	13.95	613
1984	18,468.01	14,735	12,604	7,895	14.18	557
1985	24,183.46	19,149	16,380	10,464	14.28	733
1986	27,264.63	21,415	18,318	11,946	14.38	831
1987	9,064.52	7,060	6,039	4,023	14.48	278
1988	8,303.38	6,411	5,484	3,733	14.57	256
1989	23,371.46	17,887	15,300	10,642	14.65	726
1990	4,823.54	3,657	3,128	2,226	14.73	151
1991	8,298.29	6,231	5,330	3,881	14.81	262
1992	22,469.72	16,702	14,287	10,655	14.88	716
1993	3,212.30	2,362	2,020	1,545	14.95	103
1994	351,390.68	255,459	218,516	171,528	15.02	11,420
1995	28,545.51	20,511	17,545	14,141	15.08	938
1996	48,395.71	34,345	29,378	24,341	15.14	1,608
1997	61,547.35	43,117	36,882	31,436	15.19	2,070
1998	13,263.32	9,161	7,836	6,886	15.25	452
1999	9,459.46	6,439	5,508	4,992	15.30	326
2000	2,121.03	1,421	1,216	1,139	15.35	74
2001	14,343.95	9,455	8,088	7,834	15.39	509
2002	11,795.11	7,635	6,531	6,562	15.44	425
2003	20,685.10	13,137	11,237	11,723	15.48	757
2004	49,807.12	30,993	26,511	28,775	15.52	1,854
2005	55,797.66	33,979	29,065	32,870	15.55	2,114



## KENTUCKY POWER COMPANY

## ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BIG SANDY						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 5-2041						
NET SALVAGE PERCENT.. -11						
2006	60,653.73	36,050	30,837	36,489	15.59	2,341
2007	74,927.75	43,405	37,128	46,042	15.62	2,948
2008	54,137.44	30,500	26,089	34,003	15.65	2,173
2009	14,929.91	8,157	6,977	9,595	15.68	612
2010	204,812.75	108,172	92,529	134,813	15.71	8,581
2011	6,582.89	3,348	2,864	4,443	15.74	282
2012	17,026.02	8,304	7,103	11,796	15.77	748
2013	187,592.65	87,349	74,717	133,511	15.79	8,455
2014	42,201.87	18,652	15,955	30,889	15.81	1,954
2015	275,601.78	114,735	98,143	207,775	15.83	13,125
2016	233,836.45	90,775	77,648	181,911	15.86	11,470
2017	164,563.25	59,045	50,506	132,159	15.87	8,328
2018	227,462.97	74,175	63,448	189,036	15.89	11,897
2019	413,981.96	120,105	102,736	356,784	15.91	22,425
2020	94,495.92	23,700	20,273	84,618	15.93	5,312
2021	103,182.43	21,482	18,375	96,157	15.94	6,032
2022	264,980.77	42,557	36,403	257,726	15.96	16,148
2024	302,307.05	14,852	12,704	322,857	15.98	20,204
	4,412,888.67	2,248,063	1,922,960	2,975,346		196,530

MITCHELL  
 INTERIM SURVIVOR CURVE.. IOWA 60-R2.5  
 PROBABLE RETIREMENT YEAR.. 12-2040  
 NET SALVAGE PERCENT.. -15

1971	1,673,860.91	1,513,677	1,399,340	525,600	12.05	43,618
1972	94,482.24	84,946	78,530	30,125	12.23	2,463
1973	8,659.50	7,741	7,156	2,802	12.40	226
1974	5,787.15	5,143	4,755	1,901	12.56	151
1975	12,049.50	10,645	9,841	4,016	12.72	316
1976	10,732.72	9,425	8,713	3,630	12.87	282
1977	14,360.50	12,531	11,584	4,930	13.02	379
1978	228,604.50	198,228	183,255	79,640	13.16	6,052
1979	23,118.00	19,919	18,414	8,171	13.29	615
1980	16,731.40	14,320	13,238	6,003	13.42	447
1982	44,671.50	37,709	34,861	16,512	13.66	1,209
1983	17,603.00	14,754	13,640	6,604	13.77	480
1984	66,687.04	55,493	51,301	25,389	13.87	1,830
1985	31,538.00	26,045	24,078	12,191	13.97	873

KENTUCKY POWER COMPANY

ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
1986	29,581.14	24,234	22,403	11,615	14.07	826
1987	18,949.50	15,398	14,235	7,557	14.16	534
1988	14,224.50	11,462	10,596	5,762	14.24	405
1989	25,725.92	20,550	18,998	10,587	14.32	739
1990	30,725.36	24,318	22,481	12,853	14.40	893
1991	10,025.26	7,859	7,265	4,264	14.47	295
1992	56,226.89	43,642	40,345	24,315	14.54	1,672
1993	33,178.50	25,480	23,555	14,600	14.61	999
1994	21,294.50	16,175	14,953	9,535	14.67	650
1995	20,262.32	15,214	14,065	9,237	14.73	627
1996	23,018.29	17,078	15,788	10,683	14.78	723
1997	21,878.76	16,026	14,815	10,345	14.83	698
1998	52,007.14	37,567	34,729	25,079	14.89	1,684
1999	16,324.29	11,625	10,747	8,026	14.93	538
2000	130,982.39	91,837	84,900	65,730	14.98	4,388
2001	14,931.30	10,301	9,523	7,648	15.02	509
2002	127,315.93	86,315	79,795	66,618	15.06	4,424
2003	49,524.84	32,952	30,463	26,491	15.10	1,754
2004	426,820.23	278,274	257,254	233,589	15.14	15,429
2005	121,930.06	77,804	71,927	68,293	15.17	4,502
2006	199,220.33	124,112	114,737	114,366	15.21	7,519
2007	188,247.61	114,341	105,704	110,781	15.24	7,269
2008	133,301.80	78,747	72,799	80,498	15.27	5,272
2009	1,911,447.87	1,095,478	1,012,730	1,185,435	15.30	77,479
2010	458,025.96	253,926	234,746	291,984	15.32	19,059
2011	359,612.43	192,137	177,624	235,931	15.35	15,370
2012	335,120.59	171,856	158,875	226,514	15.37	14,737
2013	308,957.54	151,213	139,791	215,510	15.40	13,994
2014	157,666.77	73,283	67,748	113,569	15.42	7,365
2015	165,512.34	72,502	67,026	123,314	15.44	7,987
2016	289,930.22	118,641	109,679	223,740	15.46	14,472
2017	258,560.84	97,654	90,278	207,067	15.48	13,376
2018	371,713.06	127,856	118,198	309,272	15.49	19,966
2019	222,873.23	68,259	63,103	193,201	15.51	12,457
2020	127,904.88	33,966	31,400	115,690	15.52	7,454
2021	132,696.11	29,218	27,011	125,590	15.54	8,082
2022	195,059.88	33,291	30,776	193,543	15.55	12,446

KENTUCKY POWER COMPANY

ACCOUNT 316.00 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
MITCHELL						
INTERIM SURVIVOR CURVE.. IOWA 60-R2.5						
PROBABLE RETIREMENT YEAR.. 12-2040						
NET SALVAGE PERCENT.. -15						
2023	1,007,616.68	115,273	106,566	1,052,193	15.57	67,578
2024	604,960.47	31,543	29,160	666,544	15.58	42,782
2025	44,284.15	421	389	50,538	15.58	3,244
	10,966,525.84	5,858,404	5,415,885	7,195,620		479,138
	15,379,414.51	8,106,467	7,338,845	10,170,966		675,668
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.1						4.39

KENTUCKY POWER COMPANY

ACCOUNT 350.10 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1975	38,729.00	24,358	21,647	17,082	27.83	614
1979	4,236,751.00	2,477,652	2,201,852	2,034,899	31.14	65,347
1980	259,692.00	148,926	132,348	127,344	31.99	3,981
1981	154,641.00	86,908	77,234	77,407	32.85	2,356
1982	148,856.00	81,930	72,810	76,046	33.72	2,255
1983	502,031.00	270,494	240,384	261,647	34.59	7,564
1984	294,262.00	155,055	137,795	156,467	35.48	4,410
1985	12,474,189.00	6,425,081	5,709,874	6,764,315	36.37	185,986
1986	82,584.00	41,546	36,921	45,663	37.27	1,225
1987	1,327.00	652	579	748	38.17	20
1988	3,265.00	1,563	1,389	1,876	39.09	48
1989	15,874.00	7,406	6,582	9,292	40.01	232
1990	104,145.00	47,310	42,044	62,101	40.93	1,517
1991	325,286.00	143,734	127,734	197,552	41.86	4,719
1992	75,805.00	32,545	28,922	46,883	42.80	1,095
1993	316,776.00	132,032	117,335	199,441	43.74	4,560
1994	321,828.00	130,060	115,582	206,246	44.69	4,615
1995	339,788.00	133,017	118,210	221,578	45.64	4,855
1996	126,373.00	47,854	42,527	83,846	46.60	1,799
1997	580,453.00	212,370	188,730	391,723	47.56	8,236
1998	1,280,236.00	452,013	401,697	878,539	48.52	18,107
1999	966,674.32	328,795	292,195	674,479	49.49	13,629
2000	321,568.93	105,217	93,505	228,064	50.46	4,520
2001	254,188.61	79,848	70,960	183,229	51.44	3,562
2002	6,166.71	1,857	1,650	4,517	52.41	86
2003	10,448.34	3,010	2,675	7,773	53.39	146
2004	33,991.00	9,350	8,309	25,682	54.37	472
2005	92,305.72	24,172	21,481	70,825	55.36	1,279
2006	103,998.38	25,875	22,995	81,003	56.34	1,438
2007	2,274.15	536	476	1,798	57.33	31
2008	1,564,567.17	347,960	309,227	1,255,340	58.32	21,525
2009	218,150.58	45,637	40,557	177,594	59.31	2,994
2010	26,745.34	5,242	4,658	22,087	60.30	366
2011	150,868.88	27,579	24,509	126,360	61.29	2,062
2012	873,785.14	148,194	131,698	742,087	62.28	11,915
2013	1,021,423.48	159,618	141,851	879,572	63.28	13,900
2014	3,150,627.48	450,760	400,585	2,750,042	64.27	42,789
2015	70,530.26	9,150	8,131	62,399	65.27	956
2016	16,082.33	1,872	1,664	14,418	66.27	218
2017	14,924.37	1,540	1,369	13,555	67.26	202
2018	846,165.19	76,045	67,580	778,585	68.26	11,406
2019	1,033,198.20	79,071	70,269	962,929	69.26	13,903

KENTUCKY POWER COMPANY

ACCOUNT 350.10 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2020	1,470,582.07	92,941	82,595	1,387,987	70.26	19,755
2021	180,690.73	9,035	8,029	172,662	71.25	2,423
2022	734,196.42	26,923	23,926	710,270	72.25	9,831
2023	598,742.81	13,969	12,414	586,329	73.25	8,004
2024	4,587,721.43	45,877	40,771	4,546,950	74.25	61,238
	40,033,509.04	13,172,579	11,706,275	28,327,234		572,191
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						49.5 1.43

KENTUCKY POWER COMPANY

ACCOUNT 351.20 COMPUTER SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2024	1,135,255.15	170,288	4,225	1,131,030	4.25	266,125
2025	229,002.03	5,496	136	228,866	4.88	46,899
	1,364,257.18	175,784	4,361	1,359,896		313,024
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.3						22.94

KENTUCKY POWER COMPANY

ACCOUNT 351.30 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	20,969.28	5,242	3,860	17,109	11.25	1,521
2022	181,785.15	33,327	24,541	157,244	12.25	12,836
2023	1,394.46	163	120	1,274	13.25	96
2024	48,717.61	2,436	1,794	46,924	14.25	3,293
	252,866.50	41,168	30,315	222,552		17,746
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5						7.02

KENTUCKY POWER COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S2						
NET SALVAGE PERCENT.. -15						
1942	7,335.00	7,592	4,821	3,614	5.50	657
1943	2,372.78	2,444	1,552	1,177	5.74	205
1944	2,137.00	2,190	1,391	1,067	5.99	178
1951	1,400.82	1,383	878	733	7.79	94
1952	92.00	90	57	49	8.07	6
1953	229.45	224	142	122	8.35	15
1954	25,366.93	24,595	15,618	13,554	8.63	1,571
1955	516.00	497	316	277	8.92	31
1956	381.00	365	232	206	9.22	22
1957	579.00	551	350	316	9.52	33
1958	973.00	919	584	535	9.83	54
1959	1,425.00	1,337	849	790	10.14	78
1960	2,810.13	2,617	1,662	1,570	10.46	150
1962	3,785.94	3,474	2,206	2,148	11.12	193
1963	15,544.00	14,154	8,988	8,888	11.45	776
1964	6,426.98	5,805	3,686	3,705	11.80	314
1965	297.00	266	169	173	12.15	14
1966	17,864.41	15,871	10,078	10,466	12.51	837
1967	20,168.91	17,763	11,279	11,915	12.88	925
1968	20,191.22	17,622	11,190	12,030	13.26	907
1969	1,252.00	1,083	688	752	13.64	55
1970	21,748.98	18,627	11,828	13,183	14.04	939
1971	4,372.00	3,708	2,355	2,673	14.44	185
1973	44,873.84	37,268	23,665	27,940	15.28	1,829
1974	473,847.05	389,272	247,183	297,741	15.71	18,952
1975	5,096.61	4,140	2,629	3,232	16.15	200
1976	63,345.00	50,860	32,295	40,552	16.60	2,443
1977	32,571.27	25,832	16,403	21,054	17.07	1,233
1978	125.00	98	62	82	17.54	5
1979	3,123.36	2,414	1,533	2,059	18.03	114
1980	76,315.17	58,194	36,952	50,810	18.53	2,742
1981	1,630,713.19	1,226,122	778,572	1,096,748	19.04	57,602
1982	180,530.35	133,738	84,922	122,688	19.57	6,269
1983	52,148.57	38,043	24,157	35,814	20.11	1,781
1984	114,981.84	82,559	52,424	79,805	20.66	3,863
1985	56,300.83	39,754	25,243	39,503	21.23	1,861
1986	155,981.30	108,246	68,735	110,643	21.81	5,073
1987	13,841.00	9,435	5,991	9,926	22.40	443
1988	2,933.00	1,962	1,246	2,127	23.01	92
1989	1,510.00	990	629	1,108	23.64	47
1990	65,391.44	42,003	26,671	48,529	24.28	1,999
1991	34,902.89	21,945	13,935	26,203	24.93	1,051



KENTUCKY POWER COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S2						
NET SALVAGE PERCENT.. -15						
1992	19,712.03	12,113	7,692	14,977	25.61	585
1993	354,340.62	212,637	135,022	272,470	26.30	10,360
1994	29,715.00	17,397	11,047	23,125	27.00	856
1995	111,414.67	63,551	40,354	87,773	27.72	3,166
1996	118,501.94	65,761	41,757	94,520	28.46	3,321
1997	156,092.16	84,140	53,428	126,078	29.22	4,315
1998	13,737.69	7,184	4,562	11,236	29.99	375
1999	11,766.15	5,959	3,784	9,747	30.78	317
2000	84,281.38	41,272	26,207	70,717	31.58	2,239
2002	806,045.35	366,739	232,874	694,078	33.24	20,881
2005	66,214.95	26,527	16,844	59,303	35.84	1,655
2007	79,210.73	28,752	18,257	72,835	37.64	1,935
2008	141,133.32	48,514	30,806	131,497	38.56	3,410
2009	144,271.68	46,757	29,690	136,222	39.50	3,449
2010	77,079.22	23,466	14,901	73,740	40.44	1,823
2011	64,619.13	18,389	11,677	62,635	41.39	1,513
2013	782.56	191	121	779	43.33	18
2016	5,626.83	1,027	652	5,819	46.27	126
2017	212,155.90	34,335	21,802	222,177	47.26	4,701
2018	597,123.53	84,154	53,437	633,255	48.26	13,122
2019	1,695,538.83	203,859	129,448	1,820,422	49.25	36,963
2020	2,324,845.42	230,890	146,612	2,526,960	50.25	50,288
2021	4,500,452.62	352,867	224,066	4,951,455	51.25	96,614
2022	129,742.25	7,460	4,737	144,467	52.25	2,765
2023	2,156,835.38	78,925	50,116	2,430,245	53.25	45,638
2024	13,086,650.43	205,277	130,349	14,919,299	54.25	275,010
	30,153,691.03	4,684,195	2,974,408	31,702,337		701,283
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.2						2.33

