COMMONWEALTH OF KENTUCKY

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the matter of,

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

REBUTTAL TESTIMONY OF

EUGENE L. SHLATZ

ON BEHALF OF KENTUCKY POWER COMPANY

**REBUTTAL TESTIMONY OF
EUGENE L. SHLATZ ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

CASE NO. 2023-00159

TABLE OF CONTENTS

Exhibits

Resume of Eugene L. Shlatz	Exhibit No. ELS-1
Independent Review & Assessment of Reliability Performance and Distribution System Investments	Exhibit No. ELS-2

REBUTTAL TESTIMONY OF
EUGENE L. SHLATZ ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

I. INTRODUCTION

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

A. My name is Eugene L. Shlatz. I have been employed in various capacities by Guidehouse Inc. (Guidehouse)[1] since 1999, including twelve years as a Director in Guidehouse's Energy, Sustainability & Infrastructure Practice. My business address is 77 South Winooski Ave., Burlington, Vermont.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND

A. I have more than 30 years' experience in electric utility operations, engineering, and electric pricing. I have worked for Guidehouse over the past 23 years, where I was responsible for managing studies of electric utility system reliability, renewable energy, and advanced energy systems. I recently retired from Guidehouse, but continue to offer the same services that I previously provided as a full-time consultant.[2] I have supported filings before federal, state, and Canadian provincial regulatory commissions on a range of electric utility matters, including system planning and operations, reliability, renewables integration, and retail and wholesale rates.

[1] Previously, Navigant Consulting, Inc.
[2] Mr. Shlatz currently is assigned Contingent Worker status by Guidehouse.

I hold Bachelors and Master's degrees in Electric Power Engineering from Rensselaer Polytechnic Institute and am a registered Professional Engineer in Vermont, specializing in electrical engineering. I am a member of the Institute of Electrical and Electronics Engineers ("IEEE") and previously was a Section Chair in the State of Vermont. I have been responsible for numerous technical and economic studies of electric supply and reliability for investor-owned, municipal, and cooperative electric utilities throughout North America and worldwide. My experience includes evaluation of electric system reliability, distribution system planning and design, electric operations, and capital planning. As it relates to Kentucky Power's rate filing, I have testified before state utility commissions on electric reliability, distribution system planning, system design, emergency storm response, and the approval of capital projects proposed for inclusion in electric rates. I previously was employed by Green Mountain Power in various positions of increasing responsibility, including Director of Engineering and Operations, where I was responsible for the planning, design, and operation of the Company's generation, transmission, and distribution systems. My qualifications and previous appearances before regulatory agencies appear in more detail in Exhibit No. ELS 1.

Guidehouse regularly consults for electric investor-owned, municipal, and cooperative utilities in addition to state and federal agencies. As a matter of practice, Guidehouse is committed to maintaining an independent and unbiased approach to its engagements.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY PUBLIC SERVICE OR UTILITY REGULATORY COMMISSION?

A. Yes, I have testified as an expert witness in retail rate filings that addressed reliability and proposed investments in several other jurisdictions throughout North American including, Vermont, Montana, Nevada, Ontario. I have also testified as an expert witness before the Federal Energy Regulatory Commission to support Open Access Transmission Tariff filings on behalf of utilities in Montana, Indiana, New Mexico, and Florida. I have also testified on other matters involving electric reliability in Illinois, Colorado, and Arizona. The full list of appearances is presented in Exhibit ELS-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY?

A. My testimony addresses issues raised in data requests submitted by Commission Staff related to Kentucky Power's reliability performance and investments and that appropriate levels of investment has been made over the past several years.[3] Specially, my testimony provides compelling evidence that Kentucky Power's,

1. Reliability performance is consistent with those of a peer group of electric utilities with comparable service territory characteristics and distribution system attributes. However, additional spending in areas outlined in Kentucky Power's Proposed Distribution Reliability Rider ("DRR") and confirmed by pilot program results is needed to achieve its goal to improve reliability;

[3] See, for example data request nos. KPSC 2-19, KPSC 2-26, KPSC 3-19, KPSC 3-21, Walmart 1-11, AG-KIUC 2-15.

2. Prior levels of investment is consistent with those of the peer group, which is notable as Kentucky Power's electricity demand and number of customers served has declined over the past 10 years;
3. Level of spending on maintenance exceeds those of the peer utility group, particularly for vegetation management. However, as noted above, additional spending is needed to improve reliability;
4. Distribution system capacity planning and design standards are consistent with good utility practices, with appropriate levels of investment given electricity demand;
5. Distribution equipment maintenance practices and inspection intervals are consistent with good electric utility practice;
6. Proactive efforts to reduce customer interruptions caused by trees outside of the right-of-way ("TOR") is a practice that, subject to Commission approval of the proposed DRR, will further improve reliability performance;
7. Proactive efforts to further improve reliability from DRR investments targeting equipment replacements and distribution automation is consistent with good utility practice; and
8. Emergency (Storm) restoration processes and procedures, and the implementation of these procedures is consistent with good utility practice, resulting in restoration times that rival those of electric utilities encountering similar storms to those experienced in Kentucky.

The findings and conclusions listed above are supported by Guidehouse's comprehensive benchmarking analysis of Kentucky Power's reliability performance, planning and design, prior investments, vegetation management, restoration procedures, and benefits of proposed investments via the DRR. A report attached as Exhibit ELS- 2, *Independent Review & Assessment of Kentucky Power's Distribution Reliability Performance and Investments* supports my testimony and was prepared by myself with assistance from Guidehouse staff and an outside consulting firm working under my direction.[4]

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony addresses each of the eight topics listed above, sequentially, with evidence and rationale supporting conclusions I have reached based on the results of my analysis. First, I present the approach used to select a peer group of utilities to benchmark Kentucky Power's reliability performance, engineering standards and costs (*i.e.*, spending on distribution system investments and maintenance expense). I then describe the methods and sources I relied upon to support my findings and conclusions. Where applicable, I provide direct evidence in the form of charts and tables to further explain how I reached my conclusions.

III. ANALYTICAL APPROACH AND BENCHMARKING

Q. WHAT APPROACH DID YOU FOLLOW TO CONDUCT YOUR REVIEW OF KENTUCKY POWER'S RELIABILITY PERFORMANCE AND DISTRIBUTION SYSTEM INVESTMENTS?

A. My review and assessment were conducted via a comprehensive analysis of Kentucky Power's planning and design, investment levels and reliability performance. It utilizes a comprehensive data set, in some cases up to 15 years of data, obtained from Kentucky Power for each the areas listed below followed by a benchmarking of key performance and

[4] First Quartile Consulting provided electric benchmark data for several investment, performance and spending categories presented in my testimony and Guidehouse report.

cost metrics to those of peer group electric utilities with comparable service territory characteristics such as number of customers served and tree density.[5] It further relies on interviews I, along with Guidehouse subject matter experts, conducted with Kentucky Power personnel responsible for each area reviewed and benchmarked. Figure 1 lists the specific areas I reviewed and analyzed to address the topics listed in Section II.

Figure 1

Topics Assessed	Description
Benchmarking	Reliability metrics (SAIDI, SAIFI, CMI), spending (capital and maintenance)
Economic Growth	Historical and forecasted load and customer growth / contraction
Vegetation Management	Distribution vegetation standard, planned and completed work
Capacity Plans	Substation and feeder capacity, peak loads, and historical investments
Maintenance	Substation and distribution line maintenance, planned and completed
Engineering Standards	Distribution planning and design, and loading practices
Reliability Programs	Description and investment level of each reliability program
Grid Modernization	Description of program; planned and actual spending per year
Emergency Response	Incident Command Structure, mutual aid, and pre-planning
Storm Restoration	Customer restoration times and costs

Q. PRIOR TO EXPLAINING HOW YOU SELECTED A PEER GROUP OF ELECTRIC UTILITIES FOR BENCHMARKING RELIABILITY PERFORMANCE AND COSTS, PLEASE DESCRIBE HOW YOU CHARACTERIZE KENTUCKY POWER'S DISTRIBUTION SYSTEM.

A. Kentucky Power's distribution system is one that is comprised of long distribution lines serving low density load (*i.e.*, fewer customers per distribution line mile). Many circuits

[5] Certain cost and performance data was available for fewer than 15 years.

originating from Kentucky Power substations are rated 34.5kV with an average length exceeding 50 miles. Other Kentucky Power witnesses informed the Commission that many of its lines rated 34.5kV were constructed to serve remote mining load, several of which we have been informed are no longer operating. The departure of mining operations and decline in customers served over the past ten years likely has obviated the need for major capacity-related investments for load growth, which I address later in my testimony. Unlike other Investor Owned Utilities ("IOUs") in Kentucky, Kentucky Power does not serve major urban centers, which is one of the factors I considered in selecting a peer utility group for benchmarking reliability and costs. Lastly, Kentucky Power's distribution system is located in areas with very high tree coverage, with mountainous and difficult to access terrain. Collectively, each of these findings and observations create challenges when viewed in context with reliability performance. For example, the amount of damage and number of outages caused by trees during wind or ice storms and repairs can be more extensive than utilities with lower tree density.

Q. WHAT SOURCES DID YOU RELY ON TO IDENTIFY RELIABILITY PERFORMANCE AND COSTS OF THE BENCHMARKED UTILITIES?

A. I relied upon several sources to obtain data needed to accurately compare Kentucky Power's reliability and costs, including the U.S. Energy Information Agency for reliability statistics, FERC Form 1 for IOU capital costs and operation and maintenance expense ("O&M"), the U.S. Department of Agriculture ("USDA") Forest Service for state-level tree coverage, Integrated Resource Plans and 10K reports for distribution system data, utility web sites for various combinations of the preceding data and published reports.

Guidehouse also engaged First Quartile[6] consulting to provide maintenance and storm restoration benchmarks to supplement reliability and cost data obtained from the sources cited above.

Q. PLEASE DESCRIBE HOW YOU SELECTED A PEER GROUP OF UTILITIES FOR BENCHMARKING RELIABILITY PERFORMANCE AND COSTS.

A. The peer utility group includes IOU and Rural Electric Cooperatives ("RECs") with comparable service territories as measured by the relative number of customers served and tree coverage. Tree coverage was the primary selection criteria as the majority of Kentucky Power's customer interruptions are due to tree-related causes. The selection process and vetting of candidate utilities ensure peer group distribution system properties and characteristics align with Kentucky Power's distribution system. First, 61 utilities located in states with a high tree coverage and that reported reliability indices were chosen as candidate peer group utilities.[7] From this initial list, 19 municipal and four IOUs serving large urban areas were excluded; again, Kentucky Power serves predominantly rural areas. Next, of the remaining utilities, 15 were excluded because tree coverage in their respective service territories was below the established peer group threshold of 85 percent (Kentucky Power has tree coverage of 99%). Lastly, of the remaining 23 utilities, two were excluded because they serve less than 10,000 customers, leaving a net peer group of 21 utilities, including Kentucky Power.

[6] First Quartile obtains and reports benchmark data on a confidential basis, with the identify of individual utilities hidden in charts and tables to maintain confidentiality.
[7] Five states were selected, including Kentucky, West Virginia, Vermont, New Hampshire, Maine, and Louisiana.

Q. WHY DID YOU INCLUDE RURAL ELECTRIC COOPERATIVES IN THE PEER UTILITY GROUP?

A. Since RECs serve rural areas, which often have high tree coverage, their distribution systems often are most comparable to Kentucky Power's distribution system. Further, only RECs that report reliability indices (along with the IOUs) were compared to those reported to the Commission by Kentucky Power.[8]

IV. <u>RELIABILITY PERFORMANCE</u>

Q. HOW DOES KENTUCKY POWER'S RELIABILITY PERFORMANCE COMPARE TO THE PEER GROUP?

A. Kentucky Power's reliability as measured by average SAIFI[9] for normal weather events (*i.e.*, non-MED[10]) over the past 10 years compares favorably to the peer group average. Figure 2 presents Kentucky Power's average SAIFI versus the other 20 peer group utilities. I view SAIFI as a better measure of reliability performance as it indicates how many customers, on average, have experienced interruptions. It is also indicative of the capability of the utility's distribution system to withstand events that may cause interruptions. This is because SAIFI quantifies how often events cause distribution lines and equipment to fail or otherwise require protective devices to operate to minimize damage caused by external events such as tree contact. It also contradicts claims that Kentucky Power has not sufficiently invested in its distribution system. Outage duration, as measured by SAIDI,

---

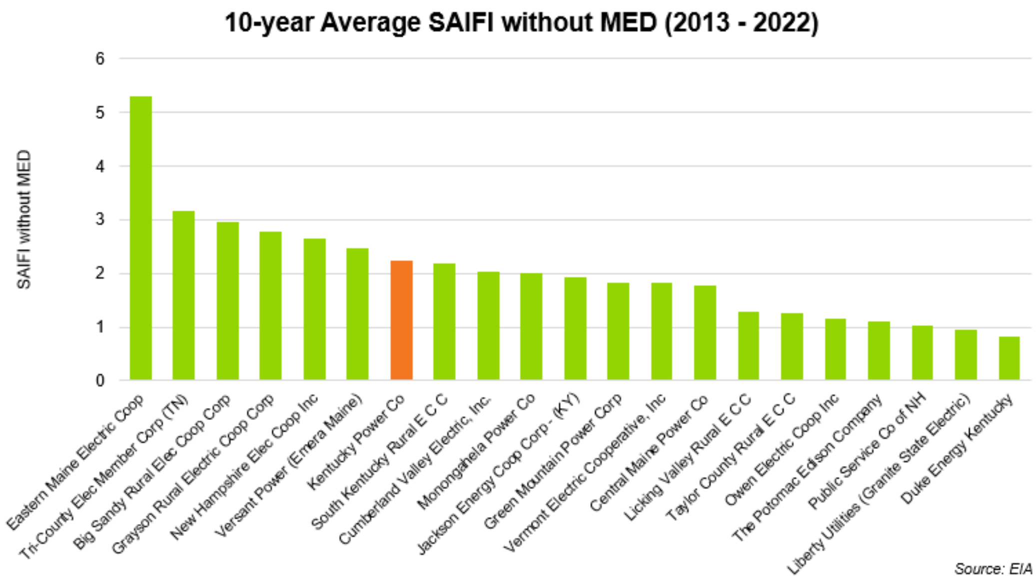
[8] Unlike IOUs, which report costs in FERC Form 1 reports, RECs typically do not report cost data via published reports or on their web sites.

[9] System average interruption frequency index.

[10] Major Event Day, as defined in IEEE P1366 standard. MED's include storms and other events that are significantly above average of most recorded interruptions and derived using a logarithmic statistical analysis.

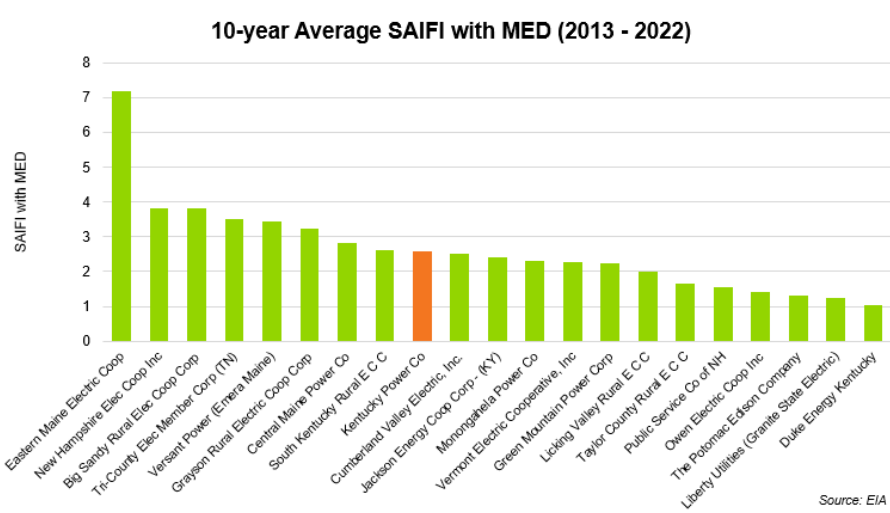
indicates how long it takes, on average, to restore service to customers following an event that causes an interruption of service; but it should not be used to assess the capability of distribution lines and equipment to withstand storms and abnormal events.

Figure 2



When all customer interruptions are counted, including Major Event Day ("MEDs"), Kentucky Power's reliability indices for non-MED SAIFI are near the peer group average. Figure 3 presents SAIFI indices for the peer group with MEDs included.

Figure 3



Q. HOW DOES KENTUCKY POWER'S RELIABILITY COMPARE TO THE PEER GROUP AVERAGE FOR OUTAGE DURATION?

A. The length of time Kentucky Power required to restore electric service to customers as measured by SAIDI[11] is above the peer group average. Figure 4 presents Kentucky Power's non-MED SAIDI over the past 10 years.

Figure 4

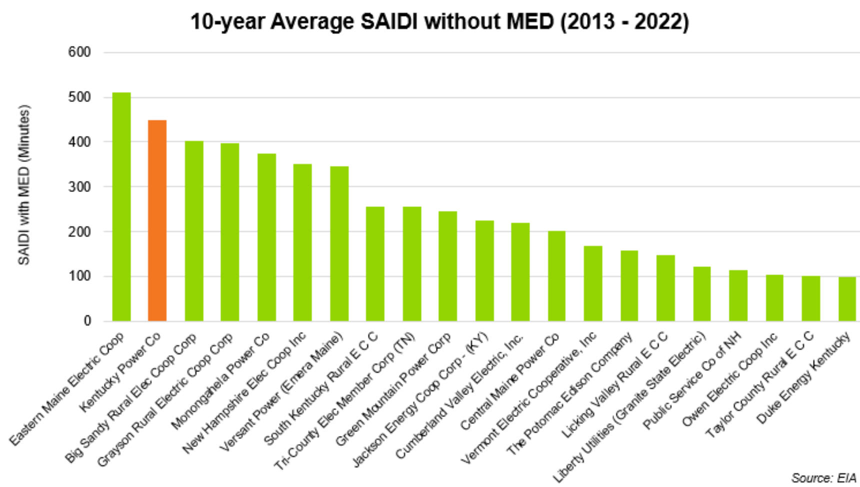
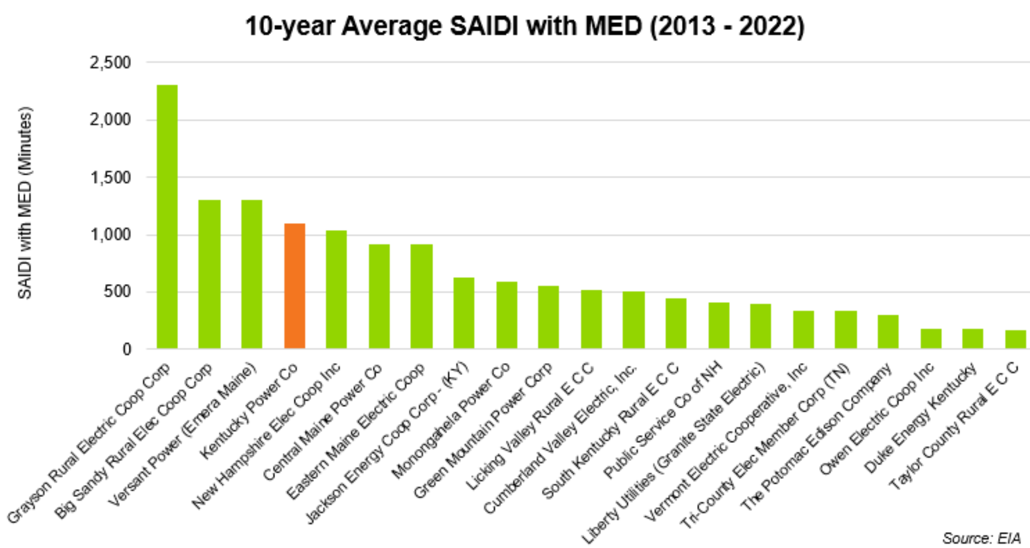


Figure 5 indicates Kentucky Power's reliability performance as measured by SAIDI when MED is included improves when compared to non-MED performance for the peer group average. While the improvement in MED SAIDI is modest, results confirm that Kentucky Power's distribution system is as resilient as those of the peer group during major storm events. As mentioned earlier in my testimony, Kentucky Power's tree coverage is among the highest in the peer group. Given the dominance of tree-related outages during major events such as continuous high winds, snow and ice storms, coupled with the length of time required by utility crews to traverse long distribution circuits, Kentucky Power's reliability performance as measured by SAIDI should not be considered exceptionally high. However,

[11] System average interruption duration index.

given Kentucky Power's goal to reduce SAIDI, its proposal to widen distribution ROWs via the proposed TOR program should serve to reduce SAIDI during MEDs.

Figure 5



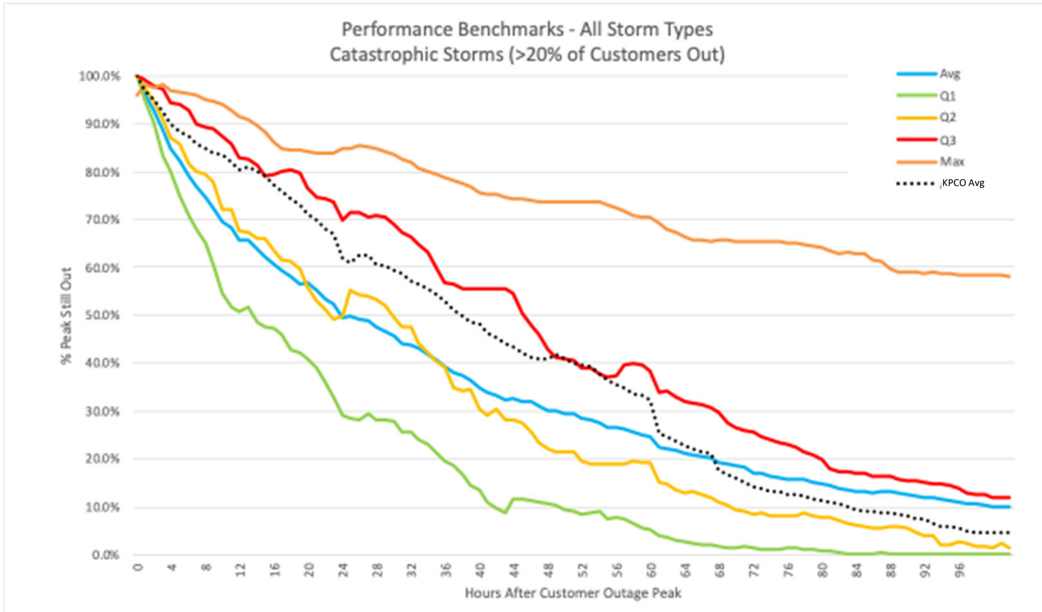
Q. ARE THERE OTHER FACTORS THAT SHOULD BE CONSIDERED WHEN COMPARING KENTUCKY POWER'S RELIABILITY PERFORMANCE TO THE UTILITY PEER GROUP?