KENTUCKY POWER COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -15						
1953	7,575.00	7,312	5,162	3,549	8.03	442
1954	186,814.77	179,045	126,409	88,428	8.33	10,616
1955	897.00	854	603	429	8.63	50
1957	7,463.97	6,996	4,939	3,645	9.25	394
1958	577.00	537	379	285	9.57	30
1959	20,421.22	18,839	13,301	10,183	9.89	1,030
1960	23,448.97	21,454	15,147	11,819	10.22	1,156
1961	347.00	315	222	177	10.56	17
1962	0.03					
1963	441,160.35	393,184	277,596	229,738	11.25	20,421
1964	619.52	547	386	326	11.61	28
1965	11,627.32	10,168	7,179	6,192	11.98	517
1966	5,843.00	5,058	3,571	3,148	12.36	255
1967	199,698.71	171,138	120,827	108,827	12.74	8,542
1968	32,242.33	27,334	19,298	17,781	13.14	1,353
1969	2,054,665.13	1,722,529	1,216,139	1,146,726	13.55	84,629
1970	583,623.88	483,778	341,557	329,610	13.96	23,611
1971	1,774,237.06	1,453,153	1,025,954	1,014,419	14.39	70,495
1972	212,119.91	171,635	121,178	122,760	14.82	8,283
1973	210,797.52	168,383	118,882	123,535	15.27	8,090
1974	923,649.60	728,242	514,153	548,044	15.72	34,863
1975	762,985.14	593,320	418,896	458,537	16.19	28,322
1976	1,083,691.24	830,747	586,524	659,721	16.67	39,575
1977	1,268,425.41	958,067	676,414	782,275	17.16	45,587
1978	478,072.72	355,710	251,138	298,646	17.65	16,920
1979	651,409.96	477,041	336,800	412,321	18.16	22,705
1980	4,367,963.00	3,146,506	2,221,495	2,801,662	18.68	149,982
1981	3,997,889.75	2,831,186	1,998,873	2,598,700	19.21	135,279
1982	1,096,830.53	763,120	538,778	722,577	19.75	36,586
1983	211,808.00	144,686	102,151	141,428	20.30	6,967
1984	149,762.63	100,374	70,866	101,361	20.86	4,859
1985	661,145.77	434,445	306,727	453,591	21.43	21,166
1986	371,538.64	239,185	168,869	258,400	22.01	11,740
1987	1,658,632.44	1,045,270	737,981	1,169,446	22.60	51,745
1988	465,481.14	286,923	202,573	332,730	23.20	14,342
1989	3,320,429.73	2,000,127	1,412,129	2,406,365	23.81	101,065
1990	1,149,544.00	676,323	477,497	844,479	24.42	34,581
1991	3,666,025.26	2,103,749	1,485,288	2,730,641	25.05	109,008
1992	1,890,249.28	1,057,330	746,496	1,427,291	25.68	55,580
1993	4,904,518.97	2,671,197	1,885,917	3,754,280	26.32	142,640
1994	2,587,559.04	1,370,009	967,253	2,008,440	26.98	74,442
1995	919,783.40	473,238	334,115	723,636	27.63	26,190

KENTUCKY POWER COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -15						
1996	2,203,764.19	1,099,899	776,550	1,757,779	28.30	62,112
1997	32,638,115.68	15,786,730	11,145,739	26,388,094	28.97	910,877
1998	10,666,906.29	4,990,192	3,523,173	8,743,769	29.66	294,800
1999	1,226,236.35	554,480	391,474	1,018,698	30.34	33,576
2000	2,051,150.57	894,466	631,510	1,727,313	31.04	55,648
2001	3,382,615.04	1,420,631	1,002,993	2,887,014	31.74	90,958
2002	3,332,573.36	1,345,193	949,733	2,882,726	32.45	88,836
2003	3,211,600.50	1,243,178	877,708	2,815,633	33.17	84,885
2004	2,372,663.84	879,143	620,692	2,107,871	33.89	62,197
2005	1,867,428.27	660,584	466,385	1,681,158	34.62	48,560
2006	10,916,194.27	3,678,212	2,596,889	9,956,734	35.35	281,661
2007	1,594,683.01	510,187	360,202	1,473,683	36.09	40,834
2008	13,148,564.30	3,982,832	2,811,957	12,308,892	36.83	334,208
2009	4,545,041.98	1,298,337	916,651	4,310,147	37.58	114,693
2010	4,859,515.04	1,304,342	920,891	4,667,551	38.33	121,773
2011	7,713,966.63	1,935,666	1,366,618	7,504,444	39.09	191,979
2012	11,178,906.97	2,609,716	1,842,510	11,013,233	39.85	276,367
2013	4,510,516.27	973,099	687,027	4,500,067	40.62	110,785
2014	8,523,232.02	1,685,895	1,190,275	8,611,442	41.40	208,006
2015	4,915,159.13	885,171	624,948	5,027,485	42.17	119,219
2016	4,256,933.63	689,283	486,647	4,408,827	42.96	102,626
2017	6,405,895.49	922,321	651,177	6,715,603	43.74	153,535
2018	9,905,697.74	1,246,236	879,867	10,511,685	44.53	236,058
2019	17,618,735.71	1,892,428	1,336,091	18,925,455	45.33	417,504
2020	10,530,041.26	937,279	661,737	11,447,810	46.13	248,164
2021	33,920,997.40	2,387,360	1,685,523	37,323,624	46.94	795,135
2022	16,324,050.88	844,770	596,424	18,176,235	47.75	380,654
2023	15,176,873.06	502,658	354,887	17,098,517	48.56	352,111
2024	22,242,640.16	317,180	223,935	25,355,101	49.38	513,469
2025	4,484.45	10	7	5,150	49.90	103
	313,606,758.83	85,606,532	60,439,882	300,207,891		8,135,436

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.9 2.59

KENTUCKY POWER COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. -40						
1938	7,093.00	9,275	9,113	817	4.62	177
1939	254.73	332	326	31	4.89	6
1940	678.05	879	864	85	5.16	16
1942	92,751.46	119,242	117,166	12,686	5.72	2,218
1944	757.10	965	948	112	6.30	18
1954	17,562.80	21,110	20,742	3,846	9.90	388
1956	3,284.90	3,887	3,819	780	10.84	72
1959	276,380.23	318,225	312,684	74,248	12.43	5,973
1963	611,134.55	674,084	662,346	193,242	14.85	13,013
1964	3,382.58	3,687	3,623	1,113	15.50	72
1965	78,509.95	84,524	83,052	26,862	16.17	1,661
1966	19,067.00	20,272	19,919	6,775	16.84	402
1967	134,705.22	141,359	138,897	49,690	17.53	2,835
1968	643,077.75	665,967	654,370	245,939	18.22	13,498
1970	3,879,109.75	3,907,047	3,839,012	1,591,742	19.64	81,046
1971	1,772.00	1,759	1,728	753	20.36	37
1972	8,397,064.84	8,213,958	8,070,925	3,684,966	21.09	174,726
1973	112,843.00	108,690	106,797	51,183	21.84	2,344
1974	20,383.00	19,327	18,990	9,546	22.59	423
1975	72,763.00	67,874	66,692	35,176	23.36	1,506
1976	97,496.26	89,423	87,866	48,629	24.14	2,014
1977	28,600.00	25,786	25,337	14,703	24.92	590
1978	39,851.00	35,292	34,677	21,114	25.72	821
1982	183,077.97	150,051	147,438	108,871	29.02	3,752
1985	59,889,883.00	45,995,310	45,194,377	38,651,459	31.60	1,223,147
1986	646,703.00	485,286	476,836	428,548	32.48	13,194
1990	837.22	568	558	614	36.07	17
1991	15.00	10	10	11	36.99	
1992	40,368.00	25,908	25,457	31,058	37.91	819
1993	182,665.00	113,836	111,854	143,877	38.84	3,704
1995	315,634.00	184,837	181,618	260,270	40.72	6,392
1996	341,182.47	193,384	190,017	287,638	41.66	6,904
1997	860,276.00	471,084	462,881	741,505	42.62	17,398
1998	4,324,133.64	2,285,728	2,245,925	3,807,862	43.57	87,396
1999	4,714,115.73	2,401,389	2,359,573	4,240,189	44.53	95,221
2000	572,144.09	280,351	275,469	525,533	45.50	11,550
2001	998,858.85	470,059	461,874	936,528	46.47	20,153
2002	96,142.36	43,380	42,625	91,974	47.44	1,939
2003	27,462.95	11,859	11,652	26,796	48.41	554
2004	5,437.45	2,241	2,202	5,410	49.39	110
2005	16,025.73	6,292	6,182	16,254	50.37	323
2008	2,734,526.09	911,680	895,804	2,932,533	53.33	54,988

KENTUCKY POWER COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. -40						
2009	143,884.30	45,122	44,336	157,102	54.32	2,892
2010	25,112.65	7,383	7,254	27,904	55.30	505
2012	38,139.84	9,695	9,526	43,870	57.29	766
2013	105,798.24	24,799	24,367	123,751	58.28	2,123
2014	4,489,230.45	962,473	945,714	5,339,209	59.28	90,068
2016	9,042.01	1,579	1,552	11,107	61.27	181
2018	3,983,262.48	536,968	527,618	5,048,949	63.26	79,813
2021	1,010,862.22	75,813	74,493	1,340,714	66.25	20,237
2022	804,638.77	44,260	43,489	1,083,005	67.25	16,104
2024	23,139,612.23	346,955	340,913	32,054,544	69.25	462,882
	124,237,593.91	70,621,264	69,391,507	104,541,124		2,526,988
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.4 2.03						

KENTUCKY POWER COMPANY

ACCOUNT 355.00 POLES AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -40						
1944	289.99	406	406			
1962	0.01					
1965	8,262.29	10,524	11,176	391	4.06	96
1967	1,241.04	1,561	1,658	79	4.58	17
1968	0.01					
1969	1,217.15	1,509	1,603	101	5.14	20
1972	0.01					
1973	435.37	523	555	55	6.37	9
1974	0.01					
1975	130,439.00	153,884	163,425	19,190	7.08	2,710
1976	16,031.31	18,723	19,884	2,560	7.46	343
1977	319,049.05	368,551	391,401	55,268	7.87	7,023
1978	40,411.77	46,154	49,016	7,560	8.29	912
1979	3,588.61	4,049	4,300	724	8.73	83
1980	3,928.85	4,376	4,647	853	9.20	93
1981	26,604.94	29,235	31,048	6,199	9.68	640
1982	195,823.58	212,074	225,223	48,930	10.19	4,802
1983	4,333.79	4,622	4,909	1,158	10.72	108
1984	13,104.93	13,752	14,605	3,742	11.27	332
1985	84,008.09	86,692	92,067	25,544	11.83	2,159
1986	569,474.65	577,220	613,008	184,257	12.42	14,836
1987	26,740.27	26,596	28,245	9,191	13.03	705
1988	80,717.30	78,701	83,581	29,423	13.66	2,154
1989	200,981.63	191,959	203,861	77,513	14.30	5,420
1990	1,926.10	1,800	1,912	785	14.96	52
1991	623,920.65	569,899	605,233	268,256	15.64	17,152
1992	1,023,744.06	913,133	969,748	463,494	16.33	28,383
1993	1,299,407.96	1,130,306	1,200,386	618,785	17.04	36,314
1994	2,324,095.98	1,969,583	2,091,699	1,162,035	17.76	65,430
1995	488,529.00	402,766	427,738	256,203	18.50	13,849
1996	700,496.06	561,173	595,966	384,728	19.25	19,986
1997	1,922,981.23	1,495,045	1,587,739	1,104,435	20.01	55,194
1998	4,511,082.42	3,399,137	3,609,886	2,705,629	20.78	130,204
1999	6,809,640.81	4,963,806	5,271,566	4,261,931	21.57	197,586
2000	1,741,644.81	1,226,198	1,302,223	1,136,080	22.37	50,786
2001	2,225,800.63	1,510,976	1,604,658	1,511,463	23.18	65,205
2002	1,918,792.20	1,253,620	1,331,345	1,354,964	24.00	56,457
2003	495,598.34	310,992	330,274	363,564	24.83	14,642
2004	1,327,254.63	797,762	847,224	1,010,932	25.68	39,367
2005	1,336,457.14	767,950	815,564	1,055,476	26.53	39,784
2006	1,765,844.97	967,439	1,027,421	1,444,762	27.39	52,748
2007	502,292.50	261,439	277,648	425,562	28.27	15,053

KENTUCKY POWER COMPANY

ACCOUNT 355.00 POLES AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -40						
2008	8,559,648.56	4,220,831	4,482,526	7,500,982	29.15	257,324
2009	1,451,167.43	675,397	717,272	1,314,362	30.04	43,754
2010	1,417,786.72	620,163	658,614	1,326,287	30.94	42,866
2011	8,648,311.73	3,538,094	3,757,459	8,350,177	31.85	262,172
2012	13,210,669.35	5,026,554	5,338,204	13,156,733	32.77	401,487
2013	3,192,038.56	1,122,174	1,191,750	3,277,104	33.70	97,243
2014	18,073,745.83	5,830,880	6,192,399	19,110,845	34.63	551,858
2015	3,754,214.40	1,101,426	1,169,715	4,086,185	35.57	114,877
2016	2,031,371.88	535,908	569,135	2,274,786	36.52	62,289
2017	3,780,341.86	885,590	940,497	4,351,982	37.47	116,146
2018	9,147,312.44	1,869,711	1,985,635	10,820,602	38.43	281,567
2019	23,726,549.88	4,141,185	4,397,942	28,819,228	39.39	731,638
2020	30,770,142.45	4,451,270	4,727,253	38,350,946	40.35	950,457
2021	21,438,589.24	2,447,944	2,599,718	27,414,307	41.33	663,303
2022	10,144,835.84	852,166	905,001	13,297,769	42.30	314,368
2023	16,860,794.10	902,187	958,123	22,646,989	43.28	523,267
2024	36,828,629.69	847,648	900,203	50,659,879	44.26	1,144,597
2025	2,367,173.82	8,848	9,397	3,304,646	44.88	73,633
	248,149,516.92	63,412,111	67,343,691	280,065,633		7,573,500
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						37.0 3.05

KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -40						
1922	11.95	16	17			
1923	10.00	14	14			
1924	3.00	4	4			
1925	16.00	22	22			
1926	74.00	99	104			
1927	42.00	56	59			
1928	30.00	40	42			
1929	137.00	182	192			
1930	40.01	53	56			
1931	19.00	25	27			
1932	19.00	25	27			
1933	14.00	18	20			
1934	29.72	39	42			
1935	362.06	468	507			
1936	502.42	647	703			
1937	682.49	875	955			
1938	67.00	86	94			
1939	476.00	605	666			
1940	69,747.08	88,227	97,646			
1941	1,187.59	1,496	1,663			
1942	279,897.24	350,860	391,856			
1943	285.42	356	400			
1944	4,633.00	5,753	6,486			
1945	1,167.66	1,443	1,635			
1946	5,928.00	7,285	8,299			
1947	102.01	125	143			
1948	131.00	159	182			
1949	558.00	675	772	1	8.55	
1950	2,803.18	3,369	3,854	9	8.87	1
1951	13,420.00	16,028	18,337	70	9.20	8
1952	9,120.08	10,823	12,382	451	9.55	47
1953	21,260.94	25,062	28,673	386	9.90	39
1954	77,518.94	90,744	103,817	1,092	10.27	106
1955	3,834.00	4,455	5,097	4,710	10.65	442
1956	10,591.17	12,216	13,976	271	11.05	25
1957	6,069.52	6,944	7,944	852	11.45	74
1958	346,761.88	393,529	450,224	553	11.88	47
1959	194,332.04	218,615	250,111	35,243	12.31	2,863
1960	20,687.10	23,067	26,390	21,954	12.77	1,719
1961	7,495.12	8,280	9,473	2,572	13.23	194
1962	78,753.70	86,151	98,563	1,020	13.71	74
1963	513,989.32	556,628	636,821	11,692	14.21	823
				82,764	14.72	5,623



KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -40						
1964	36,926.54	39,576	45,278	6,419	15.24	421
1965	482,738.59	511,762	585,491	90,343	15.78	5,725
1966	44,037.73	46,155	52,804	8,849	16.34	542
1967	494,486.92	512,288	586,093	106,189	16.90	6,283
1968	1,167,515.26	1,194,966	1,367,123	267,398	17.48	15,297
1969	184,718.80	186,675	213,569	45,037	18.08	2,491
1970	8,033,344.86	8,012,812	9,167,208	2,079,475	18.69	111,261
1971	988,275.47	972,550	1,112,664	270,922	19.31	14,030
1972	143,429.71	139,202	159,257	41,545	19.94	2,084
1973	32,084.00	30,696	35,118	9,800	20.58	476
1974	16,555.19	15,604	17,852	5,325	21.24	251
1975	158,228.81	146,850	168,006	53,514	21.91	2,442
1976	92,042.97	84,076	96,189	32,671	22.59	1,446
1977	509,705.00	458,016	524,002	189,585	23.28	8,144
1978	1,856,964.17	1,640,650	1,877,016	722,734	23.98	30,139
1979	59,325.91	51,507	58,928	24,128	24.69	977
1980	250,367.48	213,491	244,248	106,266	25.41	4,182
1981	678,498.00	567,896	649,712	300,185	26.14	11,484
1982	1,675,551.26	1,375,701	1,573,897	771,875	26.88	28,716
1983	35,130.44	28,276	32,350	16,833	27.63	609
1984	96,445.00	76,049	87,005	48,018	28.39	1,691
1985	45,818,930.05	35,369,098	40,464,680	23,681,822	29.16	812,134
1986	823,787.17	622,253	711,900	441,402	29.93	14,748
1987	112,721.74	83,226	95,216	62,594	30.72	2,038
1988	182,920.00	131,944	150,953	105,135	31.51	3,337
1989	271,231.00	190,970	218,483	161,240	32.31	4,990
1990	344,978.73	236,878	271,005	211,965	33.12	6,400
1991	594,537.91	397,865	455,185	377,168	33.93	11,116
1992	1,998,579.76	1,301,719	1,489,256	1,308,756	34.76	37,651
1993	1,632,829.82	1,034,306	1,183,317	1,102,645	35.59	30,982
1994	3,246,840.90	1,997,963	2,285,807	2,259,770	36.43	62,030
1995	1,023,612.00	611,141	699,187	733,870	37.28	19,685
1996	1,336,378.48	773,405	884,829	986,101	38.13	25,862
1997	689,875.00	386,475	442,154	523,671	38.99	13,431
1998	2,747,776.42	1,487,860	1,702,214	2,144,673	39.86	53,805
1999	11,987,484.06	6,266,242	7,169,012	9,613,466	40.73	236,029
2000	1,804,555.09	909,117	1,040,092	1,486,285	41.61	35,719
2001	985,232.38	477,453	546,239	833,086	42.50	19,602
2002	422,998.73	196,882	225,247	366,951	43.39	8,457
2003	653,964.64	291,713	333,740	581,810	44.29	13,136
2004	241,394.25	102,947	117,778	220,174	45.20	4,871
2005	859,356.84	349,645	400,018	803,082	46.11	17,417

KENTUCKY POWER COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -40						
2006	223,434.39	86,479	98,938	213,870	47.03	4,548
2007	388,254.21	142,580	163,121	380,435	47.95	7,934
2008	8,153,691.76	2,830,962	3,238,815	8,176,353	48.88	167,274
2009	816,705.47	267,198	305,693	837,695	49.81	16,818
2010	918,519.56	281,914	322,529	963,398	50.75	18,983
2011	4,328,017.47	1,240,747	1,419,500	4,639,724	51.69	89,761
2012	5,939,106.44	1,581,050	1,808,830	6,505,919	52.64	123,593
2013	1,737,739.72	427,060	488,586	1,944,250	53.59	36,280
2014	13,607,780.98	3,065,670	3,507,337	15,543,556	54.54	284,994
2015	1,706,552.90	349,178	399,484	1,989,690	55.50	35,850
2016	841,565.71	154,791	177,092	1,001,100	56.46	17,731
2017	1,483,582.04	241,889	276,738	1,800,277	57.43	31,347
2018	1,490,333.65	211,860	242,382	1,844,085	58.40	31,577
2019	9,018,290.40	1,093,630	1,251,188	11,374,419	59.37	191,585
2020	7,720,806.78	774,906	886,546	9,922,583	60.34	164,445
2021	9,647,186.15	764,713	874,884	12,631,177	61.32	205,988
2022	4,057,868.72	235,989	269,987	5,411,029	62.30	86,854
2023	3,495,046.19	129,470	148,123	4,744,942	63.28	74,983
2024	16,127,722.70	256,947	293,965	22,284,847	64.26	346,792
2025	322,016.73	834	954	449,869	64.88	6,934
	188,513,388.69	85,577,331	97,893,109	166,025,635		3,638,487
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.6						1.93

KENTUCKY POWER COMPANY

ACCOUNT 357.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S3						
NET SALVAGE PERCENT.. 0						
1997	11,590.00	6,800	7,647	3,943	18.60	212
2019	302,258.60	38,623	43,433	258,826	39.25	6,594
2020	197,103.72	20,806	23,397	173,707	40.25	4,316
2022	4,662,449.81	284,922	320,410	4,342,040	42.25	102,770
2023	446,747.09	17,374	19,538	427,209	43.25	9,878
2024	523,218.05	8,722	9,808	513,410	44.25	11,602
2025	120,180.00	321	361	119,819	44.88	2,670
	6,263,547.27	377,568	424,594	5,838,953		138,042
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.3						2.20

KENTUCKY POWER COMPANY

ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. 0						
1983	106,066.00	80,799	75,561	30,505	10.72	2,846
2019	273,035.03	34,039	31,832	241,203	39.39	6,123
2020	2,352.53	243	227	2,126	40.35	53
2021	116,168.98	9,475	8,861	107,308	41.33	2,596
2023	43,614.70	1,667	1,559	42,056	43.28	972
2024	45,633.35	750	701	44,932	44.26	1,015
2025	24,764.17	66	62	24,702	44.88	550
	611,634.76	127,039	118,803	492,832		14,155
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.8 2.31						

KENTUCKY POWER COMPANY

ACCOUNT 360.10 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1979	1,913,234.00	1,118,859	1,753,610	159,624	31.14	5,126
1980	24,590.00	14,102	22,102	2,488	31.99	78
1981	38,508.00	21,641	33,918	4,590	32.85	140
1982	48,942.00	26,938	42,220	6,722	33.72	199
1983	66,861.00	36,025	56,463	10,398	34.59	301
1984	25,934.00	13,665	21,417	4,517	35.48	127
1985	20,719.00	10,672	16,726	3,993	36.37	110
1986	47,346.00	23,818	37,330	10,016	37.27	269
1987	19,016.00	9,338	14,636	4,380	38.17	115
1988	26,380.00	12,631	19,797	6,583	39.09	168
1989	31,201.00	14,556	22,814	8,387	40.01	210
1990	54,838.00	24,911	39,044	15,794	40.93	386
1991	76,154.00	33,650	52,740	23,414	41.86	559
1992	94,764.00	40,685	63,766	30,998	42.80	724
1993	49,128.00	20,477	32,094	17,034	43.74	389
1994	14,023.00	5,667	8,882	5,141	44.69	115
1995	106,401.00	41,653	65,284	41,117	45.64	901
1996	53,347.00	20,201	31,661	21,686	46.60	465
1997	219,539.50	80,323	125,892	93,648	47.56	1,969
1998	108,643.00	38,359	60,121	48,522	48.52	1,000
1999	3,677.00	1,251	1,961	1,716	49.49	35
2000	315,016.21	103,073	161,549	153,467	50.46	3,041
2001	106,531.58	33,465	52,450	54,082	51.44	1,051
2002	131,307.26	39,550	61,988	69,319	52.41	1,323
2003	188,981.14	54,451	85,342	103,639	53.39	1,941
2004	100,775.44	27,720	43,446	57,329	54.37	1,054
2005	117,956.02	30,889	48,413	69,543	55.36	1,256
2006	174,821.73	43,496	68,172	106,650	56.34	1,893
2007	183,741.67	43,290	67,849	115,893	57.33	2,022
2008	149,054.01	33,150	51,957	97,097	58.32	1,665
2009	202,743.04	42,414	66,476	136,267	59.31	2,298
2010	160,979.62	31,552	49,452	111,528	60.30	1,850
2011	162,768.67	29,754	46,634	116,135	61.29	1,895
2012	161,618.21	27,410	42,961	118,657	62.28	1,905
2013	146,016.28	22,818	35,763	110,253	63.28	1,742
2018	212,131.97	19,064	29,880	182,252	68.26	2,670
2019	142,366.32	10,895	17,076	125,290	69.26	1,809
2020	185,307.51	11,711	18,355	166,953	70.26	2,376

KENTUCKY POWER COMPANY

ACCOUNT 360.10 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
2022	366,017.67	13,422	21,036	344,982	72.25	4,775
2023	122,490.49	2,858	4,480	118,010	73.25	1,611
2024	150,611.90	1,506	2,360	148,252	74.25	1,997
	6,524,482.24	2,231,910	3,498,117	3,026,365		53,560
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 56.5 0.82						

KENTUCKY POWER COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. -20						
1938	12,655.04	13,249	15,186			
1940	3,269.79	3,393	3,924			
1941	0.01					
1942	977.00	1,004	1,172			
1943	1,672.00	1,711	2,006			
1945	757.00	767	908			
1946	42.00	42	50			
1947	907.00	909	1,088			
1948	5,174.00	5,155	6,209			
1949	2,700.01	2,674	3,240			
1950	3,120.63	3,072	3,745			
1951	0.26					
1952	0.04					
1953	8,184.00	7,896	9,821			
1954	4,906.00	4,700	5,887			
1955	701.00	666	835	6	13.50	
1956	4,629.41	4,367	5,476	79	13.90	6
1957	5,945.84	5,563	6,976	159	14.32	11
1959	193.00	177	222	10	15.19	1
1960	291.00	265	332	17	15.65	1
1961	1,585.00	1,430	1,793	109	16.12	7
1962	190.00	170	213	15	16.60	1
1963	5,202.00	4,601	5,769	473	17.09	28
1964	495.00	433	543	51	17.60	3
1965	1,812.70	1,569	1,967	208	18.12	11
1966	23,923.10	20,466	25,663	3,045	18.66	163
1967	13,906.00	11,755	14,740	1,947	19.21	101
1968	20,793.00	17,363	21,772	3,180	19.77	161
1969	6,970.00	5,747	7,206	1,158	20.34	57
1970	13,257.00	10,788	13,527	2,381	20.92	114
1971	60,176.00	48,304	60,570	11,641	21.52	541
1972	35,067.65	27,754	34,802	7,279	22.13	329
1973	38,223.46	29,821	37,394	8,474	22.74	373
1974	61,638.00	47,372	59,401	14,565	23.37	623
1975	71,558.00	54,151	67,902	17,968	24.01	748
1976	5,797.07	4,317	5,413	1,543	24.66	63
1977	78,975.11	57,853	72,544	22,226	25.32	878
1978	37,130.00	26,740	33,530	11,026	25.99	424
1979	5,950.00	4,212	5,282	1,858	26.66	70
1980	335,345.08	233,090	292,280	110,134	27.35	4,027
1981	92,740.00	63,263	79,328	31,960	28.05	1,139
1982	61,898.31	41,424	51,943	22,335	28.75	777

KENTUCKY POWER COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. -20						
1983	6,957.90	4,564	5,723	2,626	29.47	89
1984	10,503.00	6,750	8,464	4,140	30.19	137
1985	118,947.00	74,838	93,842	48,894	30.92	1,581
1986	146,952.01	90,478	113,454	62,888	31.65	1,987
1987	100,005.30	60,188	75,472	44,534	32.40	1,375
1988	35,634.00	20,953	26,274	16,487	33.15	497
1989	33,374.00	19,156	24,020	16,029	33.91	473
1990	31,974.83	17,898	22,443	15,927	34.68	459
1991	337,179.00	183,881	230,575	174,040	35.46	4,908
1992	112,019.00	59,477	74,580	59,843	36.24	1,651
1993	231,077.28	119,322	149,622	127,671	37.03	3,448
1994	104,061.00	52,216	65,476	59,397	37.82	1,571
1995	584,286.09	284,447	356,679	344,464	38.63	8,917
1996	26,060.46	12,297	15,420	15,853	39.44	402
1997	38,520.96	17,601	22,071	24,154	40.25	600
1998	26,575.03	11,736	14,716	17,174	41.08	418
1999	387,262.85	165,081	207,001	257,714	41.91	6,149
2000	100,752.20	41,404	51,918	68,985	42.74	1,614
2001	7,027.54	2,779	3,485	4,948	43.58	114
2002	38,513.72	14,626	18,340	27,876	44.43	627
2003	395,783.91	144,088	180,677	294,264	45.28	6,499
2005	8,634.85	2,868	3,596	6,766	47.01	144
2008	138,356.05	39,259	49,228	116,799	49.63	2,353
2009	26,516.60	7,089	8,889	22,931	50.52	454
2010	2,118.53	532	667	1,875	51.41	36
2011	97,058.07	22,756	28,535	87,935	52.30	1,681
2014	11,052.88	2,038	2,556	10,707	55.01	195
2016	123,711.16	18,637	23,370	125,083	56.84	2,201
2017	171,965.45	22,984	28,820	177,539	57.76	3,074
2018	625,548.12	72,986	91,520	659,138	58.68	11,233
2019	1,657,239.15	164,902	206,777	1,781,910	59.61	29,893
2020	315,113.30	25,948	32,537	345,599	60.54	5,709
2021	2,241,158.78	146,061	183,151	2,506,240	61.47	40,772
2022	39,329.27	1,881	2,359	44,836	62.41	718
2023	2,924,474.67	89,068	111,686	3,397,684	63.35	53,634
2024	7,030,326.74	92,125	115,518	8,320,874	64.29	129,427
2025	308,122.83	684	858	368,889	64.88	5,686
	19,622,951.04	2,881,831	3,610,978	19,936,563		341,383

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 58.4 1.74



KENTUCKY POWER COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1						
NET SALVAGE PERCENT.. -15						
1957	12,126.46	12,914	12,792	1,153	2.81	410
1961	10,069.89	10,361	10,263	1,317	4.00	329
1962	10,263.94	10,465	10,366	1,438	4.31	334
1963	25,253.01	25,510	25,270	3,771	4.62	816
1964	4,565.01	4,569	4,526	724	4.93	147
1965	987.00	978	969	166	5.26	32
1966	53,585.38	52,574	52,078	9,545	5.58	1,711
1967	108,639.62	105,472	104,478	20,458	5.92	3,456
1968	72,571.15	69,708	69,051	14,406	6.26	2,301
1969	20,274.01	19,266	19,084	4,231	6.60	641
1970	131,815.38	123,823	122,656	28,932	6.96	4,157
1971	137,418.28	127,590	126,387	31,644	7.32	4,323
1972	392,901.80	360,516	357,117	94,720	7.68	12,333
1973	318,998.70	289,036	286,311	80,538	8.06	9,992
1974	154,198.21	137,942	136,642	40,686	8.44	4,821
1975	51,748.95	45,698	45,267	14,244	8.82	1,615
1976	62,475.59	54,415	53,902	17,945	9.22	1,946
1977	371,774.80	319,305	316,295	111,246	9.62	11,564
1978	704,256.73	596,123	590,503	219,392	10.03	21,874
1979	312,297.20	260,378	257,923	101,219	10.45	9,686
1980	1,432,874.66	1,176,451	1,165,360	482,446	10.87	44,383
1981	364,670.83	294,663	291,885	127,486	11.30	11,282
1982	871,455.80	692,292	685,766	316,408	11.75	26,928
1983	186,463.63	145,645	144,272	70,161	12.19	5,756
1984	630,299.57	483,551	478,992	245,853	12.65	19,435
1985	560,934.97	422,357	418,375	226,700	13.12	17,279
1986	1,119,230.51	826,804	819,010	468,105	13.59	34,445
1987	1,172,132.01	848,495	840,496	507,456	14.08	36,041
1988	247,110.05	175,218	173,566	110,611	14.57	7,592
1989	390,763.16	271,163	268,607	180,771	15.07	11,995
1990	315,047.31	213,760	211,745	150,559	15.58	9,664
1991	1,220,095.12	808,640	801,017	602,092	16.10	37,397
1992	866,579.06	560,439	555,156	441,410	16.63	26,543
1993	2,332,919.12	1,470,635	1,456,771	1,226,086	17.17	71,409
1994	940,573.83	577,260	571,818	509,842	17.72	28,772
1995	3,499,394.90	2,089,459	2,069,761	1,954,543	18.27	106,981
1996	1,544,599.46	895,623	887,180	889,109	18.84	47,193
1997	1,536,715.09	864,083	855,937	911,285	19.42	46,925
1998	757,947.16	412,878	408,986	462,653	20.00	23,133
1999	637,006.36	335,628	332,464	400,093	20.59	19,431
2000	1,559,740.22	793,480	786,000	1,007,701	21.19	47,555
2001	1,841,796.51	902,974	894,461	1,223,605	21.80	56,129