A. Yes. Kentucky Power, like other utilities in the state, includes planned outages when reporting reliability performance (e.g., SAIFI and SAIDI) to the Commission. In contrast, my experience indicates that many utilities exclude planned outages when reporting reliability indices, consistent with IEEE P1366 guidelines. The reliability indices I obtained for the peer group utility were obtained from a U.S. Energy Information Agency database that is intended to exclude planned events. However, I was unable to determine if any of the peer group utilities exclude planned outages. However, by removing planned outages, Kentucky Power's reported values for customer interruptions~~minutes~~ is 15 percent lower and customer minutes of interruption is lower by 11 percent; each of which would improve benchmark performance compared to the peer group average if other utilities excluded planned outages in their reliability reporting.

Q. MOVING TO RESTORATION PERFORMANCE DURING MAJOR STORM EVENTS, HOW DOES KENTUCKY POWER CUSTOMER RESTORATION TIMES COMPARE TO OTHER UTILITIES?

A. Once storms have caused the greatest impact and the maximum number of customers have lost service, Kentucky Power's ability to restore service to these customers compares favorably to utility benchmarks. Figure 6 compares Kentucky Power's percent restoration to the First Quartile benchmark utility group for major storm events; *i.e.*, in this instance, those interrupting more than 20 percent of the utilities' customers. The percentage of Kentucky Power's customers remaining with service restoration pending, as measured on an hourly basis, is just above the benchmark average and consistently below the performance of the benchmark utility group in the third quartile. Each quartile represents the average percentage of customers restored following the interval when the maximum number of customers were interrupted, with Quartile 1 as the benchmark group with the fastest restoration and Quartile 4, the slowest. The curve for Kentucky Power will move closer to the average (*i.e.,* to the left) following the implementation of the Distribution Automation [and] Circuit Reconfiguration~~Restoration (~~("DACR") component of the DRR, as the number of customers interrupted by distribution outage events will be reduced.

Figure 6



I view these results favorably, as Kentucky Power's distribution system is comprised of long distribution lines serving, on average, a lower number of customers – approximately 16 customers per mile ~~on circuits rated 34.5kV~~ as per Mr. Phillips' direct testimony – compared to the benchmark utilities, which collectively average 45 customers per circuit mile. Similarly, Mr. Phillips cites other Kentucky IOUs as having between 34 to 65 customers per distribution line mile.[12] Further, it is likely that the very high tree density of Kentucky Power's distribution system – 99 percent tree coverage is cited earlier in my testimony – causes a greater amount of damage from falling trees and limbs and requires more follow-up repairs compared to other utilities with less tree coverage.

[12] Everett Phillips prefiled testimony, p. 16, lines 22-23 and p. 17, line 1.

V. DISTRIBUTION INVESTMENTS AND RELIABILITY IMPROVEMENTS

Q. WHAT MEASURES HAS KENTUCKY POWER UNDERTAKEN TO ADDRESS THE NUMBER AND DURATION OF OUTAGES ON ITS DISTRIBUTION SYSTEM?

A. Kentucky Power has undertaken steps to improve reliability by targeting investments on circuits and equipment most prone to failures. Key among these is a program to formalize vegetation management activities to include the removal of at-risk trees located outside its distribution rights-of-ways ("TOR"). A pilot program implemented in 2018 resulted in a 15 percent reduction in TOR-related interruptions, an important result given that nearly 50 percent of customer interruptions, as measured by customer minutes of interruptions ("CMI"), are caused by trees located outside the distribution rights-of-way ("ROW"). It is also the impetus behind Kentucky Power's decision to pursue full implementation of the TOR program by investing $12 million annually over the next five years as proposed in its Distribution Reliability Rider ("DRR").

As part of its Distribution Asset Management program, which is part of Kentucky Power's Distribution Reliability programs, Kentucky Power has also replaced significant quantities of defective fused cutouts and porcelain insulators over the past several years, as these are the two leading causes of equipment failure as measured by CMI. Other at-risk or defective equipment identified in bi-annual inspections are repaired or removed on a prioritized basis. Kentucky Power has modernized its distribution system via the installation of fault detection and automatic transfer schemes via its DACR program ~~under the DRR~~[13] to reduce the number of customers interrupted by outages and to lower the time

[13] Also referred to as Fault Location, Identification, and Service Restoration or FLISR.

needed to repair the fault. Kentucky Power proposes to build upon successes achieved by each of the above initiatives by investing funds, incrementally, in each of the areas described above over the next five years as proposed in its DRR.

Lastly, Kentucky Power in 2014 adopted the National Electric Safety Code ("NESC") heavy loading design standard,[14] which is applied on a selective basis, as not all existing distribution line segments are suitable candidates for the heavy loading standard nor is Kentucky Power required to build to the heavy loading design standard; *i.e.*, mid-span pole installations may not be practicable in some locations so the medium design standard is appropriate in this example. Over time, as the Company continues to selectively upgrade its distribution system to NESC heavy loading, I expect the adoption of this design standard will further improve system reliability and resiliency during major storm events.

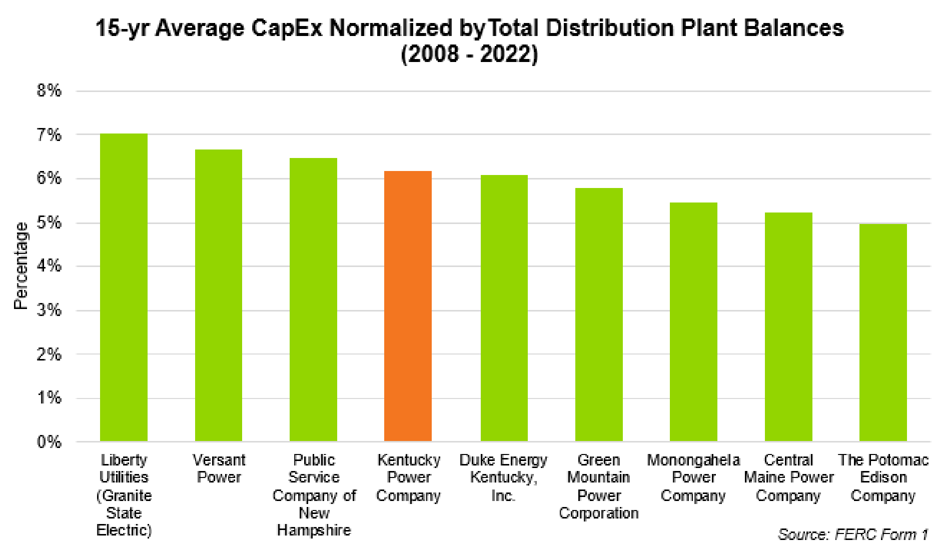
Taken together, the above measures that Kentucky Power has undertaken over the past several years demonstrate that it has proactively and responsibly addressed reliability performance and made appropriate investments to reduce both the number and duration of customer interruptions. Commission approval of the incremental investments Kentucky Power proposes in its DRR will build upon these prior efforts.

[14] Kentucky Power's service territory is located in a medium loading design standard per NESC regional maps.

Q. YOU MENTION IN YOUR ANSWER TO THE PRIOR QUESTION THAT KENTUCKY POWER HAS MADE AN APPROPRIATE LEVEL OF INVESTMENT IN ITS SYSTEM. WHAT EVIDENCE DO YOU HAVE TO CONFIRM THIS STATEMENT?

A. In addition to reliability, I compared Kentucky Power's spending on capital investments and maintenance expense to the IOU segment of the peer utility group using costs reported in their annual FERC Form 1 for the past 10 years.[15] For capital investments, I compared the 15-year average of the annual summation distribution plant additions for FERC distribution accounts 360 through 374 to total original plant balances for Kentucky Power to values derived for the IOU peer group. Figure 7 confirms Kentucky Power's annual distribution investments as a percent of total distribution plant balances over the past 15 years is within the peer group average.

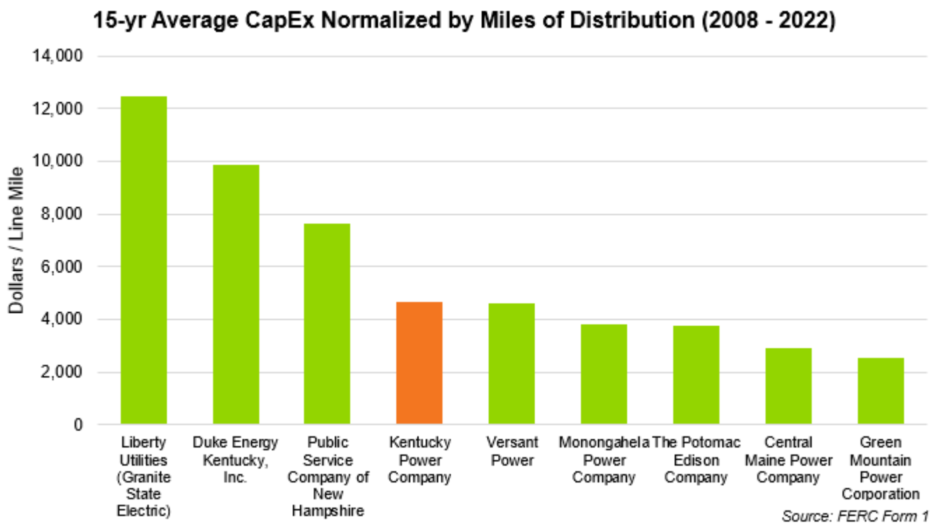
Figure 7



[15] The RECs do not prepare and submit FERC Form 1 and do not present costs via publicly available documents, and therefore, were excluded from peer group for cost benchmarks.

I also compared Kentucky Power's 15-year average annual distribution investments divided by total customers served to those of the IOU peer group. Figure 8 confirms results derived per customer served are similar to those derived using original distribution plant balances.

Figure 8

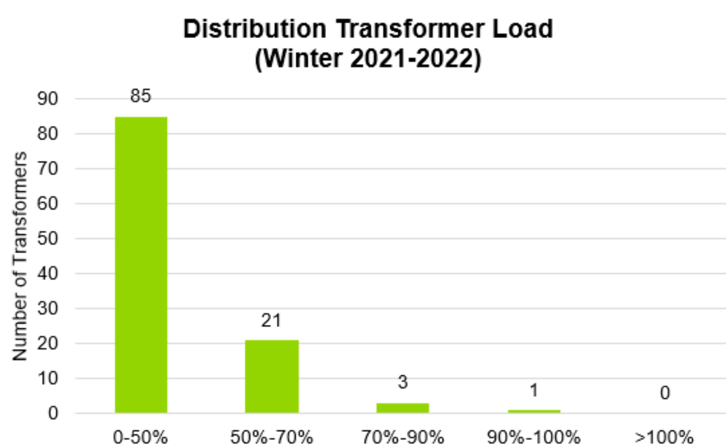


The conclusion I draw from these findings is that Kentucky Power's investment in its distribution system is on par with peer group IOUs with comparable distribution systems. My conclusion is further supported by the lower level of investment Kentucky Power needed solely for load growth – new substations and circuits are proposed in the DRR to improve reliability via enhanced feeder ties and load transfer capability. The number of customers served by Kentucky Power has declined by about 8,000 customers (almost a five percent reduction) while electric peak demand has dropped by almost 400 MW from its prior high of 1,400 MW in 2014. Accordingly, the amounts Kentucky Power needed to invest for capacity and customer growth alone were lower than other utilities in the peer group Thus, if values in the above chart were normalized to account for load growth, Kentucky Power's spending likely would appear even more favorable when compared to the peer utilities. However, because spending for new capacity in the past has been low does not preclude the need for addition investments proposed via the DRR to improve reliability.

Q. IN YOUR RESPONSE TO THE PRIOR QUESTION, YOU INDICATED THAT KENTUCKY POWER HAS REDUCED ITS SPENDING ON CAPACITY-RELATED INVESTMENTS. HAS THIS REDUCTION CAUSED EQUIPMENT TO BECOME OVERLOADED, RESULTING IN CUSTOMER INTERRUPTIONS?

A. No. Figure 9 presents substation transformer loadings as a percent of maximum rating as of winter 2022, grouped by loading intervals from less than 50 percent loaded to over 100 percent loaded.[16] Most transformers are well below their maximum rating, and none are above 100 percent. Comparable results were obtained for distribution circuits. Further, customer interruptions reported in Kentucky Power's reliability records, due to overloads, are near zero, thus confirming that it has not under-invested in substation or circuit capacity.

Figure 9

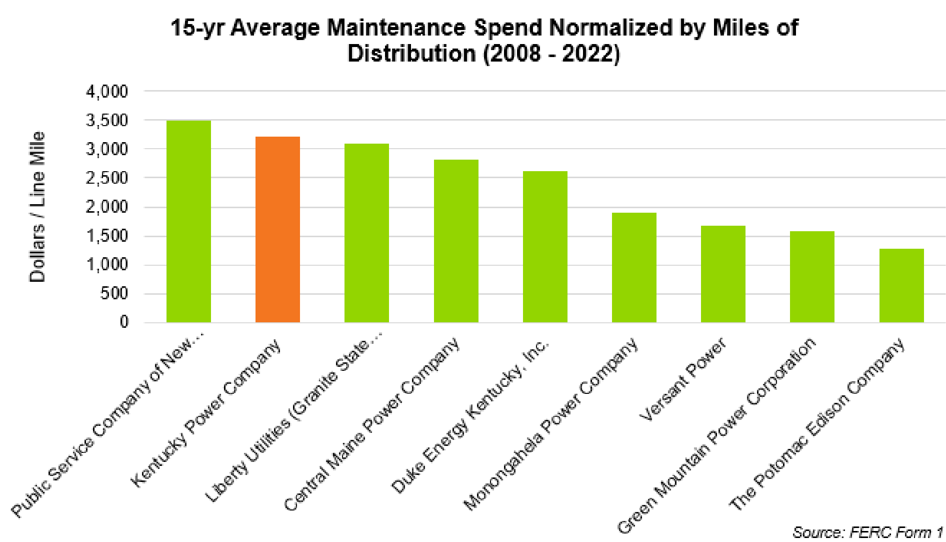


[16] Kentucky Power's peak demand occurs during winter months.

Q. IN TERMS OF MAINTENANCE, ARE KENTUCKY POWER'S EXPENSES ON MAINTENANCE SUFFICIENT TO ENSURE RELIABLE OPERATION OF ITS LINES AND EQUIPMENT?

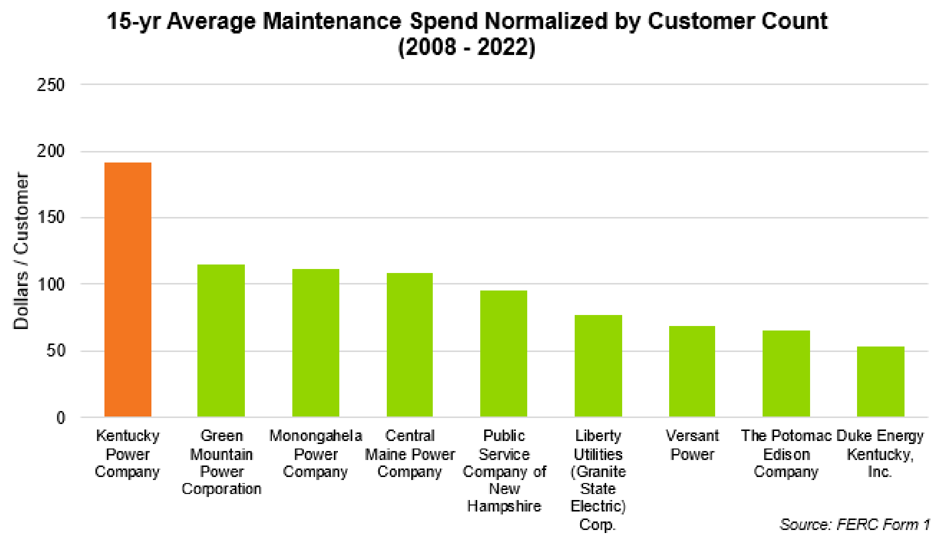
A. Yes. First, as I explain in the following section, Kentucky Power's maintenance programs and practices are consistent with good utility practice. I also compared the amounts Kentucky Power has spent on maintenance to those of the IOUs in the peer group over the last 15 years. Figure 10 indicates Kentucky Power's spending on maintenance per miles of distribution lines was above the peer group average. This finding is particularly notable as the average miles of line on Kentucky Power's distribution circuits is high, averaging over 50 miles for circuits rated 34.5kV.

Figure 10



I also compared the amounts Kentucky Power spent on maintenance on a per customer basis during the same time period. Figure 11 confirms the amounts Kentucky Power spends on maintenance is highest among the IOU peer group when calculated using the number of customers as the denominator. This finding is not unusual or unexpected, as the low customer density on Kentucky Power's distribution system invariably causes a further shift or spending on maintenance to the highest among the peer group.

Figure 11



The above results contradict suggestions or claims that Kentucky Power has underspent on distribution maintenance, particularly for vegetation management. The majority of the amount Kentucky Power spent was for ROW maintenance, mostly to maintain clearances for trees located within the distribution ROW. Kentucky Power's proposal to modestly increase the O&M for Trees within the ROW (TIR) ensures an appropriate level of spending is targeted to circuits most susceptible to tree-related interruptions.

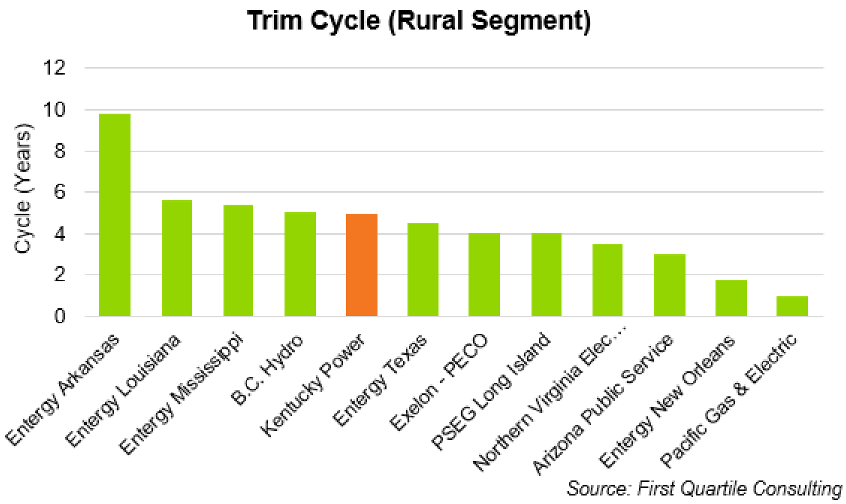
From a capital perspective and related to vegetation management, Kentucky Power also removes trees from outside of the ROW (TOR). Due to the fact that TOR alone causes almost 50 percent of total customer interruptions, Kentucky Power needs to increase spending on its TOR program to improve reliability as measured by SAIDI to meet Kentucky Power's reliability objectives.

VI. MAINTENANCE PRACTICES

Q. YOU INDICATE IN THE PREVIOUS SECTION THAT KENTUCKY POWER SPENDS APPROPRIATE AMOUNTS ON DISTRIBUTION MAINTENANCE. CAN YOU CONFIRM MAINTENANCE PRACTICES ARE CONSISTENT WITH GOOD UTILITY PRACTICE AND COMPLETED ON SCHEDULE?

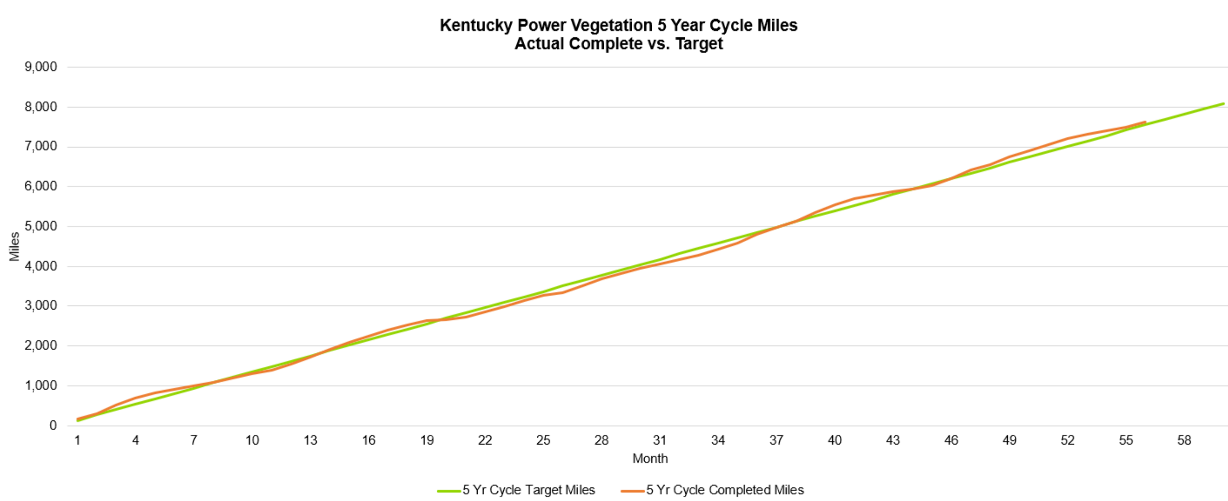
A. Yes. First, I address vegetation management, by far the largest component of Kentucky Power's distribution operation and maintenance (O&M) expense. I reviewed Kentucky Power vegetation management policies and procedures, including clearances, versus those of other utilities where I have conducted similar assessments. From my assessment, I can conclude that Kentucky Power's vegetation management program is consistent with good utility practices and comparable to those deployed by electric utilities with a high concentration of trees. The detailed specifications and requirements of contractors outlined in these procedures is thorough. The specification of minimum clearances by tree species is consistent with good industry practice, as is the removal of trees at risk of falling onto circuits from outside the distribution ROW. Kentucky Power's five-year cycle is also consistent with good utility practice. Figure 12 confirms Kentucky Power's five-year trim cycle is consistent with the First Quartile benchmark utility group for distribution circuits located in rural areas.

Figure 12



Equally important to Kentucky Power's vegetation management practices is its ability to meet trimming cycles on time. Figure 13 shows minimal variance between scheduled and completed tree trimming, thus confirming that Kentucky Power judiciously tracks and maintains trimming clearances in accordance with schedules.

Figure 13



Q. PLEASE ADDRESS KENTUCKY POWER'S MAINTENANCE PRACTICES FOR DISTRIBUTION CIRCUITS AND SUBSTATIONS.

A. Starting with distribution circuits, Kentucky Power complies with the Commission's 2-year inspection guidelines as outlined in Exhibit ELS-2. I view the two-year inspection cycle and inspection guidelines as a good practice, as my experience indicates, other utilities have longer inspection cycles or conduct them more sporadically. Kentucky Power also provided evidence that inspections are completed on time, with follow up action taken to address deficiencies on a prioritized basis. Figure 14 confirms that the number of devices Kentucky Power inspected over the past 15 years has been completed on time with minimal variance for most years, except for 2020 through 2022 when Covid-19 impacted utility work plans and schedules.

Figure 14

Year	Switched Cap		Fixed Cap	Recloser Electronic		Recloser Hydraulic		Regulator
	No. Inspections Completed	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices Inspected	No. Inspections Completed
2008	147	91	347	259	2017	1140	550	291
2009	268	84	391	292	1879	1084	607	316
2010	303	76	395	289	1928	1109	583	307
2011	327	88	437	311	1900	1097	611	323
2012	316	80	457	327	1816	1075	641	333
2013	299	74	490	353	1854	1055	618	319
2014	296	72	516	369	2079	1169	630	326
2015	283	71	533	392	1009	604	631	327
2016	278	69	552	414	1879	1066	619	319
2017	267	63	562	423	1567	875	626	326
2018	241	59	565	432	1317	746	595	304
2019	247	58	602	458	1387	742	624	322
2020	224	56	630	479	1926	1076	618	317
2021	80	42	646	512	988	541	471	236
2022	13	20	655	530	1423	767	439	227
2023	11	22	375	300	433	250	133	75
Total	**3827**	**1165**	**8773**	**6140**	**29160**	**14396**	**9968**	**5163**

Kentucky Power's pole inspection program, normally conducted on a 10-year cycle for poles exceeding an age threshold, is consistent with good utility practice, with inspection results for the five-year period between 2014 and 2018 presented in Figure 15 indicating a low percentage of poles, just over two percent, needing replacement due to loss of strength.

Figure 15

Inspection Results	Quantities
Non-Reject	32,448
Non-Restorable Reject	527
Priority Non-Restorable Reject	379
Priority Restorable Reject	611
Restorable Reject	284
Unset	1
Total	**34,250**

Kentucky Power's maintenance practices and policies for substation equipment are equally comprehensive as those followed for distribution circuits. Kentucky Power substation equipment maintenance is based on an AEP system-wide standard, which I reviewed and found to be comprehensive and consistent with those I have encountered in similar reviews for utilities throughout the U.S.[17] Importantly, each procedure recognizes differences in equipment type, manufacturer, design, testing requirements and other factors specific or unique to the device inspected or maintained. For example, power transformer maintenance schedule varies according to factors such as equipment supplier, core design, voltage, and other device-specific attributes.

Figure 16 confirms that Kentucky Power's equipment maintenance schedules conform to good industry practice. Further, Kentucky Power provided evidence via electronic records[18] that distribution maintenance, both line and substation, is performed as scheduled.

---

[17] Substation equipment maintenance is performed by the Transmission Field Services group.
[18] Kentucky Power collects and reports data in electronic format to ensure consistent reporting and a sole source for data capture.

Figure 16

Substation Maintenance Cycles	Average Cycle Time (12 Utilities)	Kentucky Power	Kentucky Power Comments
Power Transformers	5.1	4/5/8/10	Varies by transformer type
Relays	5.6	--	Follows NERC compliance
DC Supply (Batteries)	N/A	1	Annual detailed inspection
Circuit Breakers	5.6	6	For most breaker types

VII. SUMMARY ASSESSMENT

Q. PLEASE SUMMARIZE YOUR INDEPENDENT ASSESSMENT OF KENTUCKY POWER'S DISTRIBUTION SYSTEM RELIABILITY AND COSTS.

A. From the evidence I obtained via my analysis of Kentucky Power's reliability history for normal and major storms, I determined that reliability performance over the past 10 years is comparable to those of a peer group of electric utilities with similar service territories, as my selection of a peer group focused on those with similar tree coverage. While Kentucky Power's reported reliability indices are above those of larger utilities in Kentucky that serve urban load, differences in distribution circuit length, tree coverage and customer density are key factors that should be considered when comparing reliability performance. Kentucky Power's distribution system has longer lines, lower customer density and higher tree coverage, each of which are contributing factors to reliability performance. Kentucky Power's spending on capital and maintenance, particularly for vegetation management, is at or above those of the utility peer group and suggestions or claims that Kentucky Power has under-investing in its distribution system are unfounded and not based on the evidence I relied upon to support my findings and conclusions. The fact that Kentucky Power's spending on capital and maintenance is within the peer group average is notable given the decline in customers and electricity demand over the past 10 years. Despite the above, proposed incremental spending outlined in the DRR is needed to improve reliability as measured by SAIDI and CMI.

Kentucky Power historically has targeted spending in areas with the greatest reliability benefits, and proposes to build upon these past efforts to further improve reliability via its proposed DRR. Each of the findings cited above supports my conclusion that Kentucky Power has operated and maintained its distribution system in a responsible manner, with appropriate levels of investment to ensure safe and reliable electric service to its customers. Kentucky Power recognizes the need to further improve distribution reliability and has proposed spending via its DRR to achieve this objective.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Guidehouse
Outwit *Complexity*

Eugene L. Shlatz

Contractor – Contingent Worker

eshlatz@guidehouse.com
Direct: 802.233.1890

Professional Summary

Gene has over 35 years of management consulting and supervisory experience in energy delivery, power generation and distributed energy systems. In his prior role as a Director at Guidehouse, he directed engagements on electric system reliability, renewable technologies, microgrids, asset management, electric pricing, due diligence and system adequacy. His clients included US, Canadian, European and South American electric utilities, electricity consumers, law firms and government agencies. Gene is an expert on electric power delivery systems; and has testified before FERC, state commissions and the U.S. Congress on transmission open access, DG integration, retail rates, compliance, and capital planning. He has published numerous articles and industry presentations on smart grid, distributed resources, electric reliability, energy efficiency, and electric pricing.

Professional Experience

In Gene's prior role as a Director at Guidehouse, he directed project teams and managed consulting engagements for electric utility, government and energy supply clients. He was responsible for and continues to support energy delivery and power production engagements in the following areas:

- **Regulatory/Legal** – capital planning, transmission and distribution program support, renewables integration and pricing, expert witness for state and federal agencies, and civil litigation
- **Operations & Planning** – transmission and distribution performance evaluation; reliability, target setting, remediation analysis, and service quality standards
- **Emerging Technologies** – renewable technology and smart grid integration, energy efficiency and technical/economic assessment of distributed resources
- **Asset Management** – implementation strategy, project prioritization, performance measurement, utilization and cost optimization, electric delivery system planning

Representative Client List and Engagements

Distributed Energy Resources & Advanced Technologies

- **American Electric Power.** Program lead to assess DER integration strategies and cost for a multi-state solar PV and electric vehicle forecast. Developed analytical approach to predict system impacts and mitigation options to address distribution system performance violations.
- **Aspen/California Energy Commission**. Conducted several independent reviews of advanced energy systems and applications for applicants seeking EPIC project funding. Technologies evaluated include integrated storage and renewables, advanced simulation software and Microgrids.
- **NYSERDA**. Evaluated impacts of small-scale energy storage on radial and network distribution systems to assess the applicability of standby rates adjustments for New York electric utilities.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

» **California Utility (Confidential)**. In response to recent fires in California, evaluated wildfire prevention mitigation strategies to reduce the hazard potential for electric transmission and distribution lines and equipment.

» **Dubai Electric and Water Authority.** Project lead for distribution automation, transmission automation, asset management, and renewables integration smart technology assessment. Conducted technical and economic studies of smart technology options and developed roadmap for implementation of recommended strategies.

» **California Energy Commission/Southern California Edison**. Project manager of DER integration studies for a major utility planning region. Predicted hosting capacity limits and options to increase DER capacity and value via advanced communications and control technologies. Assessed the capability of energy storage to increase capacity limits.

» **U.S. Department of Energy/Dominion Virginia Power.** Project manager of Solar Integration Study to identify renewable capacity impacts and integration requirements in the state of Virginia. Determined distribution hosting capacity limits and impacts of increasing amounts of solar on DVP's generation, transmission and distribution system.

» **Los Angeles Department of Water & Power.** Technical lead of a DER integration study to determine integration requirements and hosting capacity limits, and approaches to target DER and storage based on locational needs and benefits. Assessed communication and control strategies, organization structure, tariffs and rates, and strategies to achieve renewable portfolio targets.

» **Orange & Rockland Utilities.** Project manager of a DG Interconnection benchmarking analysis. Conducting studies to predict hosting capacity limits on O&R's T&D system and mitigation options in support of NY's Renewable Energy Vision initiative.

» **Pacific Gas & Electric Company.** Project manager of a Transmission and Distribution PV Impact Study. It included engineering analyses designed to facilitate the integration of DGPV into the grid. Developed PV values based on analysis across multiple scenarios and attributable to DGPV.

» **Major Southeastern U.S. Utility (Confidential).** Project manager of a Solar Integration Study to assess the technical and economic impact of increasing amounts of solar on the utilities' generation, transmission and distribution system.

» **California Energy Commission/Southern California Edison.** Project manager of a study evaluating DG impacts and integration requirements for up to 12,000 MW of DG in California by 2020. Developed a technical evaluation and costing framework applicable to all CA utilities.

» **U.S. Navy.** Evaluated on-site microgrid options for a major military shipyard, including technical assessment of renewable generation, control strategies, electric system performance and system upgrades required to operate in stand-alone and parallel modes of operation.

» **U.S. Department of Energy (DOE).** Provided technical and program management support for DOE's Smart Grid Investment Grant (SGIG) program. Responsible for impact evaluation of smart grid technologies, including program benefits and implementation strategies.

» **PowerStream (Ontario).** Provided project management and evaluation services for an on-site microgrid comprised of a mix of wind, solar, storage and gas-fired technologies. Developing control and dispatch strategies and methods for assessing MG performance and benefits.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

- **NV Energy.** Project manager of DG and large PV integration studies for southern and northern Nevada. Identified technical/capacity limits of renewable energy sources on NV Energy's T&D system. Responsible for technical and economic evaluation of power system impacts and integration costs, including intermittency. Testified before Nevada Commission to support findings.
- **Toronto Hydro.** Project manager of comprehensive evaluation of distributed energy resources versus traditional T&D alternatives for a major urban center. Included a technical assessment of DG systems impacts, technology integration and forecast of cost-effective alternatives.
- **Southern California Edison Company.** Technical support a 3-year integrated grid pilot designed to demonstrate modern grid infrastructure functionality and advance customers' ability to interconnect renewable energy sources, proactively manage customer demand, and improve the safety and reliability of the grid in a cost-effective manner.

Reliability, Benchmarking and Electric System Planning

- **Jersey Central Power & Light.** Principle investigator of a commission-mandated Operations Review of JCP&L's distribution system. The review included an assessment of reliability, storm response, preventative maintenance and budgeting processes. Navigant's report and recommendations were unanimously approved and accepted by the New Jersey Board of Public Utilities.
- **Exelon/Commonwealth Edison.** Lead consultant of an engineering and operational assessment of Exelon's system design, construction and maintenance practices. Our study was filed before the ICC in response to claims of system inadequacy for major storms. Provided expert witness testimony that confirmed ComEd's T&D practices were consistent with or exceeded industry standards
- **Government of Puerto Rico (Public Private Partnership).** Program oversight lead for long-term disaster recovery efforts for the Puerto Rico Electric Power Authority (PREPA) generation, transmission and distribution systems. Responsible for developing Grid Modernization plans to restore the electric grid to current standards, consistent with FEMA and BBA funding requirements.
- **Toronto Hydro (THESL).** Prepared an independent technical assessment of a proposed relocation of a major segment urban transmission and distribution system as evidence before a tribunal in the City of Toronto. Analyzed relocation options and impact on power system reliability and performance.
- **New York Power Authority/ Puerto Rico Electric Power Authority**. Lead investigator and subject matter expert of a study to assess damage caused by major hurricanes in 2017 and to provide recommendations to bring the power generation and delivery system to current design standards.
- **Hawaiian Electric Company**. Project manager of a technical analysis to assess the impact of capital and O&M improvement programs on electric system reliability performance during storms and major events. Demonstrated a correlation of program improvements and system resiliency during storms.
- **BC Hydro.** Lead investigator to benchmark and assess vegetation management practices and applications across the province of British Columbia. Provided recommendations on enhancing processes and VM methods to improve efficiency and cost.
- **Saskatoon Light & Power.** Project manager of a 20-year capital development plan designed to meet reliability and performance objectives at lowest cost. Our assessment included a review and analysis of T&D engineering, maintenance and operations; and recommendations for improvement.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

- **Sulphur Springs Valley Electric Cooperative (SSVEC).** Project manager of an independent Feasibility Study of delivery alternatives, including T&D, distributed generation, energy efficiency, energy storage and renewables. Successfully testified as an expert witness before AZ commission.
- **Austin Energy.** Performed a benchmarking and gap analysis of AE's engineering and operations. Prepared recommendations to enhance reliability and operations efficiency.
- **Saskatoon Light & Power.** Project manager of a 20-year capital development plan designed to meet reliability and performance objectives at lowest cost. Our assessment included a review and analysis of T&D engineering, maintenance and operations; including recommendations for improvement.
- **Toronto Hydro Electric System, Limited (THESL).** Performed a long-range planning study for THESL's radial and network downtown distribution system. Evaluated capital expansion versus CDM needed to serve downtown Toronto for 20 years.
- **Sulphur Springs Valley Electric Cooperative (SSVEC)**. Project manager of an independent Feasibility Study of delivery alternatives, including T&D, distributed generation, energy efficiency, energy storage and renewables. Successfully testified as an expert witness before AZ commission.
- **Austin Energy.** Performed a benchmarking and gap analysis of engineering and operations performance for AE's energy delivery organization.
- **Ameren Services.** Conducted a review and predictive assessment of distribution reliability. A methodology was developed to apply fact-based methods to allocate reliability expenditures.
- **American Electric Power.** Conducted a review and predictive assessment of distribution reliability. Applied fact-based methods to prioritize investment decisions and to quantify risk.
- **Potomac Electric Power Company (PHI).** Conducted an investigation and benchmarking of PEPCO's T&D system, including transmission and distribution infrastructure. Prepared recommendations to enhance performance and reduce outage risk.
- **National Grid.** Conducted a system review and predictive assessment of distribution reliability. A strategic methodology was developed to predict system outage performance based on system attributes, equipment performance and historical reliability.
- **Potomac Electric Power Company (PHI).** Project manager of a benchmarking analysis of PEPCO's T&D system, including transmission and distribution infrastructure. Prepared recommendations to enhance performance and reduce outage risk.
- **Dominion – Virginia Power**. Project manager and lead investigator of a comprehensive technical review and risk assessment of secondary networks. Reviewed and analyzed engineering standards, planning criteria, operations and maintenance, and construction methods.

Regulatory and Legal

- **Expert Witness - Civil Litigation (Various Jurisdictions).** Expert witness in personal injury cases involving electric utility assets. Conducted technical investigations, reviewed and submitted discovery, and declarations to support evidentiary hearings and agreements.

Eugene L. Shlatz

Contractor – Contingent Worker

- **Duke Energy (Florida), Public Service of New Mexico & El Paso Electric.** Conducted studies to determine ancillary service requirements costs. Provided expert testimony ancillary service schedules to support OATT fillings before the U.S. Federal Energy Regulatory Commission.
- **Hydro Ottawa (Ontario).** Conducted an independent review of Hydro Ottawa's asset management and Distribution System Plan to support a rate request filing before the Ontario Energy Board (OEB). Provided recommendations to ensure compliance with OEB filing requirements for capital investments.
- **NorthWestern Energy (FERC).** Expert witness supporting ancillary services schedules and pricing for a filling before the U.S. Federal Energy Regulatory Commission.
- **NorthWestern Energy (Montana/FERC).** Expert witness for NEM Solar Integration and NERC Reliability Performance studies to comply with Montana Public Service Commission and U.S. Federal Energy Regulatory Commission requirements. Conducted technical and economic studies of solar impacts on NorthWestern's service territory and submitted expert testimony to support findings on ancillary services before the MPSC.
- **International Business Machines (IBM).** Conducted a reliability assessment of issues related to the City of Boulder, Colorado's application to the Colorado Public Utility Commission (PUC) to form a municipal electric utility. Conducted independent technical review of separation of electric assets and appeared as an expert witness before the CPSC on behalf of IBM.
- **Green Mountain Power (GMP).** Prepared independent testimony and appeared as an expert witness in a rate filing before the Vermont Public Service Commission (VPSC). Testimony supported capital investments for generation, transmission, distribution, IT/OT and physical assets.
- **NV Energy (Sierra Pacific Power Company).** Conducted a T&D avoided cost study to support an SPPC's rate filing and to determine Excess Energy Charges for net metering customers. Submitted expert testimony before the Nevada Commission on T&D marginal costs and application to NEM solar.
- **Toronto Hydro Electric System, Limited (THESL).** Prepared business case studies for major capital programs in rate filings before the Ontario Energy Board (OEB). Testified as an independent expert witness before the OEB on Distribution System Plans and renewable energy programs in Custom Incentive Rate (CIR) and Incremental Capital Module (ICM) filings.
- **Exelon (Philadelphia Electric Company).** Developed T&D avoided cost study to support PECO energy efficiency programs. Participated in a statewide stakeholder process to approve T&D avoided costs, which included the statewide EE program evaluator, the electric utility and related parties.
- **Puerto Rico Electric Power Authority (PREPA).** Conducted a T&D avoided cost analysis and prepared expert testimony to support PREPA's rate filing and avoided costs applied to net metering.
- **Public Utility Authority (Israel).** Conducted a technical and economic review of the Israeli Electric Corporation and Palestinian Electric Authority electric generation and power delivery system on behalf of the PUA. Assessed the adequacy of electric infrastructure, power costs and investment programs.
- **Vermont Department of Public Service (VDPS).** Conducted a geo-targeted analysis of energy efficiency programs designed to defer T&D investments. Worked with electric utility stakeholders to identify cost-effective deferral opportunities and to assess processes designed to target EE programs.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

- **Canadian Utility (Confidential) –** Confidential study to assess the value and strategic benefits of the acquisition of electric utility energy delivery assets. Included a technical and economic assessment of key regulatory and acquisition risk factors to support a recommendation.

- **Progress Energy.** Project manager of a best practices and compliance review of fixed asset charging practices. Reviewed methods, systems and practices used to record fixed assets for Florida and the Carolinas to support proposed changes filed with state commissions and the SEC.

- **Citizens Utilities/Vermont Electric Cooperative.** Supported numerous Certificate of Public Good (CPG) applications before the Vermont Public Service Board (VPSB). Expert witness for technical, environmental, and costing studies.

- **Vermont Department of Public Service (VDPS).** Conducted research and prepared sections of the Twenty-Year Electric Plan, including the impact of the independent system operator (ISO) and regional transmission organization (RTO) initiatives on Vermont's transmission providers.

- **Potomac Electric Power Company (PHI).** Project manager of a benchmarking study of storm hardening measures. Assessed the impact of hardening options on reliability and performance. Also assessed service quality (SQI) measures and performance-based rate (PBR) mechanisms.

- **Citizens Utilities (Vermont Electric Division).** Project manager for a T&D Audit mandated by the Vermont Public Service Board. Reviewed T&D plant accounting systems and processes, and provided recommendations for improvement.

- **Massachusetts Department of Telecommunications and Energy (MDTE).** Project manager of a stray voltage assessment of jurisdictional utilities. Identified causes of stray voltage and provided recommendations to mitigate future events, including action and improvement plans

Asset Management

- **Horizon Utilities Corporation.** Developed strategies and provided ongoing support for HU's asset management initiative. Conducted a gap analysis and implementation of asset management strategies and evaluation methods. Included an evaluation of infrastructure upgrades, operational and reliability improvement and implementation strategies using AM-based approaches.

- **First Energy**. Lead consultant of a project team that implemented asset management processes and capital prioritization models for 6 operating companies in three jurisdictions. Responsible for model development and applications, technical review and overall quality assurance.

- **Seattle City Light**. Conducted a benchmarking and gap analysis of the power supply and energy delivery business units. It included a business case analysis to support implementation of asset management methods and new AM organization.

- **Pepco/Conectiv (PHI)**. Responsible for an asset management and prioritization assessment of capital improvement and O&M programs for three states and the District of Columbia. It included developing asset prioritization methods for transmission, distribution and IT programs.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

» **Entergy**. Responsible for an asset management and prioritization assessment of Entergy's capital improvement programs for six jurisdictional utilities in 5 states. It included developing asset-specific prioritization methods for transmission and distribution programs.

» **PacifiCorp**. Responsible for an asset management and prioritization assessment of PacifiCorp's capital improvement programs for six jurisdictional utilities in 6 states. It included developing asset-specific prioritization methods for transmission and distribution and IT programs.

Work History

» Navigant Consulting, Director

» Stone & Webster Management Consultants, Executive Consultant

» Green Mountain Power Corp, Assistant Vice President, Energy Planning

» Ernst & Whinney, Supervisor

» Gilbert/Commonwealth, Senior Consulting Engineer

» Westinghouse Electric Corporation, Systems Analysis Engineer

» Boston Edison Company, Student Engineer, Cooperative Education Prog.

Certifications, Memberships, and Awards

» Professional Engineer - State of Vermont

» Institute of Electrical and Electronic Engineers, Section Chairman (Past)

Education

» M.S. Electric Power Engineering, Rensselaer Polytechnic Institute

» B.S. Electric Power Engineering, Rensselaer Polytechnic Institute

Articles, Publications and Course Instruction

» Grid Reliability and Resiliency Initiatives for the Island of Puerto Rico," Midwest Energy Solutions Conference, Chicago, February 2019.

» "Microgrid Development – Making it Work: ," Instructor: PowerGen Competitive Power College, Orlando, December 2016.

» "DG Proliferation Trends, Challenges and Solutions Addressing Interconnection Planning, Operations, Benefits & Cost Allocation," Instructor: DistribuTECH University, San Diego, Feb. 2015.

» "Smart Grid and Distributed Energy Storage," Total Energy USA, Houston Texas, November 2012.

» "Distributed Generation: Grid Impacts and Interconnection Strategies," Rocky Mountain Electric League, 2012 Spring Management, Engineering and Operations Conference, Omaha Nebraska.

» "Energy Storage Opportunities for Integration of Large-Scale Renewable Generation," Electricity Storage Association (ESA) Annual Conference, Washington DC, May 2012.