KENTUCKY POWER COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-R1						
NET SALVAGE PERCENT.. -15						
2002	608,862.23	287,079	284,373	415,819	22.42	18,547
2003	694,841.70	314,369	311,405	487,663	23.05	21,157
2004	733,839.37	318,021	315,023	528,892	23.68	22,335
2005	2,108,993.22	873,123	864,892	1,560,450	24.32	64,163
2006	2,492,545.45	983,643	974,370	1,892,057	24.96	75,804
2007	2,658,772.74	996,132	986,741	2,070,848	25.62	80,829
2008	8,668,662.18	3,074,627	3,045,642	6,923,320	26.28	263,444
2009	5,267,297.90	1,763,004	1,746,384	4,311,009	26.94	160,023
2010	1,275,703.90	401,123	397,342	1,069,717	27.61	38,744
2011	7,617,645.07	2,240,795	2,219,671	6,540,621	28.28	231,281
2012	8,262,424.42	2,260,380	2,239,071	7,262,717	28.96	250,784
2013	7,419,727.95	1,877,191	1,859,494	6,673,193	29.64	225,141
2014	7,644,864.81	1,774,495	1,757,766	7,033,829	30.33	231,910
2015	1,662,427.77	351,158	347,848	1,563,944	31.02	50,417
2016	4,135,414.14	787,215	779,794	3,975,932	31.71	125,384
2017	10,525,058.68	1,780,593	1,763,807	10,340,010	32.41	319,038
2018	7,032,663.27	1,040,708	1,030,897	7,056,666	33.11	213,128
2019	17,652,006.32	2,232,979	2,211,928	18,087,879	33.82	534,828
2020	4,139,185.68	433,404	429,318	4,330,746	34.54	125,383
2021	10,717,289.62	891,952	883,543	11,441,340	35.25	324,577
2022	4,148,805.04	253,633	251,242	4,519,884	35.98	125,622
2023	6,439,298.77	251,406	249,036	7,156,158	36.71	194,938
2024	21,720,954.80	368,192	364,721	24,614,377	37.44	657,435
2025	87,579.82	239	237	100,480	37.91	2,650
	170,699,435.29	43,443,602	43,034,050	153,270,301		5,186,318
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						29.6 3.04

KENTUCKY POWER COMPANY

ACCOUNT 363.20 COMPUTER SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2025	139,902.88	3,358	2,266	137,637	4.88	28,204
	139,902.88	3,358	2,266	137,637		28,204
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.9						20.16

KENTUCKY POWER COMPANY

ACCOUNT 363.30 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	4,942.97	577	61	4,882	13.25	368
2024	113,569.87	5,678	599	112,971	14.25	7,928
2025	1,416,231.93	11,330	1,195	1,415,037	14.88	95,097
	1,534,744.77	17,585	1,855	1,532,890		103,393
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.8						6.74

KENTUCKY POWER COMPANY

ACCOUNT 363.36 COMMUNICATION EQUIPMENT - AMI

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	828,337.45	648,862	490,522	337,815	3.25	103,943
2014	257,349.63	184,435	139,428	117,922	4.25	27,746
2015	38,150.84	24,798	18,747	19,404	5.25	3,696
2016	21,082.21	12,298	9,297	11,785	6.25	1,886
2017	19,305.87	9,975	7,541	11,765	7.25	1,623
2018	91,615.91	41,227	31,166	60,450	8.25	7,327
2019	77,247.73	29,611	22,385	54,863	9.25	5,931
2021	148,164.80	37,041	28,002	120,163	11.25	10,681
2022	23,666.20	4,339	3,280	20,386	12.25	1,664
2023	120,954.00	14,112	10,669	110,285	13.25	8,323
	1,625,874.64	1,006,698	761,037	864,838		172,820

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.0 10.63

KENTUCKY POWER COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -60						
1954	3,739.94	4,987	5,006	978	8.33	117
1963	2,416.00	2,996	3,007	859	11.25	76
1964	4,755.00	5,841	5,863	1,745	11.61	150
1965	11,699.50	14,234	14,287	4,432	11.98	370
1966	19,463.90	23,444	23,531	7,611	12.36	616
1967	34,477.56	41,108	41,261	13,903	12.74	1,091
1968	53,445.59	63,040	63,275	22,238	13.14	1,692
1969	75,602.73	88,183	88,512	32,452	13.55	2,395
1970	105,647.17	121,841	122,296	46,739	13.96	3,348
1971	137,358.30	156,523	157,107	62,666	14.39	4,355
1972	253,120.17	284,953	286,016	118,976	14.82	8,028
1973	341,140.45	379,130	380,545	165,280	15.27	10,824
1974	394,344.43	432,580	434,194	196,757	15.72	12,516
1975	477,569.97	516,693	518,621	245,491	16.19	15,163
1976	734,243.49	783,115	786,037	388,753	16.67	23,321
1977	1,158,174.73	1,217,103	1,221,645	631,435	17.16	36,797
1978	1,387,227.06	1,436,057	1,441,416	778,147	17.65	44,088
1979	1,865,137.90	1,900,352	1,907,443	1,076,778	18.16	59,294
1980	2,517,367.96	2,523,007	2,532,422	1,495,367	18.68	80,052
1981	3,100,276.31	3,054,640	3,066,038	1,894,404	19.21	98,616
1982	2,844,616.06	2,753,588	2,763,863	1,787,523	19.75	90,507
1983	2,498,731.17	2,374,794	2,383,656	1,614,314	20.30	79,523
1984	2,998,699.98	2,796,228	2,806,662	1,991,258	20.86	95,458
1985	3,536,994.92	3,233,662	3,245,728	2,413,464	21.43	112,621
1986	3,611,533.17	3,234,778	3,246,849	2,531,604	22.01	115,021
1987	3,202,654.43	2,808,087	2,818,565	2,305,682	22.60	102,021
1988	2,781,970.82	2,385,818	2,394,721	2,056,432	23.20	88,639
1989	1,315,031.44	1,102,102	1,106,214	997,836	23.81	41,908
1990	3,358,112.94	2,748,817	2,759,074	2,613,907	24.42	107,040
1991	4,242,890.96	3,387,524	3,400,165	3,388,461	25.05	135,268
1992	4,554,588.05	3,544,563	3,557,790	3,729,551	25.68	145,232
1993	4,206,956.59	3,187,863	3,199,759	3,531,372	26.32	134,171
1994	4,908,951.11	3,616,130	3,629,624	4,224,698	26.98	156,586
1995	4,455,091.77	3,189,133	3,201,033	3,927,114	27.63	142,132
1996	6,514,147.72	4,523,424	4,540,303	5,882,333	28.30	207,856
1997	1,905,311.48	1,282,198	1,286,983	1,761,515	28.97	60,805
1998	2,552,406.14	1,661,310	1,667,509	2,416,341	29.66	81,468
1999	5,019,117.02	3,157,627	3,169,410	4,861,177	30.34	160,223
2000	7,545,656.40	4,578,101	4,595,184	7,477,866	31.04	240,911
2001	4,320,851.94	2,524,760	2,534,181	4,379,182	31.74	137,970
2002	4,214,797.05	2,367,030	2,375,863	4,367,812	32.45	134,601
2003	4,343,863.32	2,339,431	2,348,161	4,602,020	33.17	138,740

KENTUCKY POWER COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -60						
2004	4,327,307.51	2,230,814	2,239,138	4,684,554	33.89	138,228
2005	4,796,570.64	2,360,680	2,369,489	5,305,024	34.62	153,236
2006	5,659,559.15	2,653,201	2,663,101	6,392,194	35.35	180,826
2007	7,131,907.80	3,174,555	3,186,401	8,224,651	36.09	227,893
2008	7,412,007.23	3,123,716	3,135,372	8,723,840	36.83	236,868
2009	9,636,608.42	3,829,974	3,844,265	11,574,308	37.58	307,991
2010	6,069,827.77	2,266,716	2,275,174	7,436,550	38.33	194,014
2011	6,211,650.55	2,168,611	2,176,703	7,761,938	39.09	198,566
2012	6,720,357.11	2,182,772	2,190,917	8,561,654	39.85	214,847
2013	7,134,998.75	2,141,641	2,149,633	9,266,365	40.62	228,123
2014	7,455,548.00	2,051,767	2,059,423	9,869,454	41.40	238,393
2015	8,056,148.89	2,018,549	2,026,081	10,863,757	42.17	257,618
2016	7,698,214.16	1,734,254	1,740,725	10,576,418	42.96	246,192
2017	6,841,368.22	1,370,463	1,375,577	9,570,612	43.74	218,807
2018	9,967,845.10	1,744,772	1,751,283	14,197,269	44.53	318,825
2019	15,566,082.63	2,326,195	2,334,875	22,570,857	45.33	497,923
2020	25,218,490.75	3,123,058	3,134,712	37,214,873	46.13	806,739
2021	21,730,918.63	2,127,892	2,135,832	32,633,638	46.94	695,220
2022	19,968,179.07	1,437,709	1,443,074	30,506,013	47.75	638,869
2023	28,329,951.04	1,305,444	1,310,315	44,017,607	48.56	906,458
2024	16,542,924.50	328,212	329,437	26,139,242	49.38	529,349
2025	1,349,226.91	4,318	4,334	2,154,429	49.90	43,175
	331,435,875.47	121,552,108	122,005,680	408,291,721		10,589,770
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						38.6 3.20

KENTUCKY POWER COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R1.5						
NET SALVAGE PERCENT.. -30						
1954	347.31	409	364	88	3.96	22
1956	8.17	9	8	3	4.44	1
1957	33.05	38	34	9	4.69	2
1958	143.69	165	147	40	4.94	8
1959	363.27	414	369	103	5.21	20
1960	790.12	893	795	232	5.48	42
1961	1,241.27	1,393	1,240	374	5.75	65
1962	2,964.53	3,301	2,940	914	6.03	152
1963	4,072.58	4,498	4,005	1,289	6.32	204
1964	6,209.64	6,802	6,057	2,016	6.61	305
1965	14,057.37	15,272	13,600	4,675	6.90	678
1966	29,579.22	31,861	28,372	10,081	7.20	1,400
1967	43,827.47	46,788	41,665	15,311	7.51	2,039
1968	72,419.43	76,616	68,226	25,919	7.82	3,314
1969	104,110.52	109,113	97,165	38,179	8.14	4,690
1970	137,669.48	142,877	127,232	51,738	8.47	6,108
1971	199,571.50	205,084	182,627	76,816	8.80	8,729
1972	320,793.78	326,277	290,549	126,483	9.14	13,838
1973	290,433.93	292,163	260,171	117,393	9.50	12,357
1974	323,090.34	321,414	286,219	133,798	9.86	13,570
1975	330,645.63	325,143	289,540	140,299	10.23	13,714
1976	377,513.73	366,790	326,626	164,142	10.61	15,470
1977	1,226,858.75	1,176,825	1,047,962	546,954	11.01	49,678
1978	1,065,875.89	1,009,202	898,694	486,945	11.41	42,677
1979	1,344,014.95	1,255,080	1,117,648	629,571	11.83	53,218
1980	1,613,349.92	1,485,137	1,322,513	774,842	12.26	63,201
1981	2,087,982.17	1,893,604	1,686,253	1,028,124	12.70	80,955
1982	1,426,105.16	1,273,469	1,134,023	719,914	13.15	54,746
1983	1,396,889.31	1,227,060	1,092,696	723,260	13.62	53,103
1984	1,381,187.25	1,192,762	1,062,154	733,389	14.10	52,013
1985	1,580,263.52	1,340,705	1,193,897	860,446	14.59	58,975
1986	2,106,384.49	1,754,456	1,562,342	1,175,958	15.09	77,930
1987	2,463,878.29	2,012,567	1,792,189	1,410,853	15.61	90,381
1988	2,169,704.75	1,736,682	1,546,514	1,274,102	16.14	78,941
1989	2,498,480.36	1,958,104	1,743,690	1,504,334	16.68	90,188
1990	2,685,141.10	2,058,665	1,833,240	1,657,443	17.23	96,195
1991	2,664,894.68	1,996,131	1,777,553	1,686,810	17.80	94,765
1992	2,435,557.93	1,781,382	1,586,319	1,579,906	18.37	86,005
1993	2,230,482.31	1,590,648	1,416,471	1,483,156	18.96	78,226
1994	3,390,377.47	2,354,878	2,097,017	2,310,474	19.56	118,122
1995	4,544,015.16	3,070,337	2,734,133	3,173,087	20.17	157,317
1996	2,602,080.31	1,708,266	1,521,210	1,861,494	20.79	89,538



KENTUCKY POWER COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R1.5						
NET SALVAGE PERCENT.. -30						
1997	6,399,824.42	4,076,688	3,630,287	4,689,485	21.42	218,930
1998	2,033,361.00	1,254,966	1,117,546	1,525,823	22.06	69,167
1999	3,327,388.92	1,986,707	1,769,161	2,556,445	22.71	112,569
2000	5,390,439.21	3,108,348	2,767,981	4,239,590	23.37	181,412
2001	3,208,205.11	1,783,460	1,588,170	2,582,497	24.04	107,425
2002	2,998,939.13	1,604,010	1,428,370	2,470,251	24.72	99,929
2003	2,163,211.81	1,110,809	989,175	1,823,000	25.41	71,743
2004	3,982,312.10	1,959,859	1,745,253	3,431,753	26.10	131,485
2005	3,269,587.75	1,537,265	1,368,933	2,881,531	26.81	107,480
2006	6,515,937.07	2,920,365	2,600,583	5,870,135	27.52	213,304
2007	12,520,861.63	5,336,617	4,752,253	11,524,867	28.23	408,249
2008	6,490,978.38	2,619,915	2,333,032	6,105,240	28.96	210,816
2009	12,535,818.71	4,776,523	4,253,490	12,043,074	29.69	405,627
2010	6,710,349.91	2,403,137	2,139,992	6,583,463	30.43	216,348
2011	6,893,692.72	2,308,739	2,055,930	6,905,871	31.18	221,484
2012	14,027,543.01	4,372,217	3,893,456	14,342,350	31.93	449,181
2013	15,820,170.35	4,563,645	4,063,922	16,502,299	32.68	504,966
2014	13,142,611.76	3,478,074	3,097,222	13,988,173	33.45	418,182
2015	15,507,995.56	3,734,511	3,325,579	16,834,815	34.22	491,958
2016	13,661,872.33	2,964,216	2,639,632	15,120,802	34.99	432,146
2017	11,488,088.13	2,215,237	1,972,667	12,961,848	35.77	362,366
2018	15,061,428.74	2,540,682	2,262,475	17,317,382	36.55	473,800
2019	21,075,500.99	3,033,249	2,701,106	24,697,045	37.35	661,233
2020	14,860,647.80	1,775,402	1,580,994	17,737,848	38.14	465,072
2021	20,723,450.09	1,962,884	1,747,947	25,192,538	38.94	646,958
2022	15,945,822.81	1,110,483	988,884	19,740,686	39.75	496,621
2023	20,140,860.72	897,819	799,508	25,383,611	40.56	625,829
2024	17,618,418.29	338,062	301,044	22,602,900	41.38	546,228
2025	8,151,364.79	25,220	22,458	10,574,316	41.90	252,370
	346,840,093.04	107,952,389	96,131,519	354,760,602		11,265,780
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						31.5 3.25

KENTUCKY POWER COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -30						
1969	1,371.41	1,287	1,706	77	18.08	4
1970	16,088.18	14,901	19,750	1,165	18.69	62
1971	18,902.51	17,273	22,894	1,679	19.31	87
1972	37,031.74	33,373	44,232	3,909	19.94	196
1973	25,808.12	22,928	30,389	3,162	20.58	154
1974	38,889.52	34,036	45,111	5,445	21.24	256
1975	28,803.95	24,823	32,900	4,545	21.91	207
1976	1,274.49	1,081	1,433	224	22.59	10
1977	17,385.73	14,507	19,227	3,374	23.28	145
1978	26,692.16	21,898	29,023	5,677	23.98	237
1979	34,265.23	27,624	36,613	7,932	24.69	321
1980	25,979.27	20,570	27,263	6,510	25.41	256
1981	21,913.74	17,031	22,573	5,915	26.14	226
1982	20,575.22	15,687	20,791	5,957	26.88	222
1983	23,870.14	17,840	23,645	7,386	27.63	267
1984	16,437.85	12,036	15,952	5,417	28.39	191
1985	36,789.53	26,371	34,952	12,874	29.16	441
1986	24,846.31	17,427	23,098	9,202	29.93	307
1987	37,527.53	25,729	34,101	14,685	30.72	478
1988	39,724.05	26,607	35,265	16,376	31.51	520
1989	70,874.83	46,338	61,416	30,721	32.31	951
1990	64,909.76	41,386	54,853	29,530	33.12	892
1991	94,891.40	58,966	78,153	45,206	33.93	1,332
1992	118,150.76	71,457	94,709	58,887	34.76	1,694
1993	159,370.40	93,741	124,244	82,938	35.59	2,330
1994	145,570.20	83,179	110,245	78,996	36.43	2,168
1995	155,388.17	86,147	114,179	87,826	37.28	2,356
1996	162,829.52	87,504	115,977	95,701	38.13	2,510
1997	224,122.82	116,588	154,525	136,835	38.99	3,509
1998	330,629.88	166,241	220,335	209,484	39.86	5,255
1999	155,786.34	75,618	100,223	102,299	40.73	2,512
2000	179,734.51	84,081	111,440	122,215	41.61	2,937
2001	98,328.36	44,247	58,645	69,182	42.50	1,628
2002	111,882.98	48,356	64,091	81,357	43.39	1,875
2003	174,341.82	72,213	95,711	130,933	44.29	2,956
2004	144,981.96	57,414	76,096	112,381	45.20	2,486
2005	297,304.53	112,323	148,872	237,624	46.11	5,153
2006	402,902.85	144,802	191,919	331,855	47.03	7,056
2007	178,277.13	60,793	80,575	151,185	47.95	3,153
2008	546,591.48	176,221	233,562	477,007	48.88	9,759
2009	573,583.92	174,253	230,953	514,706	49.81	10,333
2010	270,315.72	77,040	102,108	249,302	50.75	4,912