Guidehouse
Outwit *Complexity*

Eugene L. Shlatz

Contractor – Contingent Worker

- “Grid Integration of Renewable, Intermittent Resources,” 2011 PowerGen International Conference, December 2011, Las Vegas, NV, with Vladimir Chadliev.
- “Reducing T&D Investments Through Energy Efficiency” IEPEC, August 2011, with K. Parlin & W. Poor.
- “Value of Distributed Generation and Smart Grid Applications,” DistribuTECH, San Diego, Feb. 2011.
- “Prioritization Methods for Smart Grid Investments,” EEI Perspectives, April-May, 2010.
- “Evaluation of Targeted Demand-Side Management at ConEd (CECONY),” ACEEE Energy Efficiency Conference, September, 2009, with Craig McDonald.
- “DER Operational & Grid Benefits” Electric Light & Power, February, 2009.
- “Benefits of Smart Grid Integration with Distributed Energy Storage Systems,” Infocast Power Storage Conference, July, 2008.
- “The Rise of Distributed Energy Resources,” Public Utilities Fortnightly, Feb, 2007, with S. Tobias.
- “Risk Planning & Project Prioritization: Bringing Energy Delivery to the Next Level in Asset Management,” InfoCast T&D Asset Management Conference, St. Louis, MI, May 2004.
- “Valuation Methods: Estimating the Value of Avoiding the Risks Associated with T&D Reliability Failures,” EEI Spring 2004 T&D Conference, Charlotte, NC, April 2004.
- “Reliability Tradeoffs,” EEI Perspectives, January-February, 2004, with Daniel O’Neill.
- “What’s the Outlook for Distributed Generation Interconnection Standards?” 2003 PowerGen International Conference, Las Vegas, Nevada, December 2003.
- “Federal Interconnection Standards: Putting DG in a Box,” Public Utilities Fortnightly, April 2003, with Stan Blazewicz.
- “An Innovative Approach to Fact-Based Distribution Reliability Cost Optimization,” Distribution 2000, Brisbane, Australia, November 1999, with Cheryl Warren.
- “System Reliability: Competitive Issues,” Rethinking Electric Reliability Conf., Chicago Il, Sept 1997.
- “Reliability: Competition & Keeping the Lights On,” EUCI, Denver, Colorado, October 1998.
- “System Reliability in a Restructured Environment,” Electric System Reliability in a Competitive Environment Workshop, Denver, Colorado, October 1997.
- “Privatization Efforts in South America” EUCI Workshop, Denver, Colorado, January 1997.
- “Open Access Pricing Issues,” Transmission Pricing Conference, Vail, Colorado, Sept. 1996.

Guidehouse
Outwit *Complexity*

Eugene L. Shlatz

Contractor – Contingent Worker

Testimony and Appearances as an Expert Witness

Case Description	Company	Year	Docket	Jurisdiction
Rate Cases, Resource Planning, Open Access and Regulatory Investigations				
Wholesale Rate Filing (OATT)	Duke Energy	2020	ER20-919-000	FERC
Wholesale Rate Filing (OATT)	NorthWestern	2019	ER-1756-000	FERC
Retail Rate Filing (Net Metering)	NorthWestern	2018	D2018.2.12	Montana
Request for Increase in Retail Rates	GMP	2017	17-3112	Vermont
Transfer of Electric Assets (Municipalization)	IBM	2017	15A-0589E	Colorado
Marginal Cost Study (NEM & Rate Filing)	NV Energy	2016	16-06006	Nevada
Custom Incentive Rate Filing	Toronto Hydro	2016	EB -2014-0116	Ontario
Incremental Capital Module (Rate Filing)	Toronto Hydro	2014	EB-2012-0064	Ontario
Summer/Winter 2011 Storm Review	Exelon/ComEd	2013	11-0588	Illinois
Distributed Generation Integration	NV Energy	2012	10-04008	Nevada
Distributed Utility Planning	CUC	2011	6290	Vermont
Power Purchase Contracts – IURC Complaint	Jay REMC	2003	9704-CP-069	Indiana
Section 205 Filing – Wholesale Rates	NISource	1998	ER96-35-000	FERC
Open Access Transmission Tariff Filing	NISource	1997	ER96-399-000	FERC
Request for Increase in Wholesale Rates	NISource	1996	ER92-330-000	FERC
Request for Increase in Retail Rates	GMP	1996	5532	Vermont
Least-Cost Planning Integrated Resource Plan	GMP	1991	5270	Vermont
Request for Increase in Retail Rates	GMP	1991	5428	Vermont
Request for Increase in Retail Rates	GMP	1990	5370	Vermont
Request for Increase in Retail Rates	GMP	1989	5282	Vermont
Request for Increase in Retail Rates	GMP	1988	5125	Vermont
Certificates of Public Good				
Transmission Line Construction Authorization	SSVEC	2010	E-01575A	Arizona
Northern Loop Transmission Upgrades	Velco/CUC	2004	6792	Vermont
Substation Reconstruction – Richford	CUC	2003	6682	Vermont
Island Pond to Bloomfield Line	CUC	2001	6044	Vermont
HK Webster Substation	CUC	1999	6045	Vermont
Burton Hill Substation	CUC	1999	6046	Vermont
Border to Richford 120/46kV Line	CUC	1998	5331A	Vermont
New Transmission Lines and Substation	IBM	1991	5549	Vermont
New Substation – Northern Vermont	GMP	1990	5459	Vermont
Gas Turbine Interconnection Facilities	IBM	1989	5347	Vermont
Dover Substation Expansion	GMP	1987	5226	Vermont
Industry Restructuring & Asset Transactions				
Purchase of Electric Assets	VEC	2004	6853	Vermont
Certificate of Consent, Sale of Distribution Assets	CUC	2004	6850	Vermont
Certificate of Consent, Sale of Transmission Assets	Velco/CUC	2004	6825	Vermont
Prudency Review and Audit Support	CUC	2003	5841/5859	Vermont
Competitive Opportunities Filing	ConEdison	1997	96-E-0897	New York

Guidehouse

KENTUCKY POWER
An AEP Company

Independent Review of Reliability Performance

&

Distribution System Investments

November 6, 2023

Independent Review & Assessment

Distribution Reliability Performance and Investments

Table of Contents

List of Figures

List of Tables

Executive Summary

Guidehouse was engaged by Kentucky Power Company (Kentucky Power) to perform a detailed review of Kentucky Power's reliability performance and investments in its distribution system in response to issues raised in its current rate filing.[1] From its detailed review and analysis of data covering the period 2008 to the present, industry benchmark data for utilities with comparable service territories and distribution systems, and interviews with Kentucky Power, Guidehouse offers the following findings and conclusions.

Kentucky Power's,

- Distribution system is located in a region with among the highest tree coverage and density for the peer group of electric utilities, with low customer density and high average circuit length, each of which are contributing factors to reliability performance;
- Reliability performance as measured by System Average Interruption Frequency Index (SAIFI) is within the peer group average. Reliability performance as measured by System Average Interruption Duration Index (SAIDI) is slightly above the peer group average;
- Tree-related customer interruptions from outside the right-of-way (TOR) is the leading cause of outages. Kentucky Power proposes to reduce TOR interruptions via incremental investments under its proposed Distribution Reliability Rider (DRR);
- Spending on capital projects and maintenance is at or above the peer group average, which is notable for a utility that has experienced a decrease in customers and demand;
- Vegetation management practices are at or above industry practices, with trimming completed on schedule and clearances based on species type and location;
- Equipment failures are the second leading cause of customer interruptions. Proactive efforts to reduce customer interruptions via replacement of equipment with high failure rates (such as cutouts and insulators) are underway. Kentucky Power proposes to expand its ongoing replacement program through incremental investments under the proposed DRR;
- Capital spending on distribution assets as measured by total distribution investments and number of customers is at or above industry averages, which is notable as Kentucky Power has experienced a decline in load growth and number of customers served;
- Spending on distribution maintenance as measured by distribution line miles and number of customers is at or above industry averages;
- Equipment maintenance practices, procedures and inspection intervals is consistent with industry practices, with inspection cycles completed on time;
- Emergency restoration procedures, which include a centralized Incident Command structure, are consistent with industry practices; and
- Storm restoration intervals as measured by customers restored over storm duration, and restoration costs are within industry averages for most types of storms (e.g., wind and snow), except ice storms where costs are higher due to tree density and storm severity.

[1] Case No. 2023-00159.

1. Introduction

1.1 Background

Kentucky Power engaged Guidehouse (consulting) to perform a detailed review of Kentucky Power's reliability performance and investments in its distribution system in response to issues raised in its current rate filing.[2] Guidehouse's review sought to determine if Kentucky Power's distribution operations, maintenance, and storm restoration processes and investments are consistent with practices of electric utilities with comparable service territories and distribution systems. In addition, Kentucky Power requested Guidehouse to perform a review of their planning and capital investment process to determine if they are appropriate and consistent with good utility practice.

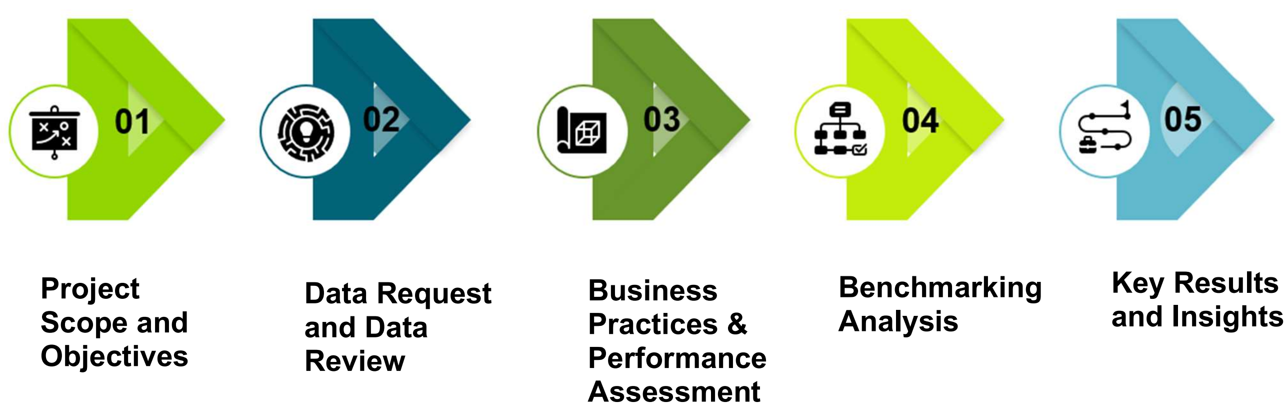
Guidehouse's review and assessment of Kentucky Power included on-site field visits, a series of interviews with Kentucky Power personnel, a comprehensive review and assessment of performance and costs, and an in-depth comparison review of utility practices spanning a range of reliability performance, investment levels and operations. A key element of Guidehouse's review included benchmarking Kentucky Power's reliability performance to other distribution utilities with comparable territory attributes.

This report highlights the key findings of the analysis and provides insights from Guidehouse's subject matter experts who have reviewed, in depth, information provided by Kentucky Power.

1.2 Guidehouse Scope of Work and Approach

The analysis was focused on Kentucky Power's distribution system. Transmission practices are outside of the scope of work. Guidehouse used a 5-step approach to assess Kentucky Power's system reliability, operating/maintenance practices and investments as shown in Figure 1.

Figure 1. Guidehouse Approach



Guidehouse's review and assessment included an analysis of Kentucky Power's planning and design, investment levels and reliability performance outlined in Table 1. Guidehouse requested

[2] Case No. 2023-00159

data from Kentucky Power in each these areas for up to 15 years and benchmarked key metrics to those of other electric utilities with comparable service territories.

Table 1. Topics Addressed and Analyzed

Topics Assessed	Description
Benchmarking	Reliability metrics (SAIDI, SAIFI, CMI[3]), spending (capital & O&M)
Economic Growth	Historical and forecasted load and customer growth / contraction
Vegetation Management	Distribution vegetation standard, planned and completed work
Distribution Capacity Plans	Substation and feeder: line capacity, peak load, forecast, historical investments
Maintenance	Substation and distribution maintenance planned and completed
Engineering Standards	Distribution planning and design, and loading practices
Reliability Programs	Description and investment level of each reliability program
Grid Modernization	Description of program, planned and actual spending per year
Emergency Response	Incident Command Structure, mutual aid, pre-planning
Storm Restoration	Customer restoration times and costs

[3] Customer Minutes of Interruption.

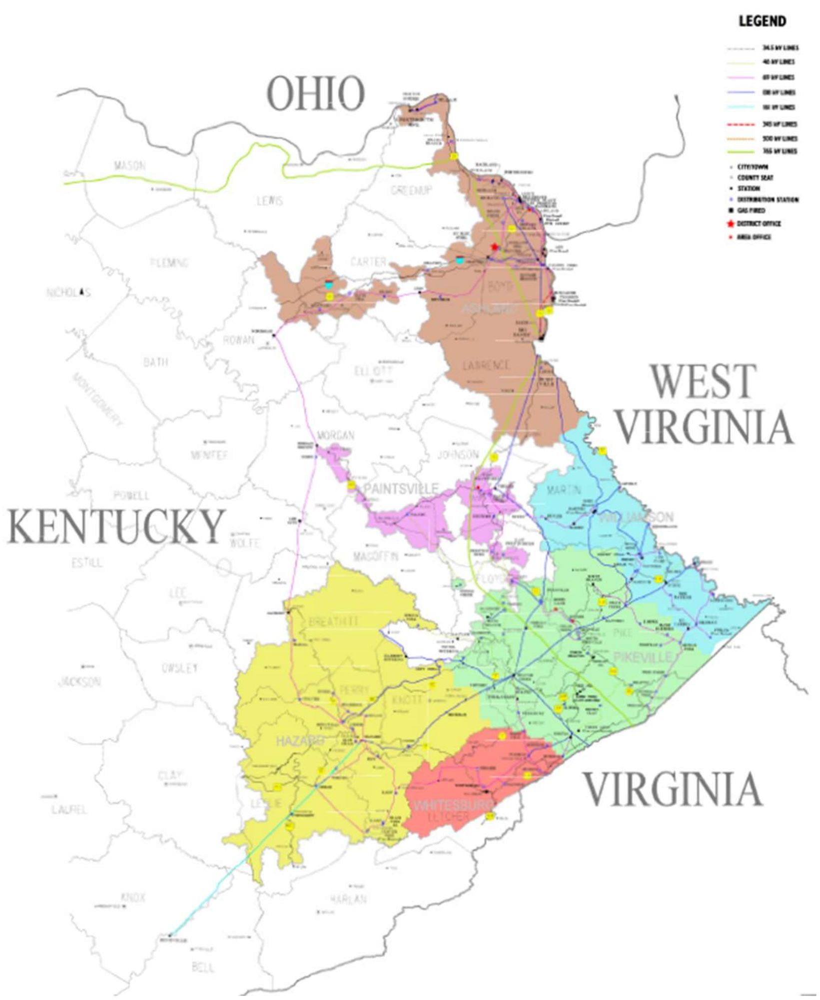
2. Key Findings and Insights

2.1 Overview

The following sections document Guidehouse's key findings and insights on Kentucky Power's reliability, spending, planning, engineering design standards and maintenance practices. It includes benchmarking Kentucky Power's current and past practices with utilities with comparable distribution system attributes and topography. Guidehouse's benchmarking analysis focused on the past five to ten years, as data typically was available during these years.

Figure 2 presents Kentucky Power's service territory boundaries and operating areas. A significant portion of Kentucky Power's service territory is located in heavily forested rural areas of Kentucky, which constitutes an important aspect of our review, as it includes benchmarking Kentucky Power's reliability performance, spending levels and maintenance practices with those of other utilities with similar distribution systems.

Figure 2. Kentucky Power Service Territory[4]



[4] Six districts are highlighted that correspond to areas tracked in Kentucky Power's Outage Management System.

2.2 Industry Benchmarking

To evaluate Kentucky Power's reliability and spending using comparable benchmarks, Guidehouse selected a peer group of electric utilities with similar distribution system attributes, including number of customers, topography, and percent vegetation.

Peer Group Selection

Guidehouse applied a five-step elimination process to select a peer utility group for benchmarking Kentucky Power's reliability performance and costs with those of utilities with comparable service territories. Because of the high percentage of interruptions caused by trees, Guidehouse selected utilities located in states with rural load and extensive tree coverage for peer group benchmarking. Sixty-one utilities were identified as candidates for benchmarking; each are listed in the Appendix. Of these 61 utilities, twenty-one, including Kentucky Power, were chosen for the peer utility group. The steps that Guidehouse followed to select the peer group are outlined below.

- **Criteria 1**: Collect data for all utilities in four states with the highest percentage of forested areas and that are comparable to Kentucky, and that report reliability indices)[5]
- **Criteria 2**: Remove 19 municipal utilities as they typically have smaller service areas and shorter distribution lines
- **Criteria 3**: Remove four other utilities that serve large urban areas
- **Criteria 4**: Remove 15 utilities with tree coverage below 85%
- **Criteria 5**: Remove two utilities that serve less than 10,000 customers

As noted above, the selection process produced a peer group of 21 electric utilities. A key feature of the peer group selection process was the determination of distribution circuit tree coverage. Unlike statewide tree coverage that is based on percent forested, tree coverage in Criteria 4 is based on data collected for the specific service territories of each of the peer group utilities.[6] Guidehouse obtained the data from publicly available sources and the consulting firm First Quartile.[7] Notably, Kentucky Power is among the highest in the peer group, with 99 percent tree coverage.

Table 2 presents the final peer group, of which 9 are investor-owned Utilities (IOUs) and 12 rural electric cooperatives (RECs); the latter of which serve customers located in rural areas with

[5] Includes Maine (ME), New Hampshire (NH), West Virginia (WV), Vermont (VT).

[6] The tree coverage for Kentucky Power and the peer group is high as the analysis assumes that any trees located within a defined "cell block" constitutes 100 percent coverage.

[7] The analysis is based on original research conducted by the U.S. Department of Agriculture. Results are derived via an imaging analysis of 240 by 240 meter "grid cells" including those located within the peer group service territories. Each cell with one of more trees within the cell is assigned as a block with tree coverage. Source: Krist, Frank J., Jr.; Ellenwood, James R.; Woods, Meghan E.; McMahan, Andrew J.; Cowardin, John P.; Ryerson, Daniel E.; Sapio, Frank J.; Zweifler, Mark O. 2014. 2013-2027 National Insect and Disease Forest Risk Assessment. FHTET-14-01. Fort Collins, Colorado: U.S. Department of Agriculture, Forest Service, Forest Health Technology Enterprise Team.

substantial tree coverage. The 21 peer group utilities are benchmarked for reliability as measured by the IEEE P1366 guidelines and for costs. Only the IOUs within the peer group are benchmarked for cost using FERC Form 1 data, as the RECs typically do not report costs via publicly available sources. Further, benchmark data and sources for maintenance practices, storm restoration intervals and storm restoration costs in subsequent sections were obtained from a different set of electric utilities (*i.e.,* outside the peer group) provided by First Quartile Consulting.

Table 2. Industry Benchmarking Peer Group

Utility	Type (IOU or REC)	State	Customer Count[8]	Service Territory Tree Coverage[9]
Kentucky Power	IOU	KY	166,243	99%
Central Maine Power Co	IOU	ME	634,601	95%
Duke Energy Kentucky	IOU	KY	142,504	89%
Green Mountain Power Corp	IOU	VT	264,575	94%
Liberty Utilities (Granite State)	IOU	NH	44,932	98%
Monongahela Power Co	IOU	WV	388,333	98%
Public Service Co of NH	IOU	NH	521,953	88%
The Potomac Edison Company	IOU	WV	204,050	98%
Versant Power (former Emera)	IOU	ME	164,510	96%
Big Sandy Rural Elec Coop Corp	REC	KY	12,778	100%
Cumberland Valley Electric, Inc.	REC	KY	23,831	98%
Eastern Maine Electric Coop	REC	ME	12,708	96%
Grayson Rural Electric Coop Corp	REC	KY	14,813	98%
Jackson Energy Coop Corp (KY)	REC	KY	51,119	96%
Licking Valley Rural Elec Coop	REC	KY	17,327	99%
New Hampshire Elec Coop Inc	REC	NH	81,297	97%
Owen Electric Coop Inc	REC	KY	61,365	91%
South Kentucky Rural Elec Coop	REC	KY	68,891	89%
Taylor County Rural Elec Coop	REC	KY	26,663	85%
Tri-County Elec Member Corp (TN)	REC	KY	26,261	90%
Vermont Electric Cooperative, Inc	REC	VT	38,992	90%

Distribution Spending - Capital

Guidehouse obtained FERC Form 1 data for each of the IOUs to compare total capital spending for distribution versus Kentucky Power for the last 15 years.[10] The RECs are excluded as investment data typically is not publicly available from REC web sites and published reports. Figure 3 and Figure 4 presents Kentucky Power's capital spending for distribution assets versus the IOU peer group. The tables present average 15-year spending by Kentucky Power versus the IOU peer group for both total original plant balances and number of customers served. Two

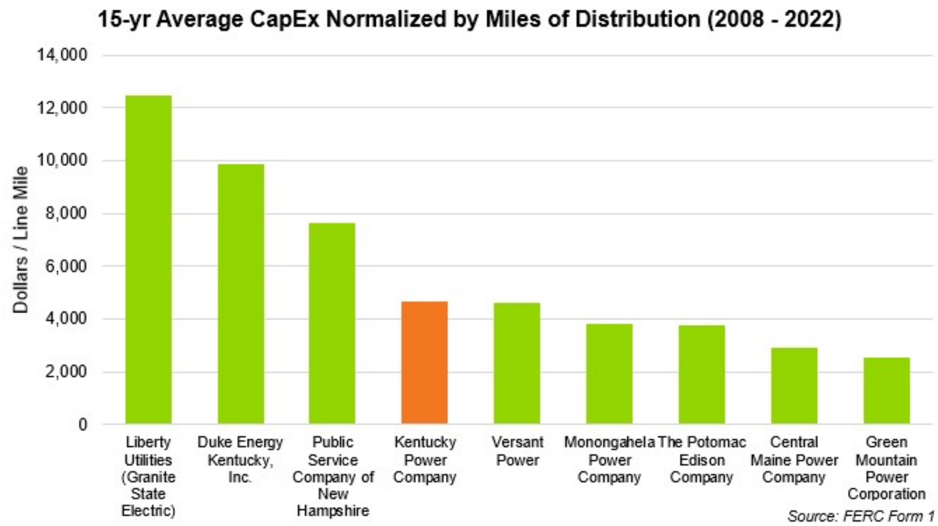
[8] Ten-year average (2013-2022). Calculated using customer data from the U.S. Energy Information Administration. Source: Annual Electric Power Industry Report, Form EIA-861 detailed data files

[9] Percent tree coverage based on utility service territory DATA. Guidehouse obtained the data from the consulting firm First Quartile (see additional information under Criteria 4).

[10] FERC accounts 360 through 374.