KENTUCKY POWER COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -30						
2011	260,306.03	69,294	91,842	246,556	51.69	4,770
2012	354,449.34	87,618	116,128	344,656	52.64	6,547
2013	544,499.46	124,256	164,688	543,161	53.59	10,135
2014	427,482.88	89,428	118,527	437,201	54.54	8,016
2015	195,358.25	37,117	49,195	204,771	55.50	3,690
2016	155,806.17	26,611	35,270	167,278	56.46	2,963
2017	159,085.28	24,085	31,922	174,889	57.43	3,045
2018	157,877.02	20,840	27,621	177,619	58.40	3,041
2019	323,776.17	36,459	48,322	372,587	59.37	6,276
2020	228,531.67	21,298	28,228	268,863	60.34	4,456
2021	1,633,600.29	120,243	159,369	1,964,311	61.32	32,034
2022	315,999.08	17,065	22,618	388,181	62.30	6,231
2023	86,091.47	2,961	3,925	107,994	63.28	1,707
2024	164,801.30	2,438	3,231	211,011	64.26	3,284
2025	19,073.84	46	61	24,735	64.88	381
	10,181,684.27	3,051,696	4,044,696	9,191,494		178,920
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						51.4 1.76

KENTUCKY POWER COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -20						
1975	21,730.89	17,633	22,191	3,886	16.19	240
1976	27,736.97	22,187	27,922	5,362	16.67	322
1977	46,230.61	36,437	45,856	9,621	17.16	561
1978	47,094.83	36,564	46,016	10,498	17.65	595
1979	79,446.96	60,710	76,403	18,933	18.16	1,043
1980	70,100.69	52,693	66,314	17,807	18.68	953
1981	57,448.56	42,452	53,426	15,512	19.21	807
1982	48,795.24	35,425	44,582	13,972	19.75	707
1983	53,855.00	38,388	48,311	16,315	20.30	804
1984	51,854.15	36,265	45,639	16,586	20.86	795
1985	73,089.38	50,116	63,071	24,636	21.43	1,150
1986	49,991.46	33,582	42,263	17,727	22.01	805
1987	73,111.48	48,078	60,506	27,228	22.60	1,205
1988	92,567.01	59,539	74,930	36,150	23.20	1,558
1989	125,946.13	79,165	99,629	51,506	23.81	2,163
1990	90,407.26	55,503	69,850	38,639	24.42	1,582
1991	137,993.42	82,630	103,989	61,603	25.05	2,459
1992	156,063.30	91,091	114,638	72,638	25.68	2,829
1993	181,005.30	102,869	129,460	87,746	26.32	3,334
1994	166,565.48	92,024	115,812	84,067	26.98	3,116
1995	183,244.66	98,380	123,811	96,083	27.63	3,477
1996	195,120.12	101,619	127,887	106,257	28.30	3,755
1997	238,621.45	120,437	151,569	134,777	28.97	4,652
1998	526,968.67	257,245	323,741	308,621	29.66	10,405
1999	155,274.88	73,265	92,204	94,126	30.34	3,102
2000	374,194.15	170,273	214,288	234,745	31.04	7,563
2001	191,845.99	84,075	105,808	124,407	31.74	3,920
2002	175,136.96	73,768	92,837	117,327	32.45	3,616
2003	231,060.56	93,330	117,455	159,818	33.17	4,818
2004	612,733.35	236,907	298,146	437,134	33.89	12,899
2005	453,759.44	167,492	210,788	333,723	34.62	9,640
2006	667,912.26	234,838	295,542	505,953	35.35	14,313
2007	680,313.90	227,116	285,824	530,553	36.09	14,701
2008	487,082.85	153,957	193,754	390,745	36.83	10,609
2009	376,508.51	112,230	141,241	310,569	37.58	8,264
2010	322,297.68	90,269	113,603	273,154	38.33	7,126
2011	467,003.19	122,280	153,889	406,515	39.09	10,399
2012	432,252.12	105,297	132,516	386,187	39.85	9,691
2013	864,659.02	194,652	244,968	792,623	40.62	19,513
2014	562,073.11	116,012	146,001	528,487	41.40	12,765
2015	515,916.92	96,951	122,012	497,088	42.17	11,788
2016	340,205.10	57,481	72,340	335,906	42.96	7,819

KENTUCKY POWER COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -20						
2017	387,444.40	58,210	73,257	391,676	43.74	8,955
2018	268,811.04	35,290	44,412	278,161	44.53	6,247
2019	181,679.76	20,363	25,627	192,389	45.33	4,244
2020	402,644.06	37,398	47,065	436,108	46.13	9,454
2021	453,993.18	33,341	41,959	502,833	46.94	10,712
2022	463,706.96	25,040	31,513	524,935	47.75	10,993
2023	266,137.15	9,198	11,576	307,789	48.56	6,338
2024	265,526.97	3,951	4,972	313,660	49.38	6,352
2025	60,145.16	144	181	71,993	49.90	1,443
	13,455,307.69	4,284,160	5,391,594	10,754,775		286,601
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						37.5 2.13

KENTUCKY POWER COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. -20						
1973	91,070.95	97,857	73,230	36,055	3.66	9,851
1974	247,550.56	263,451	197,151	99,910	3.96	25,230
1975	76,195.79	80,332	60,116	31,319	4.25	7,369
1976	187,435.70	195,683	146,437	78,486	4.55	17,250
1977	333,457.38	344,700	257,952	142,197	4.85	29,319
1978	488,399.69	499,674	373,926	212,154	5.16	41,115
1979	649,715.57	657,806	492,262	287,397	5.47	52,541
1980	662,937.87	663,699	496,672	298,853	5.80	51,526
1981	794,040.74	785,691	587,963	364,886	6.14	59,428
1982	548,202.73	535,859	401,004	256,839	6.49	39,575
1983	604,739.43	583,663	436,778	288,909	6.85	42,176
1984	887,797.54	845,585	632,784	432,573	7.22	59,913
1985	1,203,285.00	1,129,986	845,613	598,329	7.61	78,624
1986	1,504,053.81	1,391,298	1,041,163	763,702	8.02	95,225
1987	1,437,113.97	1,308,682	979,338	745,199	8.44	88,294
1988	1,464,490.15	1,311,521	981,462	775,926	8.88	87,379
1989	2,082,931.41	1,833,221	1,371,871	1,127,647	9.33	120,862
1990	1,697,926.29	1,467,008	1,097,819	939,693	9.80	95,887
1991	1,802,710.22	1,527,256	1,142,905	1,020,347	10.29	99,159
1992	2,028,765.09	1,683,299	1,259,678	1,174,840	10.80	108,781
1993	1,952,956.27	1,585,574	1,186,547	1,157,001	11.32	102,209
1994	2,152,365.79	1,707,618	1,277,877	1,304,962	11.86	110,031
1995	2,484,174.89	1,924,033	1,439,829	1,541,181	12.41	124,189
1996	2,448,149.49	1,847,452	1,382,520	1,555,259	12.99	119,727
1997	2,415,932.71	1,775,102	1,328,378	1,570,741	13.57	115,751
1998	7,784,641.58	5,556,926	4,158,465	5,183,105	14.18	365,522
1999	2,981,285.99	2,064,743	1,545,128	2,032,415	14.80	137,325
2000	3,144,395.47	2,109,789	1,578,837	2,194,438	15.43	142,219
2001	2,118,520.07	1,374,250	1,028,405	1,513,819	16.08	94,143
2002	1,879,432.24	1,175,991	880,040	1,375,279	16.75	82,106
2003	2,025,382.45	1,220,090	913,041	1,517,418	17.43	87,058
2004	2,284,008.80	1,321,866	989,204	1,751,607	18.12	96,667
2005	2,488,984.24	1,380,759	1,033,276	1,953,505	18.82	103,799
2006	4,054,540.67	2,149,117	1,608,268	3,257,181	19.54	166,693
2007	6,416,304.57	3,240,439	2,424,947	5,274,618	20.27	260,218
2008	6,090,082.04	2,919,074	2,184,457	5,123,641	21.02	243,751
2009	3,858,413.37	1,750,176	1,309,725	3,320,371	21.77	152,520
2010	4,064,075.52	1,736,173	1,299,246	3,577,645	22.54	158,724
2011	4,959,266.35	1,985,948	1,486,162	4,464,958	23.32	191,465
2012	6,782,770.73	2,532,470	1,895,146	6,244,179	24.11	258,987
2013	5,767,055.90	1,995,101	1,493,012	5,427,455	24.91	217,883
2014	6,020,117.37	1,917,504	1,434,943	5,789,198	25.71	225,173

KENTUCKY POWER COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. -20						
2015	5,589,734.43	1,623,259	1,214,748	5,492,933	26.53	207,046
2016	4,755,474.18	1,245,687	932,196	4,774,373	27.36	174,502
2017	5,544,978.34	1,292,801	967,453	5,686,521	28.20	201,650
2018	5,684,613.53	1,159,661	867,820	5,953,716	29.05	204,947
2019	6,926,659.23	1,208,813	904,602	7,407,389	29.91	247,656
2020	7,699,365.60	1,113,975	833,631	8,405,608	30.78	273,087
2021	7,727,783.17	887,551	664,189	8,609,151	31.65	272,011
2022	7,404,556.70	627,047	469,244	8,416,224	32.53	258,722
2023	8,558,216.55	463,581	346,916	9,922,944	33.42	296,916
2024	7,034,550.74	164,018	122,741	8,318,720	34.32	242,387
2025	3,308,795.67	12,468	9,330	3,961,225	34.89	113,535
	173,200,404.54	72,275,327	54,086,447	153,754,038		7,258,123
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.2 4.19						

KENTUCKY POWER COMPANY

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-S2.5						
NET SALVAGE PERCENT.. -60						
1967	2,790.22	4,032	2,976	1,488	3.78	394
1968	3,401.08	4,886	3,606	1,836	3.98	461
1969	4,820.04	6,883	5,080	2,632	4.19	628
1970	7,578.40	10,761	7,942	4,183	4.39	953
1971	13,505.48	19,054	14,062	7,547	4.61	1,637
1972	27,117.47	38,014	28,054	15,334	4.83	3,175
1973	34,955.41	48,686	35,930	19,999	5.05	3,960
1974	28,854.38	39,917	29,459	16,708	5.28	3,164
1975	44,883.19	61,649	45,497	26,316	5.52	4,767
1976	56,940.41	77,626	57,288	33,817	5.77	5,861
1977	82,116.80	111,072	81,971	49,416	6.03	8,195
1978	111,236.37	149,228	110,130	67,848	6.30	10,770
1979	116,686.72	155,199	114,537	72,162	6.58	10,967
1980	137,628.61	181,417	133,885	86,321	6.87	12,565
1981	144,570.55	188,786	139,324	91,989	7.17	12,830
1982	155,527.88	201,119	148,425	100,420	7.48	13,425
1983	224,263.48	286,964	211,779	147,043	7.81	18,828
1984	245,407.91	310,498	229,147	163,506	8.16	20,038
1985	242,085.04	302,719	223,406	163,930	8.52	19,241
1986	273,727.10	338,130	249,539	188,424	8.89	21,195
1987	380,712.81	464,196	342,576	266,564	9.28	28,725
1988	386,007.88	464,161	342,550	275,063	9.69	28,386
1989	557,936.58	661,052	487,855	404,844	10.12	40,004
1990	486,805.46	567,787	419,026	359,863	10.57	34,046
1991	686,963.18	787,996	581,540	517,601	11.04	46,884
1992	700,705.36	789,387	582,566	538,563	11.54	46,669
1993	1,038,112.01	1,147,786	847,064	813,915	12.05	67,545
1994	805,377.98	872,617	643,990	644,615	12.59	51,201
1995	774,082.44	820,924	605,840	632,692	13.15	48,113
1996	585,094.91	606,336	447,475	488,677	13.74	35,566
1997	1,929,548.29	1,951,314	1,440,066	1,647,211	14.35	114,788
1998	627,611.50	618,212	456,239	547,939	14.99	36,554
1999	1,447,942.34	1,387,059	1,023,647	1,293,061	15.65	82,624
2000	3,061,026.66	2,845,677	2,100,105	2,797,538	16.34	171,208
2001	1,374,950.15	1,238,159	913,759	1,286,161	17.05	75,435
2002	1,226,021.31	1,066,835	787,322	1,174,312	17.79	66,010
2003	1,951,086.19	1,636,103	1,207,441	1,914,297	18.56	103,141
2004	1,928,233.62	1,554,465	1,147,192	1,937,982	19.35	100,154
2005	2,122,542.97	1,640,573	1,210,740	2,185,329	20.16	108,399
2006	2,463,158.61	1,818,954	1,342,385	2,598,669	21.00	123,746
2007	2,407,378.89	1,692,830	1,249,306	2,602,500	21.86	119,053
2008	2,718,778.96	1,814,752	1,339,284	3,010,762	22.73	132,458



KENTUCKY POWER COMPANY

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 39-S2.5						
NET SALVAGE PERCENT.. -60						
2009	3,893,016.30	2,454,780	1,811,623	4,417,203	23.63	186,932
2010	2,887,659.99	1,713,052	1,264,229	3,356,027	24.54	136,757
2011	2,792,017.15	1,549,771	1,143,728	3,323,499	25.47	130,487
2012	3,610,542.23	1,864,888	1,376,284	4,400,584	26.41	166,626
2013	4,399,609.50	2,099,212	1,549,215	5,490,160	27.37	200,590
2014	2,334,167.59	1,021,768	754,063	2,980,605	28.33	105,210
2015	2,324,465.80	925,026	682,668	3,036,477	29.30	103,634
2016	2,217,276.44	793,217	585,393	2,962,249	30.28	97,829
2017	1,998,407.85	633,767	467,719	2,729,734	31.27	87,296
2018	1,987,875.82	549,672	405,657	2,774,944	32.26	86,018
2019	3,125,819.34	736,093	543,235	4,458,076	33.26	134,037
2020	3,375,817.31	657,825	485,474	4,915,834	34.25	143,528
2021	3,705,441.57	570,045	420,692	5,508,015	35.25	156,256
2022	2,802,612.96	316,180	233,341	4,250,840	36.25	117,265
2023	3,176,378.19	228,039	168,292	4,913,913	37.25	131,917
2024	3,034,769.49	93,374	68,910	4,786,721	38.25	125,143
2025	413,714.07	2,039	1,505	660,438	38.88	16,987
	79,697,766.24	45,192,563	33,352,033	94,164,393		3,960,275
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						23.8 4.97