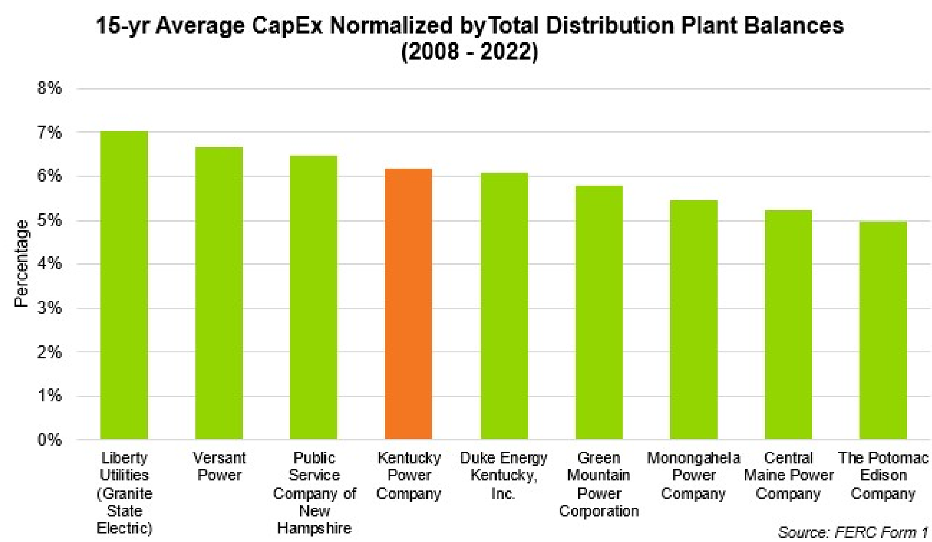
normalizing factors were chosen to compare Kentucky Power's spending on capital to the peer group average for a range of benchmarks.

Figure 3. Kentucky Power Versus IOU Peer Group Capital Spending (by Distribution Circuit Miles)



Results indicate Kentucky Power's capital spending for distribution assets as a function of total original plant balances or distribution line miles is within or above the IOU peer utility group average spending on capital projects.

Figure 4. Kentucky Power Versus IOU Peer Group Capital Spending (by Original Plant Balances)

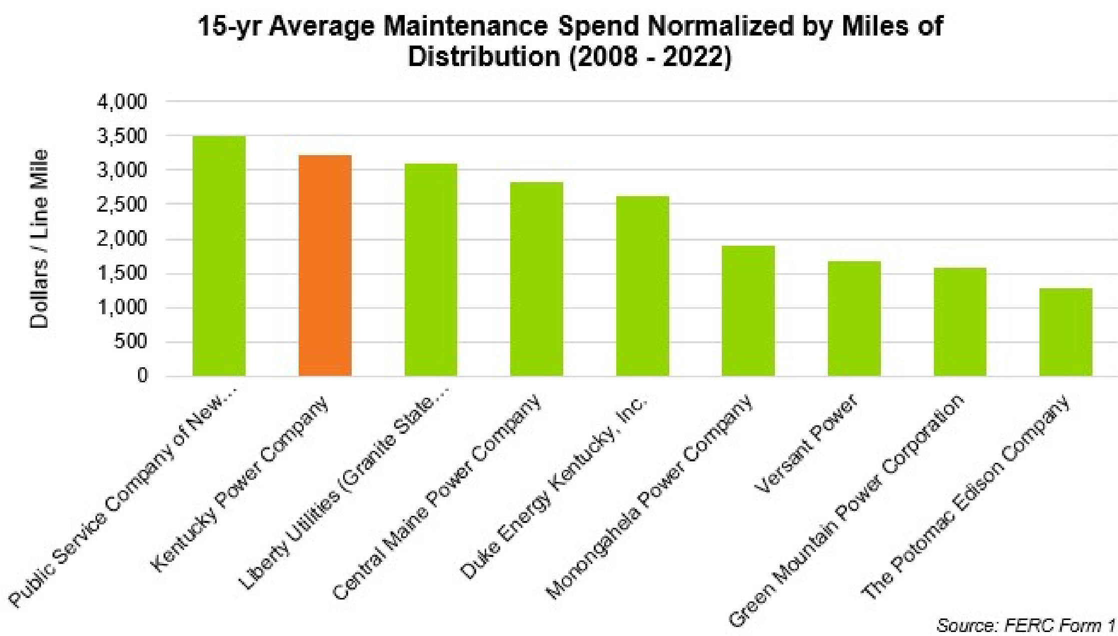


Guidehouse recognizes that benchmark results for the peer utility group likely includes spending for new customer connections and distribution lines needed to accommodate the load growth. Hence, the normalized values for Kentucky Power likely are understated as the number of customers and peak demand in its service territory has declined over the past 10 years.

Distribution Spending – Maintenance

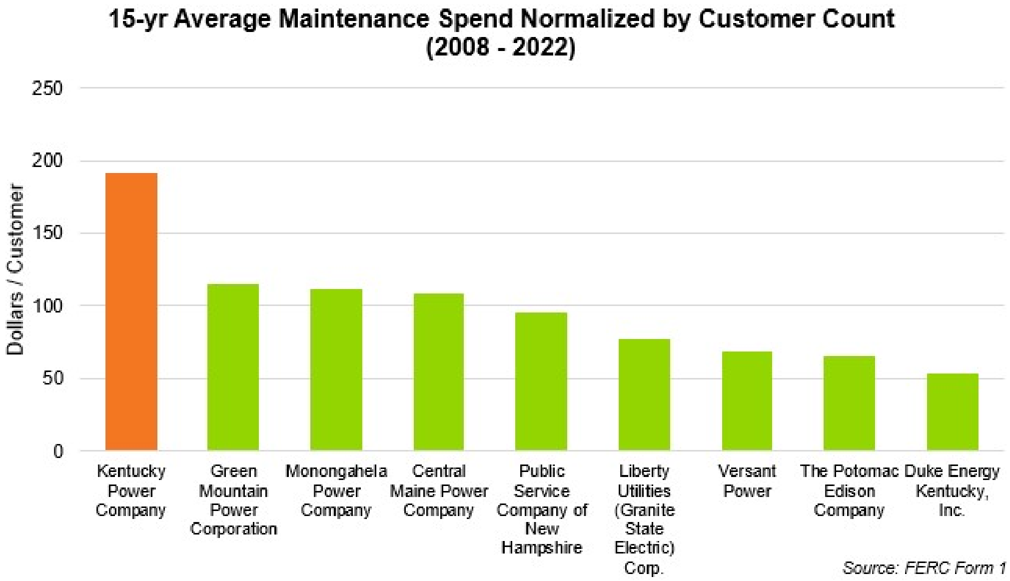
Similar to capital investments, Guidehouse obtained FERC Form 1 data for each of the IOUs to compare total distribution operation and maintenance (O&M) spending versus Kentucky Power for the last 10 years. The RECs are excluded as expense data typically is not publicly available. Figure 5 and Figure 6 present Kentucky Power's maintenance spending for distribution versus the IOU peer group for both the number of customers served and distribution line miles. Two normalizing factors were chosen to compare Kentucky Power's spending for maintenance to the peer group average for a range of benchmarks.

Figure 5. Kentucky Power Versus IOU Peer Group Maintenance Spending (by Distribution Circuit Miles)



Results indicate Kentucky Power's maintenance expenses for distribution assets as a function of total line miles substantially exceeds the peer group average. Guidehouse attributes the higher amount of maintenance expense for Kentucky Power to the high cost assigned to the Overhead Lines account in the FERC Form 1 for distribution. The Overhead Lines account represents a large majority of maintenance expense for Kentucky Power and most of these expenses are for vegetation management, which is higher than the peer group average due to the very high tree density along its distribution circuit rights-of-way (ROW).

Figure 6. Kentucky Power Versus IOU Peer Group Maintenance Spending (Total Customers)



Similar to results obtained for line miles, Kentucky Power's maintenance expenses for distribution as a function of total customers is well above the IOU peer group average.

Reliability and Resilience

Guidehouse also conducted benchmarking of reliability performance of the entire peer group for both Major Event Day (MED) and non-MED statistics.[11] Figure 7indicates Kentucky Power's reliability indices for SAIFI is within peer group averages while Figure 8 indicates SAIDI is above the peer group average without MED. Figure 10 indicate SAIDI with MEDs is closer to the peer group average, most likely due to robust fault isolation and hardening measures undertaken by Kentucky Power. Accordingly, Guidehouse concludes Kentucky Power's reliability performance as measured by the number of customer interruptions is on par with peer group benchmarks, and the higher SAIDI levels are due to longer restore times due to crew travel to locate and repair outages (Table 6 confirms Kentucky Power's distribution circuits are long, particularly 34.5kV lines which average over 50 miles.)

Guidehouse notes that the comparison of Kentucky Power reliability indices to the peer group may not be entirely comparable to the peer group, as Kentucky Power's indices include planned interruptions, whereas many utilities exclude planned interruption from reported reliability indices, consistent with IEEE P1366 recommended practices. **When planned interruptions are excluded, Kentucky Power's reliability indices for both SAIFI and SAIDI are closer to peer group averages**.[12]

[11] Kentucky Power applies IEEE Standard 1366-2017 to derive MED and non-MED reliability indices. MED are derived to identify events caused by storms or other conditions causing a large number of customer interruptions.
[12] Planned interruptions for Kentucky Power are about 15 and 11 percent of non-MED CI and CMI, respectively, over the past five years.

Figure 7. Kentucky Power Versus Peer Group Reliability without MED (SAIFI)

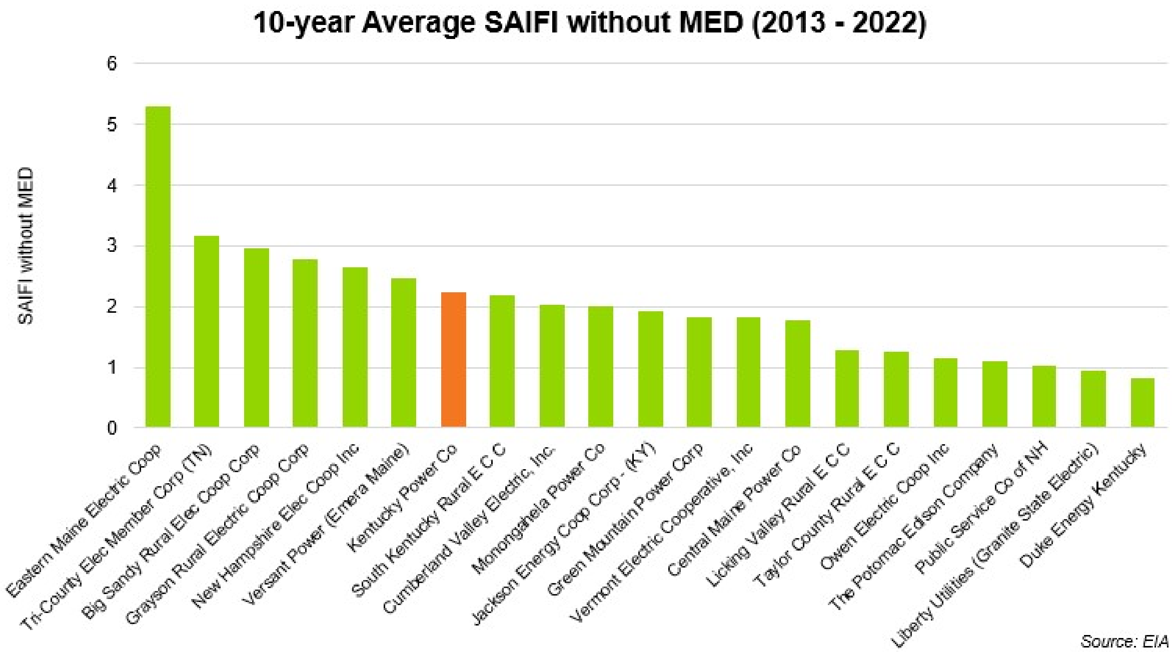


Figure 8. Kentucky Power Versus Peer Group Reliability without MED (SAIDI)

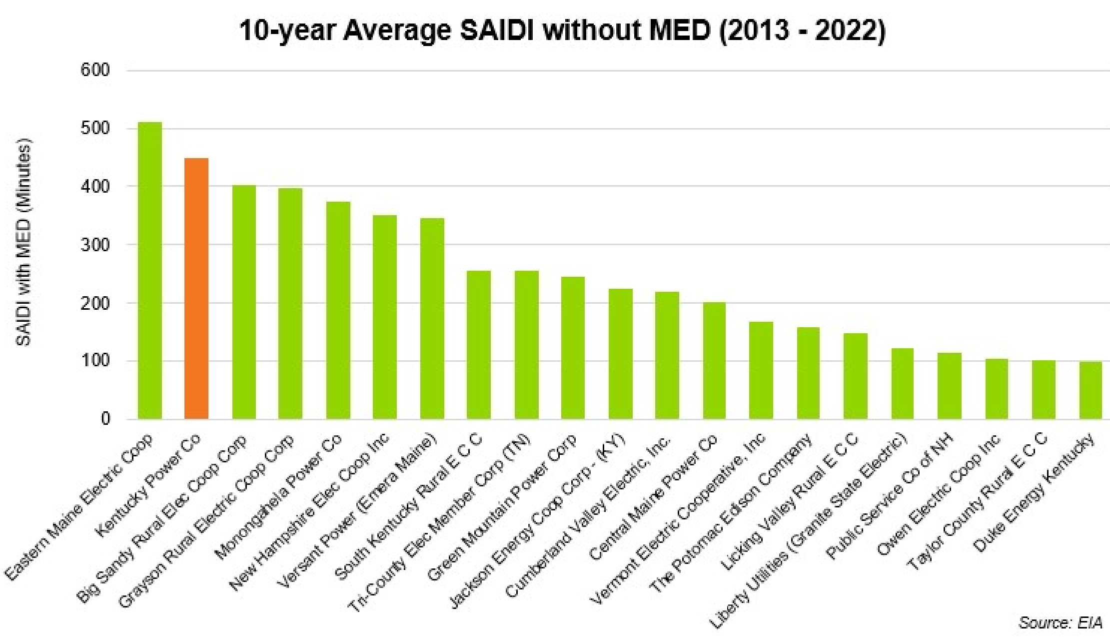


Figure 9. Kentucky Power Versus Peer Group Reliability with MED (SAIFI)

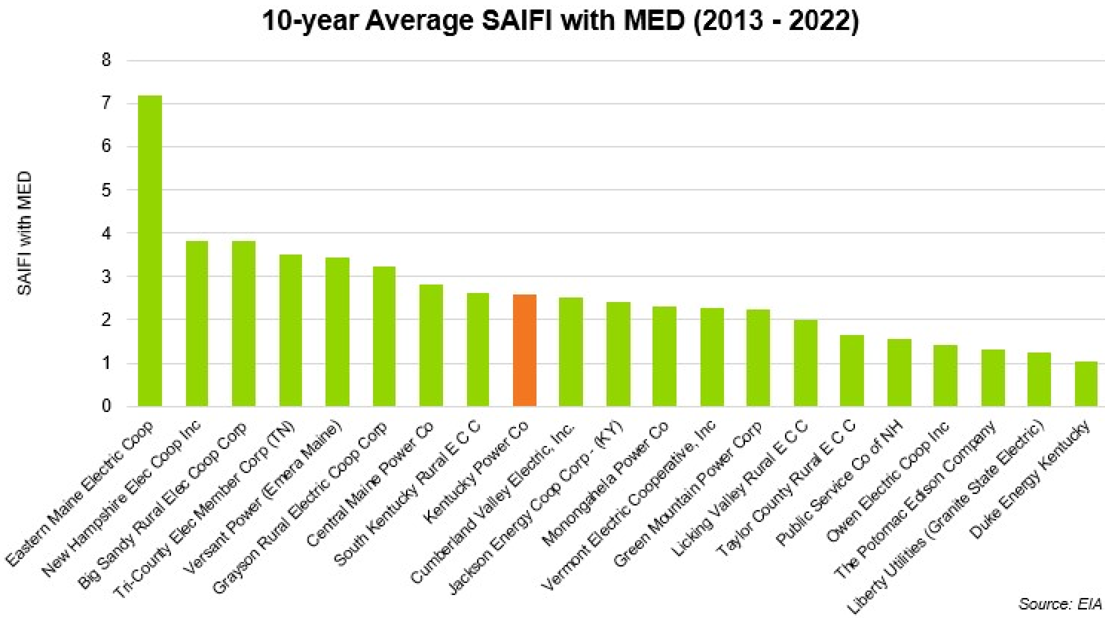


Figure 10. Kentucky Power Versus Peer Group Reliability with MED (SAIDI)

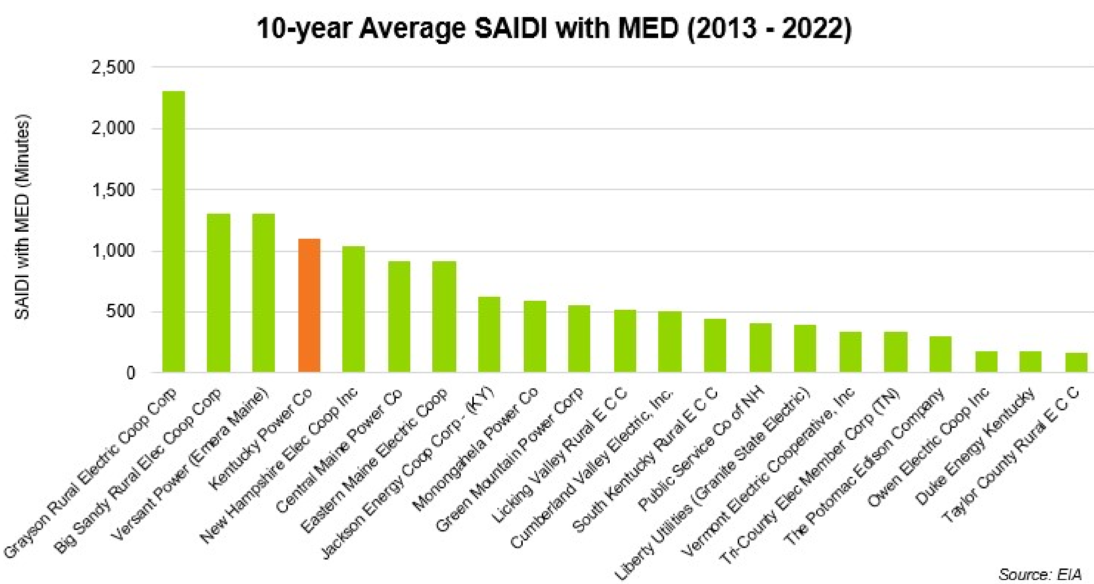
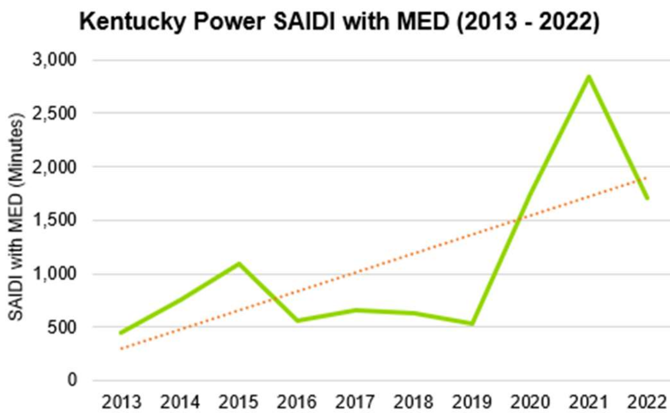


Figure 11 presents Kentucky Power's reliability performance as measured by SAIDI with MEDs annually over the past 10 years. The trendline in the chart indicates that although Kentucky Power's SAIDI during major storm events is closer to the peer group average, indices have trended upward over the past five years. The upward trend confirms that Kentucky Power's proposed spending via the DRR is needed to bring SAIDI to lower levels, particularly for the TOR program which is a primary contributor to SAIDI during major storms.

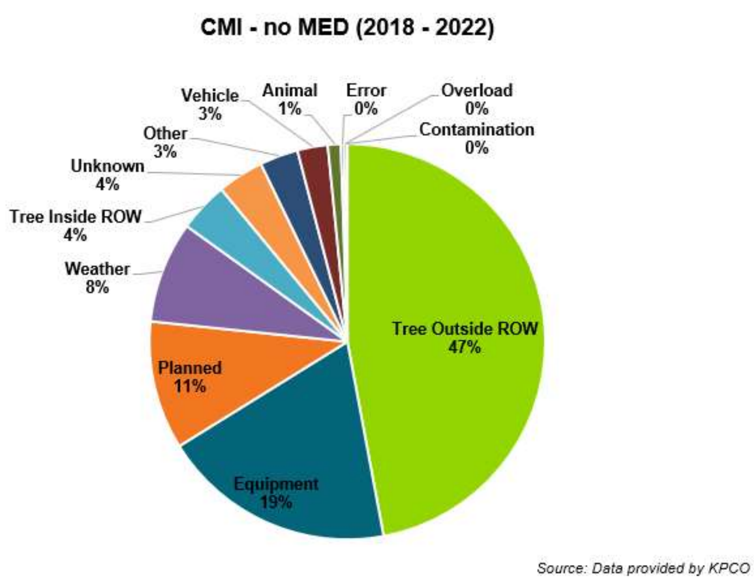
Figure 11. 10-Year SAIDI with MEDs (with Trendline)



Source: EIA

Figure 12 presents Kentucky Power reliability indices over the past five years by cause code. Vegetation Management (VM) in the form of tree contact – Trees in the ROW (TIR) and Trees out of the ROW and weather are the dominant cause codes for both MED and non-MED, distantly followed by equipment failure. The dominance of trees as a cause of outages underscores Kentucky Power's prior and forward-looking focus on mitigating tree relate outages to improve reliability performance. Additional details on VM practices appear in Section 2.3.

Figure 12. Reliability Indices by Cause Code including MEDs[13]



Source: Data provided by KPCO

---

[13] Guidehouse notes that the derivation of MED events is based on the use of a logarithmic function to differentiate normal versus MED events. Given the number and severity of storms Kentucky Power has encountered during some years {e.g., 2021 and 2022}, the MED threshold likely is higher in these years, which would place a higher number of interruptions into the non-MED category. The outcome of this premise is an increase in non-MED SAIDI and SAIFI during years with high storm activity compared to other utilities that have not experienced the same number or severity of storms.

Table 3 lists the equipment impacted under the equipment cause code (19 percent of all causes) for SAIDI and SAIFI over the past five years. Fused cutouts and insulators are the primary equipment contributing to reliability under the equipment cause code, which underscores Kentucky Power's focus on prioritizing replacing equipment most prone to failure over the past several years and as proposed in its Distribution Reliability Rider (DRR) program.[14] Additional details are presented in Section 2.4.