KENTUCKY POWER COMPANY

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 26-R0.5						
PROBABLE RETIREMENT YEAR.. 12-2029						
NET SALVAGE PERCENT.. -10						
1980	2,127.41	2,073	1,334	1,006	2.97	339
1981	569.20	551	355	271	3.13	87
1982	1,144.69	1,100	708	551	3.27	169
1983	1,388.52	1,328	855	672	3.38	199
1984	2,309.42	2,198	1,415	1,125	3.47	324
1985	14,482.89	13,722	8,833	7,098	3.56	1,994
1986	4,899.08	4,624	2,977	2,412	3.63	664
1987	8,001.02	7,521	4,841	3,960	3.70	1,070
1988	12,214.44	11,439	7,363	6,073	3.76	1,615
1989	13,336.84	12,441	8,008	6,663	3.82	1,744
1990	39,552.94	36,762	23,664	19,844	3.87	5,128
1991	12,387.56	11,468	7,382	6,244	3.92	1,593
1992	20,695.95	19,081	12,283	10,483	3.97	2,641
1993	29,145.20	26,765	17,229	14,831	4.01	3,699
1994	56,471.11	51,614	33,225	28,893	4.06	7,117
1995	31,700.24	28,858	18,576	16,294	4.09	3,984
1996	32,629.95	29,558	19,027	16,866	4.13	4,084
1997	83,441.17	75,220	48,420	43,365	4.16	10,424
1998	144,952.63	129,934	83,640	75,808	4.20	18,050
1999	111,262.17	99,163	63,833	58,555	4.23	13,843
2000	16,766.11	14,860	9,566	8,877	4.25	2,089
2001	253,061.68	222,797	143,417	134,951	4.28	31,531
2002	618,001.89	540,082	347,658	332,144	4.31	77,064
2003	66,065.53	57,307	36,889	35,783	4.33	8,264
2004	332,335.41	285,897	184,036	181,533	4.35	41,732
2005	622,918.07	531,099	341,876	343,334	4.37	78,566
2006	8,162,963.00	6,889,157	4,434,644	4,544,615	4.39	1,035,220
2007	1,298,259.53	1,083,560	697,502	730,583	4.41	165,665
2008	2,069,341.99	1,705,591	1,097,912	1,178,364	4.43	265,996
2009	760,845.05	618,859	398,368	438,562	4.44	98,775
2010	690,183.14	552,608	355,721	403,480	4.46	90,466
2011	633,301.78	498,545	320,920	375,712	4.47	84,052
2012	1,764,062.18	1,362,073	876,785	1,063,683	4.48	237,429
2013	653,818.03	493,695	317,798	401,402	4.49	89,399
2014	775,344.29	569,842	366,815	486,064	4.51	107,775
2015	716,962.57	511,642	329,351	459,308	4.51	101,842
2016	1,077,103.74	741,125	477,072	707,742	4.52	156,580
2017	997,906.03	656,862	422,831	674,866	4.53	148,977
2018	667,973.19	416,159	267,887	466,884	4.54	102,838
2019	624,112.23	362,828	233,558	452,965	4.55	99,553
2020	280,598.10	149,248	96,073	212,585	4.55	46,722

KENTUCKY POWER COMPANY

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 26-R0.5						
PROBABLE RETIREMENT YEAR.. 12-2029						
NET SALVAGE PERCENT.. -10						
2021	513,854.90	241,030	155,154	410,086	4.56	89,931
2022	416,138.31	161,866	104,196	353,556	4.57	77,365
2023	528,502.50	151,454	97,493	483,860	4.57	105,877
2024	359,162.09	51,728	33,298	361,780	4.58	78,991
2025	148,797.67	4,179	2,690	160,987	4.58	35,150
	25,671,091.44	19,439,513	12,513,478	15,724,723		3,536,617
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						4.4 13.78

KENTUCKY POWER COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-L0						
NET SALVAGE PERCENT.. -20						
1983	297.20	318	281	76	1.31	58
1984	887.68	937	829	236	1.44	164
1985	1,282.98	1,338	1,184	356	1.57	227
1986	2,976.38	3,066	2,713	859	1.70	505
1987	4,572.20	4,650	4,115	1,372	1.83	750
1988	6,476.03	6,495	5,748	2,023	1.97	1,027
1989	10,227.85	10,115	8,951	3,322	2.11	1,574
1990	9,327.91	9,095	8,049	3,144	2.25	1,397
1991	14,007.72	13,461	11,913	4,896	2.39	2,049
1992	16,479.45	15,589	13,796	5,979	2.54	2,354
1993	31,453.99	29,252	25,887	11,858	2.70	4,392
1994	26,899.21	24,613	21,782	10,497	2.85	3,683
1995	14,627.55	13,150	11,637	5,916	3.01	1,965
1996	16,118.40	14,216	12,581	6,761	3.18	2,126
1997	55,532.03	48,035	42,509	24,129	3.35	7,203
1998	30,147.71	25,565	22,624	13,553	3.52	3,850
1999	43,937.15	36,468	32,273	20,452	3.70	5,528
2000	85,708.06	69,509	61,513	41,337	3.89	10,626
2001	395,591.33	313,308	277,267	197,443	4.08	48,393
2002	111,464.45	86,050	76,151	57,606	4.28	13,459
2003	143,618.39	108,002	95,578	76,764	4.48	17,135
2004	176,205.17	128,807	113,990	97,456	4.69	20,780
2005	192,403.51	136,413	120,721	110,163	4.91	22,436
2006	219,524.06	150,813	133,464	129,965	5.13	25,334
2007	235,555.05	156,173	138,208	144,458	5.37	26,901
2008	298,692.02	190,864	168,908	189,522	5.61	33,783
2009	342,560.20	210,333	186,137	224,935	5.86	38,385
2010	316,126.68	185,882	164,499	214,853	6.12	35,107
2011	416,588.72	233,706	206,821	293,085	6.39	45,866
2012	480,677.19	256,203	226,731	350,082	6.67	52,486
2013	770,814.05	387,723	343,121	581,856	6.97	83,480
2014	428,192.17	202,537	179,238	334,593	7.27	46,024
2015	580,955.93	256,202	226,730	470,417	7.59	61,979
2016	692,433.84	282,513	250,014	580,907	7.92	73,347
2017	655,888.00	244,644	216,501	570,565	8.27	68,992
2018	680,933.47	229,472	203,075	614,045	8.63	71,152
2019	916,406.36	274,922	243,296	856,392	9.00	95,155
2020	1,314,778.27	341,848	302,523	1,275,211	9.40	135,661
2021	2,229,446.91	486,028	430,118	2,245,218	9.82	228,637
2022	2,446,937.25	418,426	370,292	2,566,033	10.29	249,372

KENTUCKY POWER COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-L0						
NET SALVAGE PERCENT.. -20						
2023	2,913,310.85	346,696	306,813	3,189,160	10.81	295,019
2024	2,867,765.42	163,463	144,659	3,296,660	11.43	288,422
2025	517,658.16	5,696	5,041	616,149	11.89	51,821
	20,715,486.95	6,122,596	5,418,281	19,440,303		2,178,604
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.9						10.52

## KENTUCKY POWER COMPANY

## ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 32-S0						
NET SALVAGE PERCENT.. -30						
1962	280.00	359	213	151	0.47	151
1963	1,208.38	1,530	908	663	0.83	663
1964	235.00	294	175	130	1.19	109
1965	2,112.22	2,612	1,550	1,196	1.56	767
1966	1,985.72	2,426	1,440	1,141	1.93	591
1967	4,384.74	5,289	3,140	2,560	2.31	1,108
1968	3,010.71	3,586	2,129	1,785	2.68	666
1969	3,385.80	3,981	2,363	2,039	3.06	666
1970	6,674.88	7,747	4,599	4,078	3.43	1,189
1971	3,445.01	3,945	2,342	2,137	3.81	561
1972	3,051.84	3,447	2,046	1,921	4.20	457
1973	6,482.30	7,221	4,286	4,141	4.58	904
1974	5,831.32	6,403	3,801	3,780	4.97	761
1975	4,932.67	5,338	3,169	3,243	5.36	605
1976	3,697.84	3,943	2,341	2,466	5.75	429
1977	4,016.93	4,220	2,505	2,717	6.14	443
1978	7,967.29	8,241	4,892	5,465	6.54	836
1979	5,294.99	5,393	3,201	3,682	6.93	531
1980	15,068.94	15,102	8,965	10,625	7.33	1,450
1981	33,654.33	33,168	19,689	24,062	7.74	3,109
1982	42,419.12	41,117	24,407	30,738	8.14	3,776
1983	21,110.32	20,111	11,938	15,505	8.55	1,813
1984	12,172.74	11,394	6,763	9,062	8.96	1,011
1985	37,638.01	34,587	20,531	28,398	9.38	3,028
1986	68,400.53	61,689	36,619	52,302	9.80	5,337
1987	71,239.74	63,033	37,416	55,196	10.22	5,401
1988	82,075.72	71,188	42,257	64,441	10.65	6,051
1989	141,018.39	119,848	71,142	112,182	11.08	10,125
1990	100,624.20	83,760	49,720	81,091	11.51	7,045
1991	27,491.20	22,392	13,292	22,447	11.95	1,878
1992	8,615.44	6,864	4,074	7,126	12.39	575
1993	93,922.72	73,145	43,419	78,681	12.83	6,133
1994	49,230.69	37,420	22,213	41,787	13.29	3,144
1995	31,825.82	23,609	14,014	27,360	13.74	1,991
1996	24,214.04	17,510	10,394	21,084	14.20	1,485
1997	20,782.92	14,632	8,686	18,332	14.67	1,250
1998	24,842.76	17,016	10,101	22,195	15.14	1,466
1999	31,973.52	21,277	12,630	28,936	15.62	1,852
2000	111,950.24	72,314	42,926	102,609	16.10	6,373
2001	46,585.94	29,164	17,312	43,250	16.59	2,607
2002	5,317.06	3,221	1,912	5,000	17.09	293
2003	84,242.05	49,316	29,274	80,241	17.59	4,562

KENTUCKY POWER COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 32-S0						
NET SALVAGE PERCENT.. -30						
2004	54,992.83	31,031	18,420	53,071	18.11	2,930
2005	40,846.37	22,186	13,170	39,930	18.63	2,143
2006	40,876.79	21,322	12,657	40,483	19.16	2,113
2007	88,261.53	44,139	26,201	88,539	19.69	4,497
2008	89,976.62	42,986	25,516	91,454	20.24	4,518
2009	61,725.09	28,085	16,671	63,572	20.80	3,056
2010	73,408.32	31,701	18,818	76,613	21.37	3,585
2011	71,801.35	29,315	17,401	75,941	21.95	3,460
2012	156,261.04	59,989	35,610	167,529	22.55	7,429
2013	212,938.26	76,471	45,393	231,427	23.16	9,993
2014	174,408.04	58,243	34,573	192,157	23.78	8,081
2015	161,443.96	49,716	29,511	180,366	24.42	7,386
2016	342,170.75	96,193	57,100	387,722	25.08	15,459
2017	181,607.92	46,038	27,328	208,762	25.76	8,104
2018	180,252.46	40,567	24,081	210,247	26.46	7,946
2019	263,198.97	51,536	30,592	311,567	27.18	11,463
2020	300,963.99	49,763	29,539	361,714	27.93	12,951
2021	241,224.76	32,240	19,138	294,454	28.71	10,256
2022	385,101.46	38,799	23,031	477,601	29.52	16,179
2023	564,183.65	37,127	22,039	711,400	30.38	23,417
2024	620,166.87	18,140	10,768	795,449	31.28	25,430
2025	154,129.53	751	446	199,922	31.88	6,271
	5,714,354.64	1,925,190	1,142,797	6,285,864		289,859
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						21.7 5.07

KENTUCKY POWER COMPANY

ACCOUNT 389.10 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R4						
NET SALVAGE PERCENT.. 0						
1979	3,899.00	2,280	1,715	2,184	31.14	70
1984	678.00	357	269	409	35.48	12
1985	1,227.00	632	475	752	36.37	21
1986	22,442.00	11,290	8,492	13,950	37.27	374
2003	7,500.00	2,161	1,625	5,875	53.39	110
2022	2.12			2	72.25	
	35,748.12	16,720	12,576	23,172		587
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.5 1.64						



KENTUCKY POWER COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2						
NET SALVAGE PERCENT.. -10						
1938	43,738.00	46,591	48,112			
1939	342.00	362	376			
1940	430.00	453	473			
1941	117.00	122	129			
1942	1,884.00	1,961	2,072			
1944	322.00	331	354			
1945	434.00	444	477			
1948	536.00	538	590			
1949	1,116.00	1,112	1,228			
1950	304.00	301	334			
1952	97.00	95	107			
1953	505.00	490	556			
1957	147.00	139	162			
1958	525.00	492	578			
1959	1,584.00	1,474	1,742			
1960	15,161.00	14,002	16,677			
1961	448.00	411	493			
1962	793.00	721	872			
1963	481.00	434	527	2	9.03	
1966	1,664.00	1,460	1,773	57	10.11	6
1967	6,231.00	5,416	6,578	276	10.49	26
1968	24,994.67	21,506	26,120	1,374	10.89	126
1969	12,870.00	10,960	13,311	846	11.29	75
1970	2,206.00	1,858	2,257	170	11.71	15
1973	4,096.00	3,332	4,047	459	13.02	35
1974	14,153.00	11,371	13,810	1,758	13.48	130
1975	12,975.00	10,290	12,497	1,776	13.95	127
1976	6,155.00	4,815	5,848	922	14.44	64
1977	1,414.00	1,091	1,325	230	14.93	15
1978	16,821.00	12,789	15,533	2,970	15.44	192
1979	15,014.00	11,244	13,656	2,859	15.96	179
1980	6,033.15	4,448	5,402	1,234	16.49	75
1981	3,513,424.23	2,547,654	3,094,182	770,585	17.04	45,222
1982	7,057.00	5,032	6,111	1,652	17.59	94
1983	12,063.00	8,450	10,263	3,006	18.16	166
1985	2,504.00	1,690	2,053	701	19.33	36
1986	12,571.00	8,316	10,100	3,728	19.93	187
1987	11,487.75	7,445	9,042	3,595	20.54	175
1988	2,929.00	1,858	2,257	965	21.16	46
1989	21,105.00	13,094	15,903	7,312	21.80	335
1990	10,909,829.51	6,614,848	8,033,880	3,966,932	22.44	176,780
1991	283,548.67	167,866	203,877	108,027	23.09	4,679

KENTUCKY POWER COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2						
NET SALVAGE PERCENT.. -10						
1992	159,013.00	91,795	111,487	63,427	23.76	2,669
1993	19,257.00	10,833	13,157	8,026	24.43	329
1994	29,461.00	16,126	19,585	12,822	25.12	510
1995	443,252.67	235,890	286,494	201,084	25.81	7,791
1996	844,154.96	436,242	529,826	398,744	26.51	15,041
1997	119,937.12	60,108	73,002	58,929	27.22	2,165
1998	74,053.43	35,940	43,650	37,809	27.94	1,353
2000	266,510.61	120,724	146,622	146,540	29.41	4,983
2001	11,474.97	5,009	6,084	6,538	30.16	217
2002	4,456.24	1,872	2,274	2,628	30.91	85
2004	51,904.08	20,040	24,339	32,755	32.45	1,009
2005	219,239.82	80,886	98,238	142,926	33.23	4,301
2006	441,138.90	155,184	188,474	296,779	34.01	8,726
2007	17,712.90	5,919	7,189	12,295	34.81	353
2008	139,356.61	44,118	53,582	99,710	35.61	2,800
2009	39,209.23	11,714	14,227	28,903	36.42	794
2011	1,141,205.35	300,023	364,384	890,942	38.05	23,415
2012	299,166.58	73,188	88,888	240,195	38.88	6,178
2013	448,133.96	101,350	123,092	369,855	39.72	9,312
2014	442,825.43	91,966	111,695	375,413	40.56	9,256
2015	220,140.68	41,602	50,527	191,628	41.41	4,628
2016	492,223.17	83,707	101,664	439,781	42.27	10,404
2017	533,058.29	80,566	97,849	488,515	43.13	11,327
2018	1,609,494.09	212,453	258,029	1,512,414	44.00	34,373
2019	1,219,245.68	137,604	167,123	1,174,047	44.87	26,166
2020	1,990,211.41	186,085	226,004	1,963,229	45.75	42,912
2021	799,209.72	59,078	71,752	807,379	46.64	17,311
2022	212,857.32	11,567	14,048	220,095	47.53	4,631
2023	148,859.28	5,174	6,284	157,461	48.42	3,252
2024	1,331,434.86	19,918	24,191	1,440,387	49.32	29,205
	28,738,308.34	12,283,987	14,909,444	16,702,695		514,281
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						32.5 1.79

KENTUCKY POWER COMPANY

ACCOUNT 391.00 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE NET SALVAGE PERCENT.. 0						
1994	6,656.00	6,656	6,656			
1998	54,995.00	54,995	54,995			
1999	127,468.00	127,468	127,468			
2000	4,468.27	4,468	4,468			
2001	108,531.78	108,532	108,532			
2002	379,083.62	379,084	379,084			
2004	270,441.21	270,441	270,441			
2005	6,455.04	6,374	120-	6,575	0.25	6,575
2007	13,668.72	12,131	229-	13,898	2.25	6,177
2008	3,650.88	3,058	58-	3,709	3.25	1,141
2010	126,219.47	93,087	1,755-	127,974	5.25	24,376
2013	396,868.44	233,160	4,395-	401,263	8.25	48,638
2016	119,450.14	52,259	985-	120,435	11.25	10,705
2017	221,869.81	85,975	1,620-	223,490	12.25	18,244
2019	408,292.28	117,384	2,212-	410,504	14.25	28,807
2020	92,858.50	22,054	416-	93,274	15.25	6,116
2021	47,212.59	8,852	167-	47,380	16.25	2,916
2022	78,611.29	10,809	204-	78,815	17.25	4,569
2024	51,320.16	1,925	36-	51,356	19.25	2,668
	2,518,121.20	1,598,712	939,447	1,578,674		160,932
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.8						6.39