Table 3. Equipment Cause Code Details

Equipment Description	Sum of CMI (2018 – 2022)	Sum of CMI (MED) (2018 – 2022)	Sum of CMI (non-MED) (2018 – 2022)	Total Number of Failures (2018 – 2022)	Number of Failures (MED) (2018 – 2022)	Number of Failures (non-MED) (2018 – 2022)
Cutout	14,313,832	2,490,630	11,823,202	2743	85	2658
Insulator[15]	13,889,398	93,853	13,795,545	282	5	277
Pole	9,391,038	2,777,772	6,613,266	196	17	179
Other Equipment	8,946,833	4,683,361	4,263,472	196	13	183
OH Conductor	8,349,009	1,517,504	6,831,505	728	37	691
Crossarm	5,876,413	826,861	5,049,552	103	4	99
Transformer (Line)	4,898,864	504,968	4,393,896	930	34	896
Connector / Clamp	4,347,057	304,905	4,042,152	1133	35	1098
Arrester	4,248,768	114,651	4,134,117	244	3	241
Recloser	2,107,196	631,432	1,475,764	38	3	35
Regulator	2,054,652	987,636	1,067,016	26	4	22
Jumper / Riser	1,964,752	61,554	1,903,198	111	3	108
Splice	1,637,811	122,704	1,515,107	250	11	239
OH Switch	1,271,088	0	1,271,088	33	0	33
Fuse	990,270	430,310	559,960	743	16	727
UG Conductor	692,700	88,178	604,522	171	4	167
Relay	644,255	0	644,255	2	0	2

Values presented in Table 3 confirm that Kentucky Power is proposing to allocate spending in the DRR (under Asset Renewal / Storm Hardening) on equipment most susceptible to failure and to equipment that contributes to customer interruption minutes under the equipment cause code – cutouts and insulators are the highest causes of interruptions per customer minute.[16] Guidehouse expects the proposed increase in spending, prioritized for key equipment categories, proposed in the DRR will improve reliability performance along with other measures outlined in the DRR.

> ***Summary Assessment:*** *Kentucky Power's reliability performance and spending is comparable to electric utilities with similar distribution system circuits and locational attributes. Kentucky Power's reliability performance is within the peer group for SAIFI and above the peer group for SAIDI based on metrics reported over the past 5 years. When Kentucky Power's reliability indices are adjusted to exclude planned interruptions, the indices are within or closer to the peer group values. Guidehouse attributes Kentucky*

[14] Kentucky Power describes the proposed DRR as a Work Plan that targets on a programmatic basis, incremental investments for reliability improvements to supplement work completed under base rates. If approved, it will enable Kentucky Power to complete incremental work on a faster timeline and proactively address major outages

[15] Insulators that are not part of the cutout assembly (e.g., post insulators)

[16] Kentucky Power reports that it will monitor and track defective equipment in its the Asset Renewal/Storm Hardening or Resiliency program component of the DRR.

Power's higher SAIDI to the longer average distribution feeder length, particularly on those rated 34.5kV, which require longer crew times to patrol, locate and repair affected line segments. Further, circuits rated 34.5kV are more susceptible to interruptions, which further contributes to Kentucky Power's higher reliability indices.

The greatest percentage of Kentucky Power's interruptions are caused by tree contact, both from within and outside of ROWs, followed by equipment failures, and spending for each cause code has appropriately focused on mitigating interruptions within these causes. Kentucky Power's capital spend on distribution is also consistent with industry benchmarks, which is notable for a utility that has experienced a reduction in the number of customers and electric demand over the past 10 years.

2.3 Vegetation Management

Reliability indices presented in the prior section confirm that trees, both within and outside the ROW, is the dominant cause of interruptions for both MED and non-MED events. Guidehouse's review and assessment of Kentucky Power's VM program addresses the following topics and questions.

- Are Kentucky Power's VM guidelines and clearing practices consistent with good utility practice and in alignment with the benchmark group?
- Has Kentucky Power completed VM maintenance activities consistently on cycle?
- What percent of the interruptions are caused by TIR and TOR? Has the percentage of outages due to trees outside of ROW increased over the past 5 years?
- Are there interim VM activities for hot spots? How does Kentucky Power address problematic circuits via off-cycle trimming?
- How does Kentucky Power VM reliability performance compare to the peer group benchmark; that is, utilities with service territories in rural, high density treed areas?

Forestry Management Standards and Benchmark Performance

Kentucky Power's VM standard is outlined in AEP's *Forestry Management Guidelines*.[17] The guidelines apply to transmission lines and primary and secondary distribution lines.[18] The guidelines include a comprehensive set of clearance requirements and practices for forestry activities covering contractor performance, clearing practices for different species and tree location, danger and hazard trees, customer and public notifications, and data collection. Section 6 addresses specific requirements for distribution primary and secondary clearing. Guidehouse's review of the guidelines confirms that Kentucky Power's VM activities, as outlined in the document, are consistent with good utility practice.

[17] AEP Forestry: Vegetation Management Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance Operations.

[18] The VM Guidelines exclude tree trimming or removal for the customer service drop, which are the responsibility of the customer.

Kentucky Power conducts tree clearing on its distribution system on a 5-year cycle. Figure 13 presents trim cycles for rural segments of distribution systems for the benchmark group of utilities .[19] Results confirm that Kentucky Power's trimming cycle is within industry averages.

Figure 13. Trim Cycle for Rural Line Segments (IOUs)

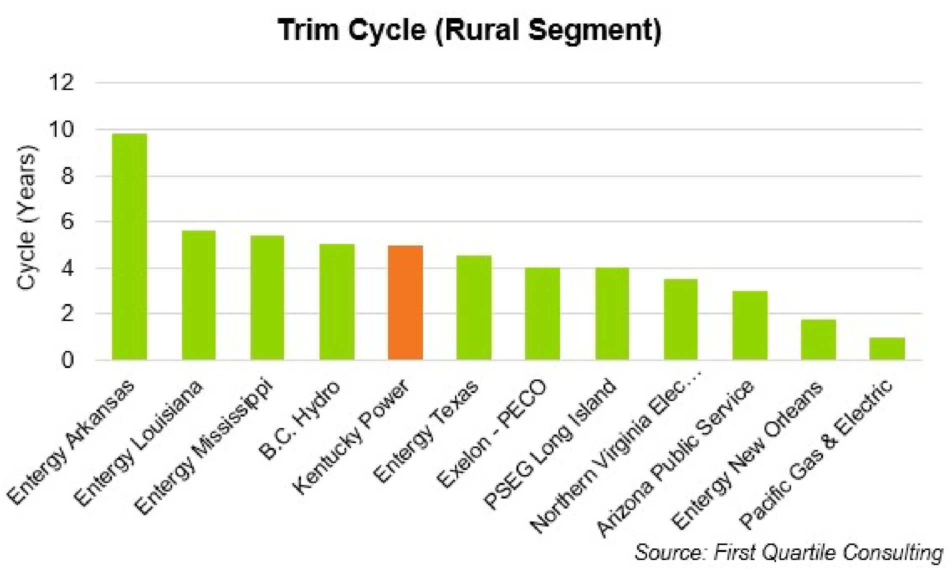


Figure 14 confirms that Kentucky Power's VM program achieved its trimming schedule over the past five years, with minimal variance between targeted and completed miles.

Figure 14. Kentucky Power 5-Year Tree Clearing Cycle

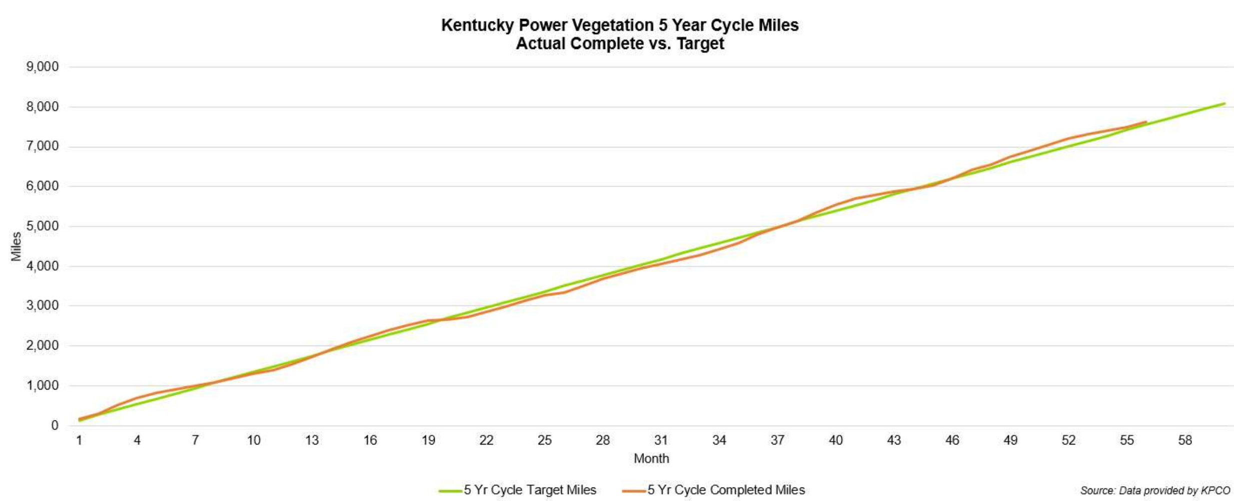
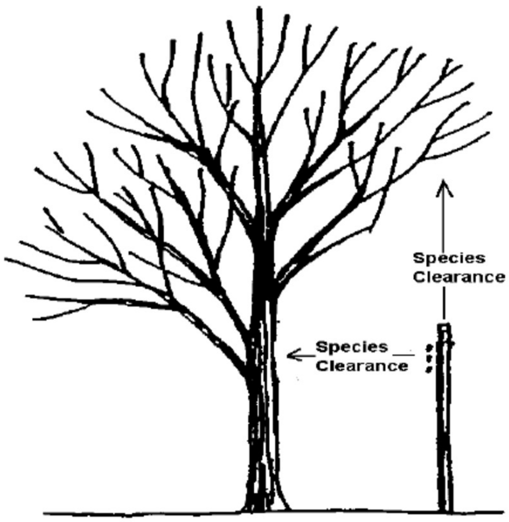


Figure 15 presents Kentucky Power's tree clearance guidelines for species located within the ROW. It highlights the clearance envelope for overhang and side clearances from primary

[19] Benchmark group provided by 1st Quartile Consulting. Values exclude the urban segment of each utility, where applicable.

conductors required for Kentucky Power's 5-year trimming cycle. These clearances meet or exceed industry practices based on Guidehouse's VM experience at other electric utilities.

Figure 15. Kentucky Power Distribution Clearance Guidelines[20]



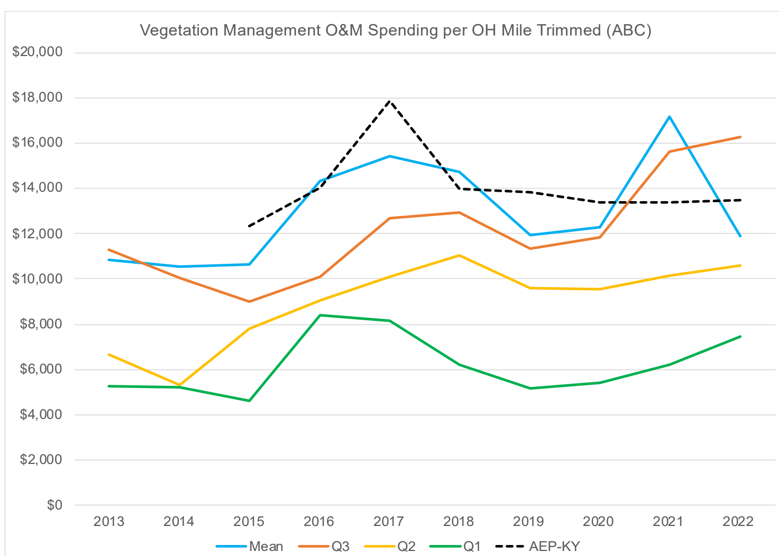
Minimum Clearances by Species:

- Fast Growing – 20 ft
- Medium Growing – 15 ft
- Slow Growing – 10 ft

Reliability Performance and Industry Benchmarks

Figure 16 presents Kentucky Power's spending on vegetation management per mile of line versus industry benchmarks over the last 10 years. Results indicate the percentage of tree-related interruptions for Kentucky Power is above the industry benchmark. The much higher level of interruptions as measured by CMI further supports Kentucky Power's TOR component of its proposed DRR described in the following subsection.

Figure 16. Kentucky Power VM Reliability Performance Versus Industry Benchmark Group



Source: First Quartile Consulting and KPCO

[20] FOD_025_Forestry_Clearing_and_Operating_Guidelines_Rev_6_03AUG22, pp. 14 – 17.

Targeted VM Practices and TOR Program

In addition to scheduled 5-year trimming, Kentucky Power conducts off-cycle trimming to address hot spots or danger trees identified during line inspections, particularly when danger trees that could cause interruptions are detected. It includes customer notification and approval for tree removal for those located outside of the ROW. Each of these practices are consistent with or exceed practices at other electric utilities.[21]

Outage records reveal that a sizable percentage of interruptions under the tree cause codes is caused by trees outside of the ROW falling onto distribution lines and equipment. Accordingly, in 2018 Kentucky Power instituted a pilot program to widen existing ROWs to proactively address TOR outages, including the targeting of circuits with high exposure to danger trees. Table 4 presents Kentucky Power's annual capital spending on forestry, which increased in 2018 for the TOR pilot program. Kentucky Power reports the pilot produced a 15 percent reduction in SAIDI on circuits selected for ROW widening.

Table 4. Capital Investments - Forestry

Year	Capital Spend
2016	$3,718,526
2017	$3,789,067
2018	$8,925,445
2019	$14,401,892
2020	$8,439,419
2021	$12,753,906
2022	$9,444,069

Kentucky Power proposes to further enhance its VM Program to include targeted ROW widening (*TOR – Enhanced ROW Widening Program*) as one of the key components of its proposed incremental DRR, focusing on circuits that have experienced subpar reliability or on those most susceptible to TOR outages. The TOR program will supplement Kentucky Power's 5-year inspection cycles and enhance off-cycle trimming as a separate program. Guidehouse expects reliability gains realized via the TOR pilot program will be achieved on other circuits, subject to Commission approval of the TOR component of the DRR.

> ***Summary Assessment:*** *Kentucky Power's vegetation management program is consistent with or exceeds practices applied by electric utilities with comparable distribution system attributes and tree coverage. Kentucky Power's spending on VM aligns with industry benchmarks and it has met targeted trimming cycles. Clearance guidelines recognize differences in tree species with clearance envelopes that often exceed those established for other North American utilities. Kentucky Power's TOR pilot and proposed spending for TOR in its DRR is consistent with or exceeds industry practices, with its TOR pilot confirming measurable reliability benefits achieved by the TOR program. Trees located outside of the ROW is a leading cause of interruptions. Hence, Guidehouse expects that Kentucky Power's reliability will improve and SAIDI*

[21] Guidehouse's experience with VM at other utilities indicates Kentucky Power's TOR activities are more comprehensive than those of other utilities.

levels will more closely align with the benchmark peer group upon full implementation of the proposed TOR – Enhanced ROW Widening program.

2.4 Capacity Planning and Engineering Standards

Guidehouse's independent assessment of Kentucky Power's capacity planning and engineering standards addresses the following topics and questions.

- Are Kentucky Power's planning, design and maintenance practices based on standards that are consistent w/ good utility practice?
- Are the levels of Kentucky Power's capacity investments appropriate given historical growth in electricity demand for distribution substations and feeders?
- Are investment decisions made to balance capacity and reliability objectives?
- What criteria is applied to determine when and where reliability investments are needed, and what drives investment decisions?
- What are Kentucky Power's equipment maintenance policies and are these consistent with industry good practices?
- Where differences exist with the benchmark peer group, are there factors that need to be considered to explain and justify these differences?

To support its assessment, Guidehouse conducting an extensive review of Kentucky Power's planning and design processes, line and equipment loading criteria, and records to support our findings. Guidehouse interviewed Kentucky Power personnel responsible for planning and standards to confirm our understanding and review of Kentucky Power's practices and how decisions are made to determine the investments needed for distribution line capacity and reliability requirements. Guidehouse also reviewed prior Kentucky Commission Orders and reports, and Kentucky Power's 2023 rate filing, to supplement our independent review. Lastly, Guidehouse evaluated, via benchmarking analyses, Kentucky Power's standards and investments to those of other electric utilities with comparable distribution system properties and service territory attributes.

Distribution Line Capacity Planning

Kentucky Power's distribution line capacity planning and design criteria are documented in AEP's *Distribution System Planning Criteria* manual.[22] It describes each step in the process that planners follow to "financial requirements, the justification for implementing the proposed improvement plans to management, and the risk of not doing the project." The manual documents equipment loading and performance criteria, and guidelines each operating company should follow to determine the timing and type of upgrades or mitigation options needed to address loading and performance violations.

The manual also addresses reliability criteria, including how decisions on distribution line capacity investments should factor in reliability benefits. The document thoroughly describes the processes Kentucky Power follows to determine when line capacity upgrades are needed, equipment normal and emergency loading limits, and methods planners should apply to assess

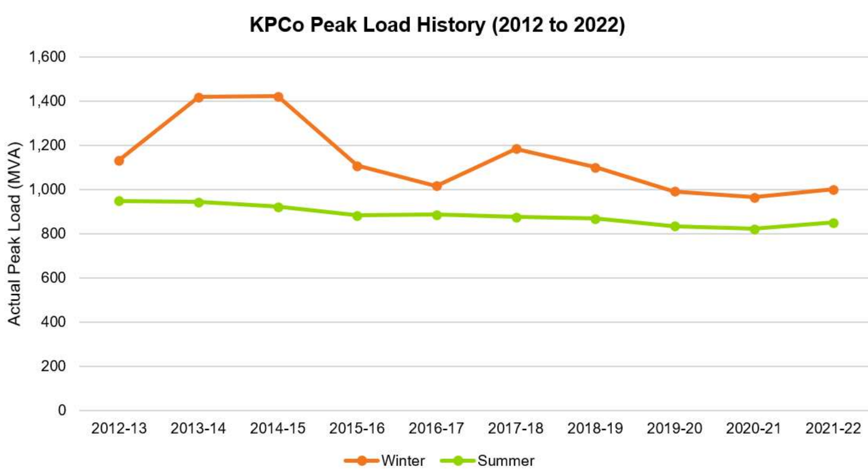
[22] American Electric Power, *Distribution System Planning Criteria*, October 2016 Revision. Prior revision dated May 2007.

candidate upgrades. The manual outlines options to address state loading or voltage violations on a least cost basis such as distribution line capacity expansion (e.g., new or higher rated substation transformers or new feeders), phase balancing, enhancing tie transfer capability; and approaches to mitigate dynamic performance violations such as harmonics and voltage flicker. Guidehouse interviewed Kentucky Power's distribution planning management team and confirmed the guidelines outlined in the manual are followed and described investments made over the past 12 years to comply with documented processes and planning criteria.

Kentucky Power's distribution planners use AEP's Distribution – Planning (DGP) model to determine the timing and magnitude of distribution capacity violations over a 10-year summer and winter demand forecast. The model lists every distribution substation, substation transformer, and feeder, along with equipment rating and capacity loading limits based on AEP planning and equipment loading standards. These standards include transformer capacity limits based on device condition (e.g., transformer windings) contingency or overload limits, and feeder tie transfer loading limits. The DGP identifies the year in which substation transformer or feeders reach or exceed 90 and 100 percent of equipment capacity limits.

Guidehouse first reviewed Kentucky Power's historical summer and winter system peak demands for the past 10 years. Figure 17 indicates peak demand has decreased commensurate with the decline in the number of customers over the past 10 years.[23] Except for investments required to serve localized increases in demand, the need for distribution substation and feeder capacity investment was invariably low during this period.

Figure 17. 10-Year Historical System Peak Demand



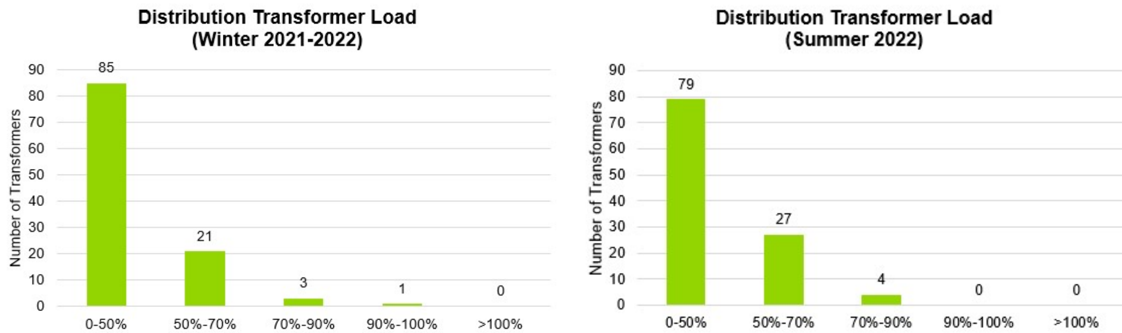
Source: Date provided by KPCO

To confirm the premise that minimal capacity investments were required over the past 10 years, Guidehouse reviewed Kentucky Power's actual and equipment loadings as of December 2022. Figure 18 presents 2022 actual substation transformer loadings as a percentage of distribution capacity limits. The chart indicates that only four of over 100 transformers are approaching 90 percent of summer capacity limits, while one is above 90 percent for winter, and none are overloaded during winter or summer. About 70 percent are below 50 percent of loading limits.

[23] The number of customers served has dropped from about 172,138 in 2013 to 164,184 in 2022, a 4.6% decline in the past 10 years.

These results confirm that historically, Kentucky Power had limited need for significant investment in capacity upgrades over the next 10 years. Recognizing that customer growth and peak loads have declined over the past 10 years, similar loading patterns can be inferred for prior years. Further, interruption data presented in Table 3 indicates the virtual absence of outages caused by substation transformer or circuit overloads.[24] Given these findings, it is unlikely feeder overloads over the past 10 to 12 years have had a material impact on reliability performance and indicate that Kentucky Power has made an appropriate level of capacity-related investments.

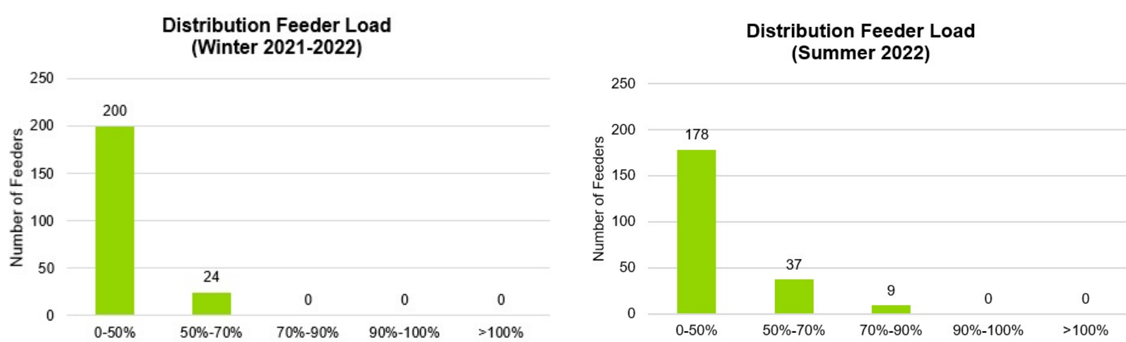
Figure 18. Kentucky Power Substation Transformer Loading (Winter 2021-2022 and Summer 2022)



Source: Date provided by KPCO

Similar to substation transformers, Kentucky Power's distribution feeders are well within capacity loading limits, with most feeders loaded to below 50 percent of capacity limits, and none expected to exceed 100 percent. Figure 19 presents actual Kentucky Power feeder loadings for 2022. Many feeders are expected to remain loaded below 50 percent over the 10-year forecast, with none exceeding 100 percent. Further, interruption data from Table 3 confirms the absence of outages caused by feeder overloads. Given these findings, it is unlikely feeder overloads over the past 10 to 12 years have had a material impact on reliability performance and indicate that Kentucky Power made the appropriate level of investment.

Figure 19. Distribution Feeder Loading (Winter 2021-2022 and Summer 2022)



Source: Date provided by KPCO

[24] For example, of the three distribution substation transformer failures over the past 10 years, none resulted in customer interruptions as incipient failures were detected prior to actual full failure, and Kentucky Power was able to proactively replace or repair the device.

Table 5 lists distribution substation and feeder capacity investments Kentucky Power has made over the past 15 years. It excludes capacity investments required to serve new customers such as transformers and line extensions. Notably, the level of capacity-related investments was modest compared to other investment categories due to the decline in load growth as noted above. While some investments were needed solely to serve localized increases in demand, such as new load centers, other investments were undertaken to improve reliability performance while increasing capacity. Of the total 15-year capital investment of $71 million, approximately 34 percent was for joint capacity/reliability projects. Guidehouse concludes balancing of capacity and reliability investments over the past 15 years is consistent with good utility practice and Kentucky Power's documented planning procedures.

Table 5. Capacity Investments: 2008 - 2022

Source: Data provided by KPCO

Summary Assessment: *Kentucky Power's distribution planning processes and equipment loading practices are consistent with or exceed industry practices. The steps that planners follow to justify and receive approval for capacity investments is based on engineering-based solutions designed to achieve least cost outcomes. Substation and distribution equipment loading criteria is based on capacity limits that recognize normal and contingency acceptable loadings – summer and winter - that minimize the likelihood of failure due to overload while maximizing the available capacity from these assets. The virtual absence of outages over the past several years caused by failures due to overloads confirms Kentucky Power has judiciously monitored loadings. Decreased peak demand has caused equipment loading to remain well below limits, while the absence of capacity overloads confirms that Kentucky Power has not under-invested in distribution capacity. Further, Kentucky Power has made capacity investments that jointly enhance reliability, demonstrating an appropriate balancing of investments to meet both capacity and reliability needs.*

Engineering and Design Standards

Kentucky Power's distribution system is comprised of long distribution lines that serve low customer density and remote load centers.[25] Most distribution feeders serving higher load density areas such as those in the Ashland district are rated 12.47kV while lines serving rural areas and remote loads are rated 34.5kV.[26] Table 6 summarizes Kentucky Power's distribution system properties by voltage class for each of their three districts. A substantial percentage of distribution feeders serving rural load are rated 34.5kV, a higher voltage rating often used by electric utilities serving rural or remote load centers. Feeders rated 34.5kV are designed for higher circuit loadings with less voltage variability compared to lower voltage lines (e.g., 12.47kV). However, Kentucky Power's 34.5kV lines are more susceptible to interruptions due to longer average length and higher voltage - higher voltage are more susceptible to sustained faults from tree contact due to lower flashover distances - compared to lower voltage lines.

Table 6. Kentucky Power Distribution System Properties

Kentucky Power Special District	Voltage Class	Total Miles of Primary Line[27]	Avg Line Length (mile)	Avg # of Customers	Avg # of Reclosers / Sectionalizers	Avg # of Regulators
Ashland	12 kV	1,957	31	758	9.1	2.3
	34 kV	591	59	928	17.5	5.2
Hazard	12 kV	681	30	683	12.0	3.2
	34 kV	1,836	57	779	15.5	4.2
Pikeville	12 kV	1,699	23	566	9.8	2.5
	34 kV	1,482	55	1,001	16.1	2.9
Total System	12 kV	4,348	27	648	9.7	2.4
	34 kV	3,908	57	888	16.0	3.8
	Total	**8,245**	**36**	**722**	**11.6**	**2.9**

To mitigate increased outage exposure, over the several years Kentucky Power has proactively installed reclosers and sectionalizers to limit outages - Table 6 highlights the large number of sectionalizing devices installed, particularly for longer 34.5kV circuits. Further, Kentucky Power recently has installed auto sectionalizing schemes to transfer unfaulted line sections to adjacent feeders to improve reliability performance. Up to 25 percent or greater of feeder capacity is reserved for load transfers on lines where auto sectionalizing schemes are located, consistent with utility practices.

About 25 percent of Kentucky Power's substations have two or more transformers capable of transferring load to the un-faulted device in the event of a device failure or bus fault. The remaining substations typically are those serving remote load centers or that are lightly loaded. For the latter, Kentucky Power uses mobile substation transformers to provide back-up in the event of a transformer failure at substations equipped with a single device. As noted earlier, Kentucky Power establishes transformer capacity limits based on loading criteria, transformer

[25] Historically, Kentucky Power's distribution system was designed to serve remote mining load, several of which have discontinued operations.

[26] Many distribution feeders rated 34.5kV (at the substation source) also serve load at lower voltage. These feeders include 34.5/12.47kV three-phase or 19.9kV / 7.2kV single-phase stepdown transformers located downstream of the substation.

[27] Line miles for circuits rated 34.5kV include downstream line segments that are stepped to lower voltages such as those rated 12.47kV.

type, condition, and number of devices; for the latter, Kentucky Power loads unfaulted transformers to a higher emergency rating with acceptable loss of life derived based on IEEE transformer loading guidelines.[28] Guidehouse's prior experience with similar utilities confirms that each of Kentucky Power's design and equipment loading practices described above is consistent with utilities with comparable service territory characteristics and distribution feeder properties.

Distribution feeders that provide capacity back-up to adjacent substations or that are part of an automated sectionalizing scheme (e.g., Distribution Automation Circuit Reconfiguration (DACR)) may be assigned lower loading limits, such as 75 percent of normal rating. Due to the length and location of a subset of distribution feeders serving rural load centers, the ability to transfer faulted lines sections to adjacent feeders is limited and usually is cost prohibitive to extend or upgrade line sections to enable load transfers. As of December 2022, Kentucky Power has installed five transfer schemes covering approximately 25 substations and 50 circuits on its distribution system.[29] Guidehouse views Kentucky Power efforts as consistent with leading utility practices as outlined in Table 7, which indicates several utilities are in the early stages of adopting DACR via Fault Location, Isolation, and Service Restoration (FLISR) while these schemes are already in place at Kentucky Power.

Table 7. Fault Isolation Benchmark Summary

Fault Isolation Scheme	Wide-Scale Basis	Next 5 Years	Pilot Program	Pilot Next 5 Years	Not Planned
Remote control of line switches and reclosers	17	3	0	0	0
Automated Fault Location, Isolation and Service Restoration (FLISR)	12	5	0	2	1

In 2015 Kentucky Power adopted the National Electric Safety Code (NESC) heavy loading distribution system design standard.[30] The higher design standard includes installation of higher-class poles, shorter spans, increased guying and equipment rated to withstand higher wind and ice loadings. Application of the higher design standard is applied on a selective basis - some locations are not suitable for the higher design standard, such as single pole replacements or where existing pole locations prohibit mid-span placement of poles with shorter spans. The transition to the heavy loading standard, over time, will enhance resiliency for major storm events, and it is viewed by Guidehouse as one that will enhance the resiliency of Kentucky Power's distribution system.

Grid Modernization

In addition to the adoption of the NESC heavy loading design standard, Kentucky Power has undertaken grid modernization and storm hardening initiatives to improve reliability and spending efficiency – each are central to Kentucky Power's Distribution Asset Management Program. Key among these is the installation of reclosers and sectionalizing devices, of which five are included in DACR and feeder tie transfer schemes installed over the past few years.

[28] IEEE Standard C57. 12.00: IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.
[29] Totals include fully automated and manually controlled switches and reclosers.
[30] Per NESC maps, Kentucky Power's service territory is located in a Medium loading zone.

Kentucky Power previously invested $3,463,115 in DACR. Kentucky Power now proposes to install additional DACR schemes as part of proposed DRR investments, which Guidehouse concludes will further improve reliability performance. Kentucky Power is also proposing other reliability enhancements such as installation of new feeder ties in conjunction with the installation of new substation or power transformers and reconfiguration of distribution circuits to reduce outage exposure.

Table 8 presents Kentucky Power's proposed spending plan on grid hardening and modernization initiatives included in the DRR. Up to $40 million (capital) along with $1.1 million (O&M) is proposed annually over the next five years, which Guidehouse concludes will materially improve reliability as measured by SAIFI and SAIDI indices.

Table 8. Proposed Grid Modernization Initiatives Under the DRR

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

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

Source: Everett Phillips Direct Testimony – p. 35

Summary Assessment: *Kentucky Power's engineering design and equipment selection criteria meet or exceed industry practices, particularly for electric utilities with comparable service territory characteristics and distribution system properties. Kentucky Power's distribution system design and equipment loading practices conform to system wide standards and criteria set forth by AEP, which Guidehouse views as consistent with good utility practices.[31] Substation transformer loading limits are based on industry-accepted standards outlined in IEEE guidelines while distribution feeder loading limits are based on tie transfer criteria and automated transfer schemes, where applicable. The transition to a higher design standard meets or exceeds utility practices and over time, will improve reliability performance during storms and normal outage events. Grid modernization initiatives proposed in the DRR have proven successful in prior applications and will further improve reliability if approved in Kentucky Power's pending rate filing.*

2.5 Equipment Maintenance and Inspections

Distribution Circuits

Similar to its capacity planning documentation, Kentucky Power equipment maintenance practices, procedures and schedules follow those documented in AEP manuals that apply to all operating companies. Guidehouse reviewed these procedures for several substation and distribution feeder equipment categories for consistency with good industry practices. We also benchmarked Kentucky Power practices with those of other comparable utilities. Guidehouse also reviewed programmatic maintenance or equipment replacements such as those outlined in the DRR.

The following sections describe Kentucky Power's distribution substation and circuit inspection and maintenance practices, and its compliance with completing each on schedule. It also highlights storm hardening and programmatic enhancement designed to improve reliability during normal outage events and major storms. The results of our review and assessment follows for each distribution category of lines or equipment.

1. **Distribution Circuit Inspections**

   Kentucky Power inspects each of its distribution feeders every two years, consistent with the Kentucky Public Service Commission's requirements outlined in the *Guidelines for Circuit Inspection* document. For overhead and underground lines, Kentucky Power follows the *Distribution Overhead/Underground Circuit Facilities Inspection and Maintenance* guidelines. Kentucky Power documents the results of its inspections electronically, highlighting abnormalities that require follow-up up mitigation.

   Guidehouse notes that the 2-year inspection requirements exceed industry practices, as some utilities have longer inspection cycles (3 to 5 years); in some instances, inspections are performed only on an as needed basis or during crew off-times. The inspection program has produced favorable results that have improved reliability. Table

[31] The AEP design standard recognizes locational factors that are unique or need to be considered for individual operating companies such as highly rural segments of Kentucky Power's distribution system where feeder ties to other substations may not be practical or cost prohibitive.

9 presents the quantity and cost of repairs resulting from circuit inspections, with up to $1 million spent annually for repairs.

Table 9. Inspection Repairs

Year	Circuit Repairs	Total Cost
2016	277	$925,998
2017	1096	$629,831
2018	323	$910,896
2019	850	$949,315
2020*	667	$569,649
2021*	530	$489,629
2022	1,232	$573,721
Total	**4,975**	**$5,049,040**

*Inspections, along with other maintenance activity, was impacted by Covid-19

2. Distribution Line Reclosers, Capacitors and Regulators

Along with other key equipment, Kentucky Power inspects distribution electronic and hydraulic reclosers between one and two years. Table 10 lists distribution line inspections completed since 2008, and confirms that Kentucky Power completes inspections on schedule.

Table 10. Distribution Equipment Maintenance - Inspections Completed

Year	Switched Cap		Fixed Cap	Recloser Electronic		Recloser Hydraulic		Regulator
	No. Inspections Completed	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices Inspected	No. Inspections Completed
2008	147	91	347	259	2017	1140	550	291
2009	268	84	391	292	1879	1084	607	316
2010	303	76	395	289	1928	1109	583	307
2011	327	88	437	311	1900	1097	611	323
2012	316	80	457	327	1816	1075	641	333
2013	299	74	490	353	1854	1055	618	319
2014	296	72	516	369	2079	1169	630	326
2015	283	71	533	392	1009	604	631	327
2016	278	69	552	414	1879	1066	619	319
2017	267	63	562	423	1567	875	626	326
2018	241	59	565	432	1317	746	595	304
2019	247	58	602	458	1387	742	624	322
2020	224	56	630	479	1926	1076	618	317
2021	80	42	646	512	988	541	471	236
2022	13	20	655	530	1423	767	439	227
2023	11	22	375	300	433	250	133	75
Total	**3827**	**1165**	**8773**	**6140**	**29160**	**14396**	**9968**	**5163**

3. Pole Inspections and Replacements

Pole inspection practices, intervals and treatment criteria are outlined in AEP's *Specifications for Inspection, Groundline Treatment & Reinforcement of Standing Wood*

Poles. Inspection requirements apply to the above and below groundline inspection and groundline treatment of standing wood poles performed by qualified and licensed contractors. The specification is detailed, with actions and treatments to be undertaken for increasing levels of deterioration (e.g., compliance with NESC rejection criteria) and original versus remaining pole circumference resulting from pole rot. The specification lists numerous pole data collected via the inspections such as pole class, height, species, manufacturer along with defective pole information such as above and below ground level condition. The condition of deteriorated ancillary equipment and devices such as broken guy wires, cracked cross-arms, loose connectors, defective cutouts, broken lightning arresters and unauthorized attached also is recorded.

Comprehensive pole inspections and testing are conducted every 10 years following limited inspections for the first 10 to 30 years (newer poles typically do not experience material levels of rot), which is consistent with industry practice for poles located in a decay zone comparable to Kentucky Power. Table 11 presents the inspections completed by Kentucky Power's contractors between 2014 and 2018. Inspection results indicate almost 98 percent of poles inspected passed remaining strength criteria for continued use or that otherwise could be reinforced via pole treatment. These results are consistent with utilities for whom Guidehouse has conducted similar reviews. Pole inspections have followed the 10-year inspection schedule as of 2019.

Table 11. Pole Inspections (2014 – 2018)

Inspection Results	Quantities
Non-Reject	32,448
Non-Restorable Reject	527
Priority Non-Restorable Reject	379
Priority Restorable Reject	611
Restorable Reject	284
Unset	1
Total	**34,250**

Table 12 lists the number of poles Kentucky Power replaced resulting from the inspections, with up to three million spent annually. These capitalized amounts are exclusive of other treatment options Kentucky Power applied during inspections.

Table 12. Pole Replacements

Year	Poles Replaced	Total Cost
2016	339	$923,942
2017	178	$622,232
2018	714	$2,725,462
2019	346	$1,728,746
2020	355	$1,097,202
2021	223	$1,359,284
2022	413	$1,261,073
Total	**2,568**	**$9,717,941**

In addition to or outside of scheduled inspections, deficient poles, crossarms and leaning poles are detected during the 2-year Inspection Guidelines. Given the above level of detail, Kentucky Power inspection history and prior spending, Guidehouse concludes Kentucky Power's pole inspection practices and follow up mitigation is consistent with good utility practice.

Distribution Substations

The following subsections summarize the results of the benchmarking of Kentucky Power's substation equipment inspection and maintenance intervals versus those of the benchmark utility group. Additional details follow for major equipment categories. Table 13 confirms Kentucky Power's substation equipment maintenance cycles are consistent with benchmark utility practices.

Table 13. Substation Equipment Maintenance Benchmarks

Substation Maintenance Cycles	Average Cycle Time (12 Utilities)	Kentucky Power	Kentucky Power Comments
Power Transformers	5.1	4/5/8/10	Varies by transformer type
Relays	5.6	--	Follows NERC compliance
DC Supply (Batteries)	N/A	1	Annual detailed inspection
Circuit Breakers	5.6	6	For most breaker types

1. Substation Transformers

Transformer inspection and maintenance is performed by Kentucky Power Transmission Field Services (TFS), with specific procedures outlined in AEP's *Transformer Maintenance Work Standard Practices* document. The document is comprehensive, and it lists major inspection and overhaul intervals and maintenance activities along the specific details for conducting dissolved gas in oil analyses, including increasing levels of risk classification associated with the results of the analysis along with actions to be undertaken for each level. Table 13 confirms that Kentucky Power inspection and maintenance intervals are consistent with peer group practices, while Kentucky Power confirmed via tracking reports (See Appendix for details) that substation transformer inspections have been completed on schedule, with actions undertaken to address deficiencies found through inspections.

The effectiveness of Kentucky Power's transformer inspection maintenance is confirmed by the relatively low number of transformer failures and low contribution to reliability indices. Over the last five years, Kentucky Power has only experienced three substation transformer failures in its distribution substations. Kentucky Power assesses normal loading annually at substations and conducts maintenance on power transformers per planned schedules. Kentucky Power provided records that transformer maintenance has been completed on schedule. A sample transformer inspection report highlighting maintenance cycles for transformers under Kentucky Power ownership is presented in the Appendix. Similar reports are prepared for other substation equipment..

2. **Substation Circuit Breakers**

Substation Circuit Breakers inspection and maintenance is performed by Kentucky Power Transmission Field Services (TFS), with specific procedures outlined in AEP's *Circuit Breaker Maintenance Work Standard Practices Procedure* document.[32] The document is comprehensive, and it lists major inspection and overhaul intervals and maintenance activities along the specific details on the level of maintenance required based on condition assessment reports, breaker type, interruption medium (e.g., gas, oil, air), voltage, with results recorded via electronic data collection.

Table 13 confirms that Kentucky Power inspection and maintenance intervals are consistent with peer group practices, while Kentucky Power confirmed via tracking reports that circuit breaker inspections have been completed on schedule, with actions undertaken to address deficiencies or abnormal readings, among other inspection results. Similar to power transformers, the effectiveness of Kentucky Power's breaker inspection and maintenance is confirmed by the relatively low number of device failures and low contribution to reliability indices.

3. **Protective Relays**

Protective relay inspection and testing is performed by Kentucky Power Transmission Field Services (TFS), with specific procedures outlined in AEP's Protective Relay Maintenance Practices Procedure document. The document is comprehensive, and it lists inspection, testing and calibration of electromechanical and digital relays. While the document does not specify testing schedules, it does state that Kentucky Power follows NERC relay testing compliance intervals of PRC-005.

Table 13 confirms that Kentucky Power inspection and maintenance intervals are consistent with the benchmark utility practices. Similar to distribution substation transformers, the effectiveness of Kentucky Power's relay inspection and testing program is confirmed by the relatively low number of device failures and low contribution to reliability metrics as confirmed in Table 3.

Programmatic and Targeted Replacements

Kentucky Power has implemented a series of targeted and programmatic distribution line and equipment upgrades and replacement programs to improve reliability performance, focusing on the hardening of distribution assets to better withstand major storms. Several of these programs are based on inspection reports and data obtained from outage records under the equipment cause code. Two areas where equipment failures have caused a high level of interruptions include porcelain insulator and defective fused cutouts. While the number of insulators replaced is not readily available (insulators are not unit of property and therefore not individually tracked), Kentucky Power has replaced large quantities of defective fused cutouts over the past several years, highlighted in Table 14.

[32] Practices apply to devices located both within and outside the substation fence.

Table 14. Fused Cutout Replacements

Year	No. of Cutouts Replaced	Total Investment Cost
2016	2387	$679,184
2017	2688	$862,032
2018	4,464	$1,555,841
2019	3,817	$1,580,662
2020	1,270	$438,995
2021	1,334	$335,180
2022	1,413	$371,261
Total	**17,373**	**$5,823,155**

In addition to the above and pole replacement, Kentucky Power has replaced defective equipment in several other areas as part of its grid modernization and reliability improvement programs. Table 15 summarizes amounts spent over the past three years for several of these programs.

Table 15. Equipment Replacement Programs (2020 – 2022)

Year	Storm Hardening	Reliability Projects	Small Wire Replacements	Spacer Cable Replacements	Station Line Projects
2020	$434,710	$--	$259,700	$--	$--
2021	$--	$370,444	$499,850	$710,000	$150,000
2022	$--	$1,015,913	$--	$--	$--
Total	**$434,710**	**$1,386,357**	**$759,550**	**$710,000**	**$150,000**

Summary Assessment: *Kentucky Power's equipment maintenance procedures and scheduling meet or exceed industry practices. Kentucky Power's maintenance intervals, inspection, and testing practices align with those set forth by AEP, which Guidehouse views as consistent with good utility practices. Procedures for substation transformers, breakers, protective relays, and ancillary equipment are comprehensive and recognize differences in equipment type, supplier and performance history; while distribution circuit practices, including full circuit inspections, meet or exceed industry practices as confirmed via benchmarking analysis. Furthermore, Kentucky Power has proactively addressed equipment condition or performance issues over the past several years through spending programs that aim to achieve maximum reliability benefits; and proposes to further advance these programs via its proposed Distribution Reliability Rider.*

2.6 Storm Restoration Procedures and Performance

Restoration Procedures

Guidehouse's independent assessment of Kentucky Power's storm performance includes an extensive review of Kentucky Power's emergency and storm procedures, Incident Command

System (ICS) and various other factors to support our findings. We interviewed Kentucky Power personnel responsible for Emergency Response to confirm our understanding and review of Kentucky Power's practices and how decisions are made to ensure that procedures are in place and followed during storm events. Guidehouse's evaluation and assessment addresses the following topics and questions.

- What are the roles and responsibilities of Kentucky Power's personnel and outside contractors during major storms and events?
- Are storm restoration activities centralized or decentralized?
- Is the deployment of the Incident Command System (ICS) consistent with utility good practices and for processes, practices, what are the roles/responsibilities?
- What are Kentucky Power's processes for pre-storm preparation and notification?
- What processes are used for damage and hazard assessment?