KENTUCKY POWER COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	3,835.70	3,836	3,836			
2011	10,931.90	10,021	7,009	3,923	1.25	3,138
2022	20,941,134.29	3,839,138	2,685,042	18,256,092	12.25	1,490,293
2023	2,629,808.31	306,820	214,586	2,415,222	13.25	182,281
2024	482,795.45	24,140	16,883	465,912	14.25	32,696
	24,068,505.65	4,183,955	2,927,356	21,141,150		1,708,408
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						12.4 7.10

KENTUCKY POWER COMPANY

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE NET SALVAGE PERCENT.. 0						
1995	25,233.00	25,233	25,233			
2004	39,480.64	32,769	25,327	14,154	4.25	3,330
2006	9,819.85	7,365	5,692	4,128	6.25	660
2008	43,145.39	28,907	22,342	20,803	8.25	2,522
2010	4,830.93	2,850	2,203	2,628	10.25	256
2011	5,854.57	3,220	2,489	3,366	11.25	299
2012	4,653.00	2,373	1,834	2,819	12.25	230
2015	6,255.50	2,440	1,886	4,370	15.25	287
2016	19,920.39	6,972	5,388	14,532	16.25	894
2017	38,814.89	12,033	9,300	29,515	17.25	1,711
2018	32,824.62	8,863	6,850	25,975	18.25	1,423
2019	19,395.85	4,461	3,448	15,948	19.25	828
2020	16,532.20	3,141	2,427	14,105	20.25	697
2021	2,897.82	435	336	2,562	21.25	121
2022	7,267.94	799	618	6,650	22.25	299
2023	132,171.07	9,252	7,150	125,021	23.25	5,377
2024	21,993.40	660	510	21,483	24.25	886
2025	33,327.30	160	124	33,203	24.88	1,335
	464,418.36	151,933	123,157	341,261		21,155
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.1						4.56

KENTUCKY POWER COMPANY

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	26,579.00	26,579	26,579			
1997	113,910.00	113,910	113,910			
1998	135,419.00	135,419	135,419			
1999	242,440.77	242,441	242,441			
2000	209,915.54	207,816	182,321	27,595	0.25	27,595
2001	154,805.23	147,065	129,023	25,782	1.25	20,626
2002	8,900.52	8,099	7,105	1,796	2.25	798
2003	108,886.81	94,732	83,110	25,777	3.25	7,931
2004	401,347.62	333,119	292,251	109,097	4.25	25,670
2005	139,568.65	110,259	96,732	42,837	5.25	8,159
2006	30,324.75	22,744	19,954	10,371	6.25	1,659
2007	142,821.02	101,403	88,963	53,858	7.25	7,429
2008	766,794.71	513,752	450,723	316,072	8.25	38,312
2009	43,589.39	27,461	24,092	19,497	9.25	2,108
2010	42,142.45	24,864	21,814	20,328	10.25	1,983
2011	332,560.59	182,908	160,468	172,093	11.25	15,297
2012	388,408.19	198,088	173,786	214,622	12.25	17,520
2013	166,557.56	78,282	68,678	97,880	13.25	7,387
2014	207,647.94	89,289	78,335	129,313	14.25	9,075
2015	246,262.03	96,042	84,259	162,003	15.25	10,623
2016	173,933.41	60,877	53,408	120,525	16.25	7,417
2017	571,785.06	177,253	155,507	416,278	17.25	24,132
2018	608,998.22	164,430	144,257	464,741	18.25	25,465
2019	461,494.24	106,144	93,122	368,372	19.25	19,136
2020	579,068.33	110,023	96,525	482,543	20.25	23,829
2021	207,876.92	31,182	27,356	180,521	21.25	8,495
2022	486,811.42	53,549	46,980	439,831	22.25	19,768
2023	837,067.27	58,595	51,406	785,661	23.25	33,792
2024	291,801.38	8,754	7,680	284,121	24.25	11,716
2025	219,554.37	1,054	925	218,629	24.88	8,787
	8,347,272.39	3,526,133	3,157,129	5,190,143		384,709

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.5 4.61

KENTUCKY POWER COMPANY

ACCOUNT 395.00 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE NET SALVAGE PERCENT.. 0						
1996	28,363.00	28,363	28,363			
1998	9,244.00	9,244	9,244			
1999	3,800.00	3,800	3,800			
2002	7,357.47	7,357	7,357			
2004	11,433.43	11,433	11,433			
2005	1,833.80	1,811	1,399	435	0.25	435
2014	67,145.62	36,091	27,876	39,270	9.25	4,245
2016	52,543.10	22,988	17,755	34,788	11.25	3,092
2020	22,282.97	5,292	4,088	18,195	15.25	1,193
2022	6,406.67	881	680	5,727	17.25	332
2023	46,410.00	4,061	3,137	43,273	18.25	2,371
	256,820.06	131,321	115,132	141,688		11,668
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.1 4.54						

KENTUCKY POWER COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 17-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	5,931.29	5,931	5,931			
2022	1,636,494.55	264,719	230,663	1,405,832	14.25	98,655
2023	578,818.85	59,584	51,919	526,900	15.25	34,551
	2,221,244.69	330,234	288,513	1,932,732		133,206
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						14.5 6.00



KENTUCKY POWER COMPANY

ACCOUNT 397.10 COMMUNICATION EQUIPMENT - COMPUTER HARDWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	8,490.94	8,491	8,491			
2005	19,913.21	19,913	19,913			
2007	149,601.47	149,601	149,601			
2013	6,820.76	6,821	6,821			
2016	21,454.06	21,454	21,454			
2018	5,169.72	5,170	5,170			
2019	6,544.25	6,544	6,544			
2020	80,908.35	76,863	7,842-	88,750	0.25	88,750
2022	490,395.15	269,717	27,519-	517,914	2.25	230,184
2023	211,800.40	74,130	7,564-	219,364	3.25	67,497
2024	356,398.43	53,460	5,454-	361,852	4.25	85,142
2025	21,033.33	505	52-	21,085	4.88	4,321
	1,378,530.07	692,669	169,563	1,208,967		475,894
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5						34.52

KENTUCKY POWER COMPANY

ACCOUNT 397.21 COMMUNICATION EQUIPMENT - COMPUTER SOFTWARE - 5 YEAR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	10,079,383.56	9,575,414	9,625,437	453,947	0.25	453,947
2021	10,743,439.63	8,057,580	8,099,673	2,643,767	1.25	2,115,014
2022	10,152,450.81	5,583,848	5,613,018	4,539,433	2.25	2,017,526
2023	6,579,576.82	2,302,852	2,314,882	4,264,695	3.25	1,312,214
2024	5,092,978.59	763,947	767,938	4,325,041	4.25	1,017,657
2025	1,193,965.76	28,655	28,805	1,165,161	4.88	238,762
	43,841,795.17	26,312,296	26,449,753	17,392,042		7,155,120
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.4						16.32

KENTUCKY POWER COMPANY

ACCOUNT 397.21 COMMUNICATION EQUIPMENT - COMPUTER SOFTWARE - 10 YEAR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	4,553,052.70	3,528,616	3,528,616	1,024,436	2.25	455,305
	4,553,052.70	3,528,616	3,528,616	1,024,436		455,305
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.2						10.00

KENTUCKY POWER COMPANY

ACCOUNT 397.21 COMMUNICATION EQUIPMENT - COMPUTER SOFTWARE - 11 YEAR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 11-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	471,934.55	75,080	53,427	418,508	9.25	45,244
	471,934.55	75,080	53,427	418,508		45,244
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.3						9.59

KENTUCKY POWER COMPANY

ACCOUNT 397.21 COMMUNICATION EQUIPMENT - COMPUTER SOFTWARE - 15 YEAR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	7,038,488.25	2,698,064	2,464,338	4,574,151	9.25	494,503
	7,038,488.25	2,698,064	2,464,338	4,574,151		494,503
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.2						7.03

KENTUCKY POWER COMPANY

ACCOUNT 397.30 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE NET SALVAGE PERCENT.. 0						
2003	370,360.93	370,361	370,361			
2004	505,619.13	505,619	505,619			
2005	373,813.79	373,814	373,814			
2006	818,515.02	818,515	818,515			
2007	187,516.91	187,517	187,517			
2008	1,334,400.70	1,334,401	1,334,401			
2009	101,882.28	101,882	101,882			
2010	202,024.14	198,656	117,635	84,389	0.25	84,389
2011	177,763.80	162,951	96,492	81,272	1.25	65,018
2012	102,608.15	87,217	51,646	50,962	2.25	22,650
2013	215,944.07	169,155	100,166	115,778	3.25	35,624
2014	577,307.88	413,739	244,997	332,311	4.25	78,191
2015	1,161,401.19	754,911	447,024	714,377	5.25	136,072
2016	1,279,537.23	746,392	441,979	837,558	6.25	134,009
2017	1,564,345.78	808,251	478,609	1,085,737	7.25	149,757
2018	3,000,146.19	1,350,066	799,447	2,200,699	8.25	266,751
2019	1,901,751.40	728,998	431,679	1,470,072	9.25	158,927
2020	4,257,877.66	1,348,342	798,427	3,459,451	10.25	337,507
2021	8,790,258.11	2,197,565	1,301,298	7,488,960	11.25	665,685
2022	12,174,235.92	2,231,903	1,321,631	10,852,605	12.25	885,927
2023	4,044,701.03	471,895	279,435	3,765,266	13.25	284,171
2024	1,990,605.90	99,530	58,937	1,931,669	14.25	135,556
2025	123,134.97	985	583	122,552	14.88	8,236
	45,255,752.18	15,462,665	10,662,094	34,593,658		3,448,470
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.0						7.62

KENTUCKY POWER COMPANY

ACCOUNT 398.00 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL  
RELATED TO ORIGINAL COST AS OF MARCH 31, 2025

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE NET SALVAGE PERCENT.. 0						
2005	30,390.25	30,010	30,390			
2006	59,954.48	56,207	59,361	593	1.25	474
2007	169,092.56	150,070	158,491	10,602	2.25	4,712
2008	41,951.41	35,134	37,105	4,846	3.25	1,491
2009	84,035.71	66,178	69,891	14,145	4.25	3,328
2011	73,274.73	50,376	53,203	20,072	6.25	3,212
2012	8,941.26	5,700	6,020	2,921	7.25	403
2013	509,592.74	299,386	316,185	193,408	8.25	23,443
2014	33,051.03	17,765	18,762	14,289	9.25	1,545
2015	63,913.31	31,158	32,906	31,007	10.25	3,025
2016	9,101.57	3,982	4,205	4,897	11.25	435
2017	9,387.79	3,638	3,842	5,546	12.25	453
2018	556,993.94	187,985	198,534	358,460	13.25	27,054
2019	19,912.03	5,725	6,046	13,866	14.25	973
2020	86,683.83	20,587	21,742	64,942	15.25	4,258
2021	373,053.76	69,948	73,874	299,180	16.25	18,411
2022	18,589.87	2,556	2,699	15,891	17.25	921
2023	17,668.71	1,546	1,633	16,036	18.25	879
2025	2,282.32	14	15	2,267	19.88	114
	2,167,871.30	1,037,965	1,094,904	1,072,967		95,131
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..						11.3 4.39

## Appendix A



**JOHN SPANOS**

**DEPRECIATION EXPERIENCE**

**Q. Please state your name.**

A. My name is John J. Spanos.

**Q. What is your educational background?**

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

**Q. Do you belong to any professional societies?**

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

**Q. Do you hold any special certification as a depreciation expert?**

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

**Q. Please outline your experience in the field of depreciation.**

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in

the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy

Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills Kansas

Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire; FirstEnergy Service Corporation; Northeast Ohio Natural Gas Corporation; Blue Granite Water Company; Spire Missouri, Inc.; Dominion Energy South Carolina, Inc.; South FirstEnergy Operating Companies; Dayton Power and Light Company; Liberty Utilities; East Kentucky Power Cooperative; Bangor Natural Gas; Hanover Borough Municipal Water Works; West Virginia American Water Company; Evergy Metro; Evergy Missouri West; Granite State Electric; Bluegrass Water; The Borough of Ambler; Newtown Artesian Water Company and Connecticut Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

**Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?**

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the

Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission (“FERC”); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

**Q. Have you had any additional education relating to utility plant depreciation?**

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.:

“Techniques of Life Analysis,” “Techniques of Salvage and Depreciation Analysis,”  
“Forecasting Life and Salvage,” “Modeling and Life Analysis Using Simulation,” and  
“Managing a Depreciation Study.” I have also completed the “Introduction to Public Utility  
Accounting” program conducted by the American Gas Association.

**Q. Does this conclude your qualification statement?**

A. Yes.

# LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
01. 1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02. 1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03. 1999	PA PUC	R-00994605	The York Water Company	Depreciation
04. 2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05. 2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06. 2001	PA PUC	R-00017236	The York Water Company	Depreciation
07. 2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08. 2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09. 2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10. 2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11. 2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12. 2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13. 2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14. 2003	PA PUC	R-0027975	The York Water Company	Depreciation
15. 2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16. 2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17. 2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18. 2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19. 2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20. 2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21. 2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22. 2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23. 2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24. 2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25. 2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26. 2004	PA PUC	R-00049165	The York Water Company	Depreciation
27. 2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28. 2004	OH PUC	04-680-EL-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29. 2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30. 2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31. 2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32. 2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation



33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

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<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
66. 2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67. 2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68. 2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69. 2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70. 2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71. 2008	DE PSC	08-96	Artesian Water Company	Depreciation
72. 2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73. 2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74. 2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75. 2008	IN URC	43501	Duke Energy Indiana	Depreciation
76. 2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77. 2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78. 2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79. 2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80. 2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81. 2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82. 2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83. 2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84. 2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85. 2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86. 2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87. 2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88. 2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89. 2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90. 2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91. 2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92. 2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93. 2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94. 2009	TX PUC	37744	Entergy Texas	Depreciation
95. 2009	TX PUC	37690	El Paso Electric Company	Depreciation
96. 2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97. 2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98. 2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

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<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
99.	2009		Aqua Ohio Water Company	Depreciation
100.	2009	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	WR-2010	Missouri American Water Company	Depreciation
102.	2009	U-09-097	Chugach Electric Association	Depreciation
103.	2010	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	ER09080664	Atlantic City Electric	Depreciation
111.	2010	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	R-2010-2157140	The York Water Company	Depreciation
113.	2010	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	2009-489-E	SCANA – Electric	Depreciation
117.	2010	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	2011-2232243	Pennsylvania American Water Company	Depreciation

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<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
133.	2011	FERC	RP11-____-000	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Depreciation
135.	2012	AK Reg Cm	U-12-009	Depreciation
136.	2012	MA PUC	DPU 12-25	Depreciation
137.	2012	TX PUC	40094	Depreciation
138.	2012	ID PUC	IPC-E-12	Depreciation
139.	2012	PA PUC	R-2012-2290597	Depreciation
140.	2012	PA PUC	R-2012-2311725	Depreciation
141.	2012	KY PSC	2012-00222	Depreciation
142.	2012	KY PSC	2012-00221	Depreciation
143.	2012	PA PUC	R-2012-2285985	Depreciation
144.	2012	DC PSC	Case 1087	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Depreciation
147.	2012	PA PUC	R-2012-2310366	Depreciation
148.	2012	PA PUC	R-2012-2321748	Depreciation
149.	2012	FERC	ER-12-2681-000	Depreciation
150.	2012	MO PSC	ER-2012-0174	Depreciation
151.	2012	MO PSC	ER-2012-0175	Depreciation
152.	2012	MO PSC	GO-2012-0363	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Depreciation
155.	2012	PA PUC	2012-2336379	Depreciation
156.	2013	NJ BPU	ER12121071	Depreciation
157.	2013	KY PSC	2013-00167	Depreciation
158.	2013	VA St CC	2013-00020	Depreciation
159.	2013	IA Util Bd	2013-0004	Depreciation
160.	2013	PA PUC	2013-2355276	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Depreciation
162.	2013	PA PUC	2013-2355886	Depreciation
163.	2013	TN Reg Auth	12-0504	Depreciation
164.	2013	ME PUC	2013-168	Depreciation
165.	2013	DC PSC	Case 1103	Depreciation
			Peoples TWP LLC	Depreciation
			Tennessee American Water	Depreciation
			Central Maine Power Company	Depreciation
			PHI Service Company – PEPCO	Depreciation
			York Water Company	Depreciation
			PHI Service Company– Atlantic City Electric	Depreciation
			Columbia Gas of Kentucky	Depreciation
			Virginia Electric and Power Company	Depreciation
			MidAmerican Energy Corporation	Depreciation
			Pennsylvania American Water Company	Depreciation
			Consolidated Edison of New York	Depreciation
			Kansas City Power and Light	Depreciation
			KCP&L Greater Missouri Operations Company	Depreciation
			Laclede Gas Company	Depreciation
			Integrus – MN Energy Resource Group	Depreciation
			Aqua Texas	Depreciation
			Duke Energy Ohio (Electric)	Depreciation
			Duke Energy Ohio (Gas)	Depreciation
			City of Lancaster – Sewer Fund	Depreciation
			Columbia Gas of Pennsylvania	Depreciation
			ITC Holdings	Depreciation
			Peoples Natural Gas Company	Depreciation
			Potomac Electric Power Company	Depreciation
			Louisville Gas and Electric Company	Depreciation
			Kentucky Utilities Company	Depreciation
			Borough of Hanover – Bureau of Water	Depreciation
			PPL Electric Utilities	Depreciation
			Idaho Power Company	Depreciation
			El Paso Electric Company	Depreciation
			Columbia Gas of Massachusetts	Depreciation
			Chugach Electric Association	Depreciation
			Avista Corporation	Depreciation
			Carolina Gas Transmission	Depreciation

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	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192.	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

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<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
200.	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

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233.	2016	PA PUC	West Penn Power Company	Depreciation
234.	2016	PA PUC	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	KCP&L Missouri	Depreciation
237.	2016	AR PSC	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	Idaho Power Company	Depreciation
240.	2016	OR PUC	Idaho Power Company	Depreciation
241.	2016	ILL CC	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	Chugach Electric Association	Depreciation
246.	2017	MA DPU	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	El Paso Electric Company	Depreciation
248.	2017	WA UTC	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	Portland General Electric	Depreciation
258.	2017	FERC	Jersey Central Power & Light	Depreciation
259.	2017	FERC	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	Laclede Gas Company	Depreciation
265.	2017	MO PSC	Missouri Gas Energy	Depreciation



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	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

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<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
301. 2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302. 2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303. 2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304. 2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305. 2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306. 2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307. 2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308. 2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309. 2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310. 2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311. 2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312. 2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313. 2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314. 2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315. 2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316. 2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317. 2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318. 2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319. 2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320. 2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321. 2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322. 2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323. 2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324. 2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325. 2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326. 2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327. 2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328. 2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329. 2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330. 2019	HI PUC	Docket No. 2019-0117	Young Brothers, LLC	Depreciation
331. 2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
332. 2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
333. 2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
334. 2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
335. 2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
336. 2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
337. 2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
338. 2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	VA St CC	Virginia Natural Gas Company	Depreciation
340.	2020	SC PSC	Dominion Energy South Carolina, Inc.	Depreciation
341.	2020	WV PSC	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
342.	2020	VA St CC	Aqua Virginia, Inc.	Depreciation
343.	2020	PA PUC	City of Bethlehem – Bureau of Water	Depreciation
344.	2020	NE PSC	Black Hills Nebraska	Depreciation
345.	2020	NY PSC	Central Hudson Gas & Electric Corporation	Depreciation
346.	2020	FERC	Duke Energy Indiana	Depreciation
347.	2020	FERC	Northern Indiana Public Service Company	Depreciation
348.	2020	OR PSC	PacifiCorp	Depreciation
349.	2020	MD PSC	Potomac Edison – Maryland	Depreciation
350.	2020	IN URC	Southern Indiana Gas and Electric Company	Depreciation
351.	2020	IN URC	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery	Depreciation
352.	2020	KY PSC	Kentucky Utilities Company	Depreciation
353.	2020	KY PSC	Louisville Gas and Electric Company	Depreciation
354.	2020	FERC	South FirstEnergy Operating Companies	Depreciation
355.	2020	OH PUC	Dayton Power and Light Company	Depreciation
356.	2020	OR PSC	Northwest Natural Gas Company	Depreciation
357.	2020	MO PSC	Ameren Missouri Gas	Depreciation
358.	2021	KY PSC	East Kentucky Power Cooperative	Depreciation
359.	2021	MPUC	Bangor Natural Gas	Depreciation
360.	2021	PA PUC	Columbia Gas of Pennsylvania, Inc.	Depreciation
361.	2021	NC Util.	Public Service of North Carolina	Depreciation
362.	2021	MO PSC	Ameren Missouri	Depreciation
363.	2021	PA PUC	Duquesne Light Company	Depreciation
364.	2021	KS PSC	Black Hills Kansas Gas	Depreciation
365.	2021	KY PSC	Duke Energy Kentucky	Depreciation
366.	2021	OR PSC	Portland General Electric	Depreciation
367.	2021	ILL CC	North Shore Gas Company	Depreciation
368.	2021	FERC	Duke Energy Progress	Depreciation
369.	2021	FERC	Duke Energy Carolina	Depreciation
370.	2021	KY PSC	NiSource Columbia Gas of Kentucky	Depreciation
371.	2021	MD PSC	NiSource Columbia Gas of Maryland	Depreciation
372.	2021	OH PUC	Aqua Ohio	Depreciation
373.	2021	PA PUC	Hanover Borough Municipal Water Works	Depreciation
374.	2021	OR PSC	Idaho Power Company	Depreciation
375.	2021	ID PUC	Idaho Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
376.	2021	6690-DU-104	Wisconsin Public Service Company	Depreciation
377.	2021	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
378.	2021	Case No. 21-637-GA-AIR;	NiSource Columbia Gas of Ohio	Depreciation
		Case No. 21-638-GA-ALT;		
		Case No. 21-639-GA-UNC;		
		Case No. 21-640-GA-AAM		
379.	2021	Texas PUC Docket No. 52195;	El Paso Electric	Depreciation
		SOHA Docket No. 473-21-2606		
380.	2021	Case No. GR.2021-0108	Spire Missouri	Depreciation
381.	2021	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
382.	2021	ER21-2736	Duke Energy Carolinas	Depreciation
383.	2021	ER21-2737	Duke Energy Progress	Depreciation
384.	2021	Cause #45621	Northern Indiana Public Service Company	Depreciation
385.	2021	Docket No. R-2021-3026682	City of Lancaster	Depreciation
386.	2021	Case No. 21-887-EL-AIR;	Duke Energy Ohio	Depreciation
		Case No. 21-888-EL-ATA;		
		Case No. 889-EL-AAM		
387.	2021	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
388.	2021	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
389.	2021	Case ER-22-392-001	El Paso Electric	Depreciation
390.	2021	Case ER-21-XXX	MidAmerican Electric	Depreciation
391.	2021	Docket Nos. R-2021-3027385,	Aqua Pennsylvania, Inc.	Depreciation
		R-2021-3027386	Aqua Pennsylvania Wastewater, Inc.	
392.	2022	Case ER-22-282-000	El Paso Electric	Depreciation
393.	2022	Docket No. 22-0154	MidAmerican Gas	Depreciation
394.	2022	Case No. ER-2022-0129	Eversgy Metro	Depreciation
395.	2022	Case No. ER-2022-0130	Eversgy Missouri West	Depreciation
396.	2022	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
397.	2022	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
398.	2022	R-2022-3031672; R-2022-3031673	Pennsylvania-American Water Company	Depreciation
399.	2022	Docket No. NG22-	MidAmerican Gas	Depreciation
400.	2022	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
401.	2022	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power	Depreciation
402.	2022	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
403.	2022	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
404.	2022	UM2213	Northwest Natural Gas	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
405.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
406.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation
407.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
408.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
409.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
410.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
412.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
413.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
414.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
415.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
416.	2022	NC Util Com	Docket No. E-22, Sub 493	Virginia Electric and Power Company	Depreciation
417.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
418.	2022	NJ BPU	BPU Docket No. ER2303144	Jersey Central Power & Light Company	Depreciation
419.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
420.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
421.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
422.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
423.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
424.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
425.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison	Depreciation
426.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
427.	2023	ILL CC	Docket No. 23-0066	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
428.	2023	SC PSC	Docket No. 2023-70-G	Dominion Energy South Carolina, Inc.	Depreciation
429.	2023	FERC	Docket No. ER23-xxx-00	Duke Energy Ohio, Inc.	Depreciation
430.	2023	WY PSC	Docket No. 30036-78-GR-23	Black Hills Wyoming Gas Company d/b/a Black Hills Energy	Depreciation
431.	2023	MD PSC	Case No. 9695	The Potomac Edison Company	Depreciation
432.	2023	OR PUC	Case No. UM2277	Avista Corporation	Depreciation
433.	2023	FERC	Docket No. ER23-1629-000	PPL Electric Utilities	Depreciation
434.	2023	OH PUC	Case No. 23-0154-GA-AIR	Northeast Ohio Natural Gas Corporation	Depreciation
435.	2023	DE PSC	PSC Docket No. 23-0601	Artesian Water Company	Depreciation
436.	2023	CO PUC	No. 23AL-0231G	Black Hills Colorado d/b/a Black Hills Energy	Depreciation
437.	2023	NH PUC	Docket No. DE 23-039	Granite State Electric d/b/a Liberty Utilities	Depreciation
438.	2023	MD PSC	Case No. 9701	Columbia Gas of Maryland	Depreciation
439.	2023	NY PSC	Case Nos. 23-E-0418; 23-G-0419	Central Hudson Gas and Electric	Depreciation
440.	2023	FERC	Docket No. ER23-xxx-000	Central Maine Power Company	Depreciation
441.	2023	SD PUC	Docket Number EL23-016	Northwestern Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

Year	Jurisdiction	Docket No.	Client Utility	Subject
442.	2023	CT PURA	Connecticut Water Company	Depreciation
443.	2023	Docket No. 23-08-32	The East Ohio Gas Company d/b/a Dominion Energy Ohio	Depreciation
444.	2023	Case 23-0894-GA-AIR	Indianapolis Power & Light	Depreciation
445.	2023	Cause No. 45911	Northern Indiana Public Service Company	Depreciation
446.	2023	Cause No. 45967	Pennsylvania-American Water Company	Depreciation
		Docket No. R-2023-3043189 and Docket No. R-2023-3043190		
447.	2023	Cause No. 45988	Citizens Energy Group	Depreciation
448.	2023	Case No. 23-G-0627	National Fuel Gas Distribution Corporation	Depreciation
449.	2023	Cause No. 45990	Southern Indiana Gas and Electric Company d/b/a	Depreciation
450.	2023	Docket No. R-2023-3044549	Peoples Natural Gas Company LLC	Depreciation
451.	2023	Docket No. UM-2312	Northwest Natural Gas Company	Depreciation
452.	2023	Docket No. WS-21182A-23-2092	Northwest Natural Water Company, LLC	Depreciation
453.	2023	Docket No. 2023-388-E	Duke Energy Carolinas	Depreciation
454.	2024	Docket No. ER24-768-000	Duke Energy Progress	Depreciation
455.	2024	Docket No. ER24-2057	Duke Energy Carolina	Depreciation
456.	2024	Docket No. SPP-0007	Evergny Metro, Inc. and Evergy Missouri West, Inc.	Depreciation
457.	2024	Docket No. WR24010057	Aqua New Jersey, Inc.	Depreciation
458.	2024	Docket No. 24-0044	Aqua Illinois, Inc.	Depreciation
459.	2024	Docket No. R-2024-3046519	NiSource – Columbia Gas of Pennsylvania, Inc.	Depreciation
460.	2024	Case No. 2024-00092	NiSource – Columbia Gas of Kentucky, Inc.	Depreciation
461.	2024	Case No. PUR-2024-00030	NiSource – Columbia Gas of Virginia, Inc.	Depreciation
462.	2024	Docket No. 24-	Northwestern Energy	Depreciation
463.	2024	Docket No. RPU-2023-0002	Alliant - Interstate Power and Light Company	Depreciation
464.	2024	Docket No. R-2024-3047068	FirstEnergy Pennsylvania – Metropolitan Edison; Pennsylvania Electric; Pennsylvania Power; West Penn Power	Depreciation
465.	2024	Docket No. R-2024-3046523	Duquesne Light Company	Depreciation
466.	2024	Docket No. E-22, Sub 694	Dominion Energy North Carolina	Depreciation
467.	2024	IURC Cause No. 46038	Duke Energy Indiana	Depreciation
468.	2024	Docket Nos. ER23120924 and GF 23120925	Public Service Electric and Gas Company	Depreciation
469.	2024	Docket No. 24-AL-0275E	Black Hills Colorado Electric, LLC	Depreciation
470.	2024	Case No. 24-0468-EL-AIR, Case No. 24-0469-EL-ATA, Case No. 24-0470-EL-AAM, Case No. 24-0471-EL-UNC	FirstEnergy Ohio	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
471.	2024	SD PUC	Docket No. NG24-005	Northwestern Energy	Depreciation
472.	2024	PA PUC	Docket No. R-2024-3047822	Aqua Pennsylvania, Inc	Depreciation
473.	2024	PA PUC	Docket No. R-2024-3047824	Aqua Pennsylvania Wastewater, Inc	Depreciation
474.	2024	NH PUC	Docket No. DE 24-070	Eversource Energy - Public Service of New Hampshire	Depreciation
475.	2024	VA SCC	Case No. PUR-2024-00048	Virginia Natural Gas Company	Depreciation
476.	2024	WV PSC	Case No. 24-0678-G-D	Hope Gas, Inc.	Depreciation
477.	2024	MO PSC	ER-2024-0319	Ameren Missouri	Depreciation
478.	2024	PA PUC	Docket No. R-2024-3050208	Newtown Artesian Water Company	Depreciation
479.	2024	PA PUC	Docket No. RP-24-1106-00	Adelphia Gateway	Depreciation
480.	2024	OH PUC	Case No. 24-0832-GA-AIR	Centerpoint Energy Ohio	Depreciation
481.	2024	MT PSC	Docket 2024-05-053	Northwestern Energy	Depreciation
482.	2024	MD PSC	Case No. 9754	NiSource – Columbia Gas of Maryland	Depreciation
483.	2024	OR PUC	UM 2363	Northwest Natural Gas Company	Depreciation
484.	2024	IURC	Cause No. 46120	Northern Indiana Public Service Company LLC	Depreciation
485.	2024	MO PSC	GR-2024-0369	Ameren Missouri	Depreciation
486.	2024	PUCO	Case No. 24-1009-EL-AIR, Case No. 24-1010-EL-AAM, Case No. 24-1011-EL-ATA	The Dayton Power and Light Company d/b/a AES Ohio	Depreciation
487.	2024	KY PSC	Case No. 2024-00354	Duke Energy Kentucky	Depreciation
488.	2024	MO PSC	GR-2025-0107	Spire Missouri, Inc.	Depreciation
489.	2024	OR PUC	UG 520	Northwest Natural Gas	Depreciation
490.	2024	TX PUC	SOAH Docket No. 473-25-11219; PUC Docket No. 57568	El Paso Electric	Depreciation
491.	2024	FERC	Docket No. RP24-1106-002	Adelphia Gateway, LLC	Depreciation
492.	2025	PA PUC	Docket No. R-2025-3053499	Columbia Gas of Pennsylvania, Inc.	Depreciation
493.	2025	NE PSC	Case No. NG-124	Black Hills Nebraska	Depreciation
494.	2025	KY PSC	Case No. 2025-00114	Louisville Gas and Electric	Depreciation
495.	2025	KY PSC	Case No. 2025-00113	Kentucky Utilities	Depreciation
496.	2025	PA PUC	Docket No. R-2025-2025-3053442, R-2025-3053573	The York Water Company	Depreciation
497.	2025	NC UC	Docket No. W-218, Sub 629	Aqua North Carolina, Inc.	Depreciation
498.	2025	TX PUC	Docket No. 58124	Aqua Texas, Inc.	Depreciation
499.	2025	FERC	Docket No. ER25-2479-000	Duke Energy Indiana, LLC	Depreciation
500.	2025	IURC	Cause No. 46258	Indianapolis Power & Light Company d/b/a AES Indiana	Depreciation
501.	2025	NY PSC	Case 25-E-0375 & Case 25-G-378	New York State Electric and Gas Corporation	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
502.	2025	NY PSC	Case 25-E-0379 & Case 25-G-0380	Rochester Gas and Electric Corporation	Depreciation
503.	2025	ILL CC	Docket No. 25-0055	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
504.	2025	CA PUC	A.25-01-001	San Gabriel Water Company	Depreciation
505.	2025	FERC	Docket EL25-77-000	Valley Link	Depreciation
506.	2025	KY PSC	Docket No. 2025-00125	Duke Energy Kentucky	Depreciation
507.	2025	KY PSC	Docket No 2025-00208	East Kentucky Power Cooperative	Depreciation