Based on Guidehouse assessment, Kentucky Power has a comprehensive Emergency Response Plan (ERP) to safely restore electric service to customers as quickly as possible. Kentucky Power's ERP is in line with industry best practices. It includes procedures for pre-storm plans, an Incident Management Team structure, restoration procedures and storm outage reporting procedures for customers, governmental agencies, and Media.

Kentucky Power's ERP allows the flexibility to adjust activities and personnel assignments to enable more efficient storm restoration efforts as events evolve. Though storm restoration efforts are mostly centralized, when the number of outages per district reaches certain thresholds, some activities are decentralized for higher efficiency. One example of this is the options to enable Trouble dispatchers per district while keeping Central dispatchers for upstream issues and items that require broader visibility of the system.

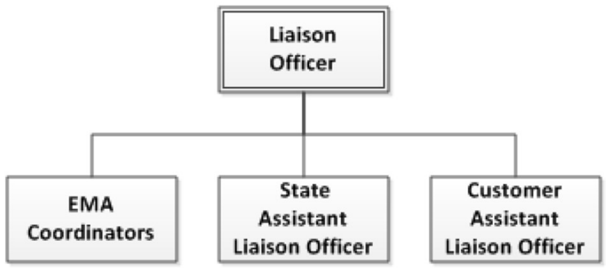
In terms of pre-storm preparations, Kentucky Power follows industry best practices which includes conducting annual Storm-Preparedness employee training, utilizing a weather prediction model, establishing mutual assistance programs and channels of communications with the public, including Federal, State and Local entities as well as with customers and media. The Storm-Preparedness trainings include comprehensive and refresher programs for every position identified in the ERP.

Kentucky Power's ICS training includes storm scenarios and associated responses. In addition, the ICS trainings require KPCO employees to simulate the expected actions that would occur in real storms to make assessment of damages, required crews and actions required.

Kentucky Power's mutual assistance programs expand beyond internal agreements within AEP operating companies to external utilities across other states, and is a member of the EEI Mutual Assistance Program and various Regional Mutual Assistance Groups (RMAGs). As part of preparing for a storm, Kentucky Power leverages its weather prediction model to estimate the probability of the event occurring to start mobilizing and stagging its personnel and equipment.

In terms of coordination and communication with the public, the ERP includes a Response Organization to ensure that the Emergency Management Agency (EMA) as well as local government and customers are kept informed and that there are two-way communications where needed. The Response Organization includes roles for the following: Liaison Officer, EMA Coordinators, State Assistant Liaison Officer and Customer Assistant Liaison Officer as illustrated in Figure 20.

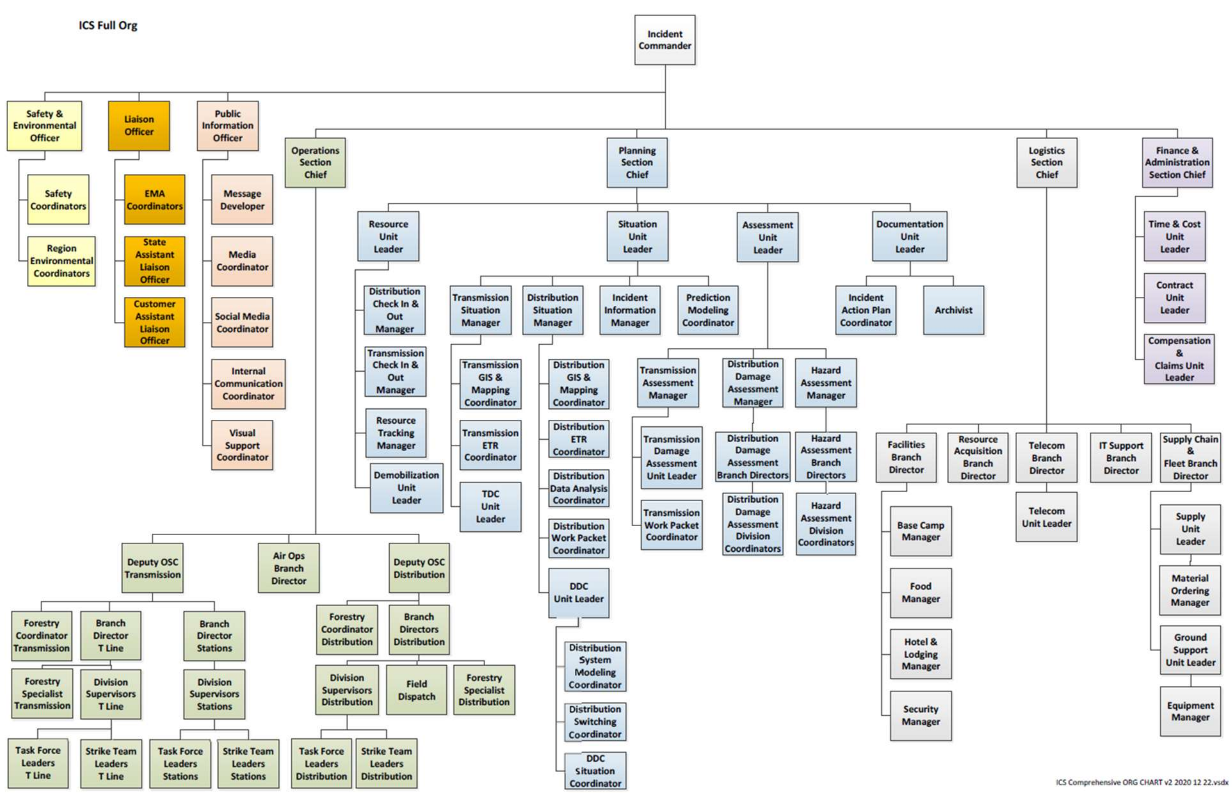
Figure 20. Response Organization- Liaison Officer



Source: KPCO ERP

Kentucky Power's ICS delineates roles and responsibilities based on employees' skills, competencies, and training to ensure safe and timely emergency response and restoration. Each role has a clear reporting structure, required training and role description, and is documented in AEP's ICS Roles and Responsibilities version 4-03. The ICS structure chart is presented in Figure 21, and is an example of how Kentucky Power's processes enable employees to expediently mobilize to their designated Storm roles to support rapid and safe restoration of its customers.

Figure 21. ICS Structure- ICS Complete Organizational Chart



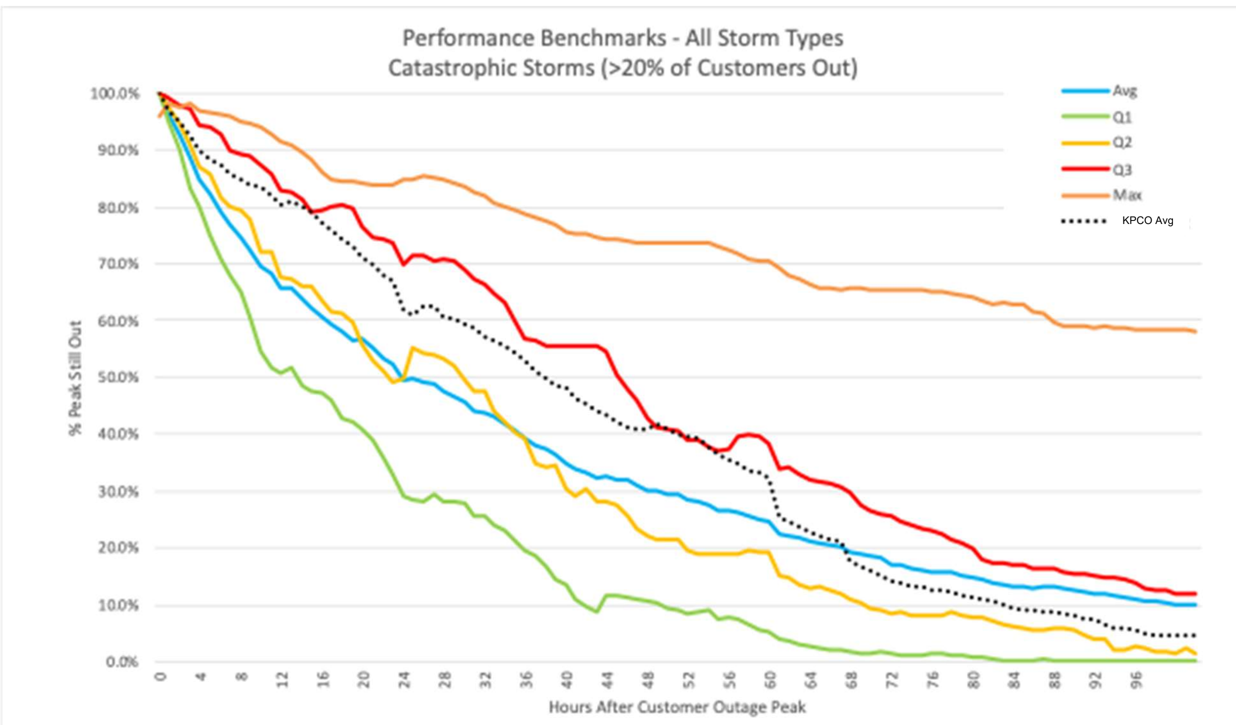
Source: KPCO ICS

Storm Restoration Performance

Guidehouse conducted storm performance benchmarking for an extensive peer group of U.S. utilities to assess how efficiently Kentucky Power restores power to customers in terms of cost and restoration times. The benchmark analysis includes storms where 20 percent or more of the customers base are interrupted. The analysis considers all major storm types such as weather conditions (i.e., snow, thunderstorms, ice, and wind).

Figure 22 compares Kentucky Power's restoration times versus industry performance benchmarks. It confirms that Kentucky Power, via adherence to their Emergency Response Program, restored a substantial percentage of their customers in a timeframe similar to that of other utilities across the U.S. Results indicate that Kentucky Power's storm performance over the past 15 years falls within the average response times of U.S. utilities, and most restoration times for Kentucky Power falls within the range of the industry benchmark. Kentucky Power's restoration times are expected to decrease following the planned installation of additional DACR schemes proposed in the Distribution Reliability Rider.

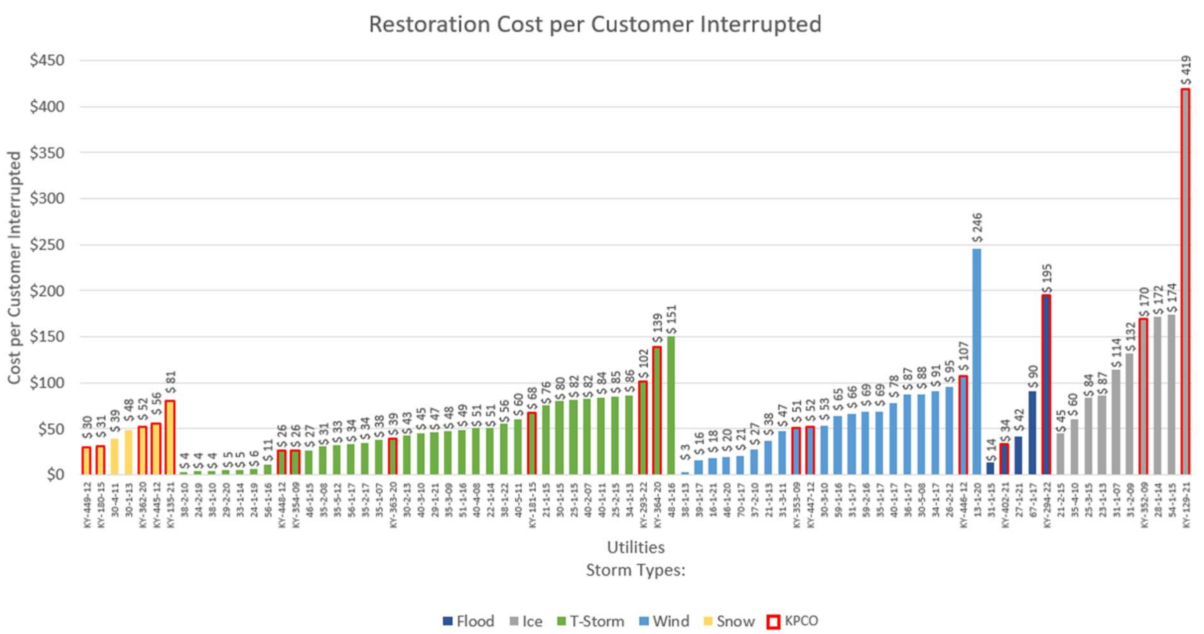
Figure 22. Kentucky Power Restoration Times Versus Industry Benchmark



Source: First Quartile Consulting and KPCO

Figure 23 is a comparison of Kentucky Power restoration costs versus industry benchmark. (Individual storm restoration costs appear in the Appendix,) This shows that compared to other Utilities, Kentucky Power restoration costs ranges are closer to the average for some storms such as wind and snowstorms. For ice storms, Kentucky Power restoration costs are above average. This is likely the result of the large amount of ice build-up in its service area during recent ice storms and more extensive tree coverage (per Table 2, Kentucky Power at 99 percent has among the highest percent of tree coverage among the peer group), and likely resulted in greater damage and more costly repairs compared to prior storms.

Figure 23. Kentucky Power Restoration Costs Versus Industry Benchmark



Source: First Quartile Consulting and KPCO

3. Conclusions

From its detailed review and analysis of data covering the period 2008 to current, industry benchmark data for utilities with comparable service territories and distribution systems, and interviews with Kentucky Power, Guidehouse offers the following findings and conclusions.

Kentucky Power's,

- Distribution system is located in a region with among the highest tree coverage and density for the peer group of electric utilities, with low customer density and high average circuit length, each of which are contributing factors to reliability performance;
- Reliability performance as measured by System Average Interruption Frequency Index (SAIFI) is within the peer group average. Reliability performance as measured by System Average Interruption Duration Index (SAIDI) is slightly above the peer group average;
- Tree-related customer interruptions from outside the right-of-way (TOR) is the leading cause of outages. Efforts are underway and Kentucky Power proposes to reduce TOR interruptions via incremental investments under its proposed Distribution Reliability Rider (DRR);
- Spending on capital projects and maintenance is at or above the peer group average, which is notable for a utility that has experienced a decrease in customers and demand;
- Vegetation management practices are at or above industry practices, with trimming completed on schedule and clearances based on species type and location;
- Equipment failures are the second leading cause of customer interruptions. Proactive efforts to reduce customer interruptions via replacement of equipment with high failure rates (such as cutouts and insulators) are underway. Kentucky Power proposes to expand its ongoing replacement program through incremental investments under the proposed DRR;
- Capital spending on distribution assets as measured by total distribution investments and number of customers is at or above industry averages, which is notable as Kentucky Power has experienced a decline in load growth and number of customers served;
- Spending on distribution maintenance as measured by distribution line miles and number of customers is at or above industry averages;
- Equipment maintenance practices, procedures and inspection intervals is consistent with industry practices, with inspection cycles completed on time;
- Emergency restoration procedures, which include a centralized Incident Command structure, are consistent with industry practices; and
- Storm restoration intervals as measured by customers restored over storm duration, and restoration costs are within industry averages for most types of storms (e.g., wind and snow), except ice storms where costs are higher due to tree density and storm severity.

Appendices

Candidate Peer Group Utilities

#	Utility	State	Type	Service Territory Tree Coverage	Customer Count[33]	Criteria 1 *(State)*	Criteria 2 *(Type)*	Criteria 3 *(Urban / Rural)*	Criteria 4 *(>85%)*	Criteria 5 *(>10,000)*
1	Appalachian Power Co	KY	IOU	--	--	✓	✓			
2	Barton Village, Inc	VT	Municipal	--	--	✓				
3	Big Sandy Rural Elec Coop Corp	KY	Cooperative	100%	12,778	✓	✓	✓	✓	✓
4	Blue Grass Energy Coop Corp	KY	Cooperative	75%	--	✓	✓	✓		
5	Central Maine Power Co	ME	IOU	95%	634,601	✓	✓	✓	✓	✓
6	City of Bowling Green - (KY)	KY	Municipal	--	--	✓				
7	City of Burlington Electric - (VT)	VT	Municipal	--	--	✓				
8	City of Frankfort - (KY)	KY	Municipal	--	--	✓				
9	City of Glasgow - (KY)	KY	Municipal	--	--	✓				
10	City of New Martinsville - (WV)	WV	Municipal	--	--	✓				
11	City of Owensboro - (KY)	KY	Municipal	--	--	✓				
12	City of Paducah - (KY)	KY	Municipal	--	--	✓				
13	City of Princeton - (KY)	KY	Municipal	--	--	✓				
14	Clark Energy Coop Inc - (KY)	KY	Cooperative	77%	--	✓	✓	✓		
15	Craig-Botetourt Electric Coop	WV	Cooperative	94%	484	✓	✓	✓	✓	
16	Cumberland Valley Electric, Inc.	KY	Cooperative	98%	23,831	✓	✓	✓	✓	✓
17	Duke Energy Kentucky	KY	IOU	89%	142,504	✓	✓	✓	✓	✓
18	Eastern Maine Electric Coop	ME	Cooperative	96%	12,708	✓	✓	✓	✓	✓
19	Farmers Rural Electric Coop Corp - (KY)	KY	Cooperative	76%	--	✓	✓	✓		
20	Fleming-Mason Energy Coop Inc	KY	Cooperative	82%	--	✓	✓	✓		
21	Grayson Rural Electric Coop Corp	KY	Cooperative	98%	14,813	✓	✓	✓	✓	✓

[33] Ten-year average (2013-2022). Calculated using customer data from the U.S. Energy Information Administration. Source: [Annual Electric Power Industry Report, Form EIA-861 detailed data files]

22	Green Mountain Power Corp	VT	IOU	94%	264,575	✓	✓	✓	✓	✓
23	Harrison Rural Elec Assn, Inc	WV	Cooperative	98%	6,884	✓	✓	✓	✓	
24	Henderson City Utility Comm	KY	Municipal	--	--	✓				
25	Inter County Energy Coop Corp	KY	Cooperative	78%	--	✓	✓	✓		
26	Jackson Energy Coop Corp - (KY)	KY	Cooperative	96%	51,119	✓	✓	✓	✓	✓
27	Jackson Purchase Energy Corporation	KY	Cooperative	72%	--	✓	✓	✓		
28	Kenergy Corp	KY	Cooperative	65%	--	✓	✓	✓		
29	Kentucky Power Co	KY	IOU	99%	166,243	✓	✓	✓	✓	✓
30	Kentucky Utilities Co	KY	IOU	72%	--	✓	✓	✓		
31	Liberty Utilities (Granite State Electric)	NH	IOU	98%	44,932	✓	✓	✓	✓	✓
32	Licking Valley Rural E c	KY	Cooperative	99%	17,327	✓	✓	✓	✓	✓
33	Louisville Gas & Electric Co	KY	IOU	88%	--	✓	✓			
34	Meade County Rural EC	KY	Cooperative	81%	--	✓	✓	✓		
35	Monongahela Power Co	WV	IOU	98%	388,333	✓	✓	✓	✓	✓
36	New Hampshire Elec Coop Inc	NH	Cooperative	97%	81,297	✓	✓	✓	✓	✓
37	Nolin Rural Electric Coop Corp	KY	Cooperative	75%	--	✓	✓	✓		
38	Owen Electric Coop Inc	KY	Cooperative	91%	61,365	✓	✓	✓	✓	✓
39	Pennyrile Rural Electric Coop	KY	Cooperative	70%	--	✓	✓	✓		
40	Public Service Co of NH	NH	IOU	88%	81,297	✓	✓	✓	✓	✓
41	Salt River Electric Coop Corp	KY	Cooperative	81%	--	✓	✓	✓		
42	Shelby Energy Co-op, Inc	KY	Cooperative	76%	--	✓	✓	✓		
43	South Kentucky Rural EC	KY	Cooperative	89%	68,891	✓	✓	✓	✓	✓
44	Taylor County Rural EC	KY	Cooperative	85%	26,663	✓	✓	✓	✓	✓
45	The Potomac Edison Company	WV	IOU	98%	204,050	✓	✓	✓	✓	✓
46	Town of Hardwick	VT	Municipal	--	--	✓				
47	Town of Stowe-(VT)	VT	Municipal	--	--	✓				
48	Tri-County Elec Member Corp (TN)	KY	Cooperative	90%	26,261	✓	✓	✓	✓	✓

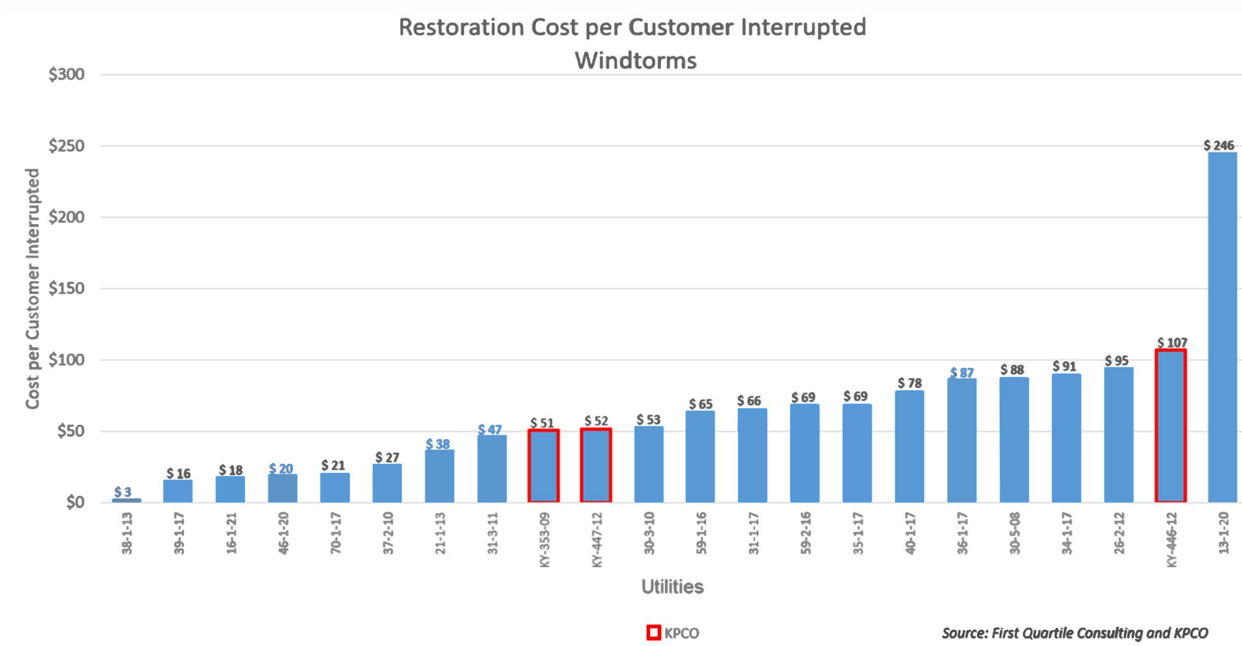
49	Unitil Energy Systems	NH	IOU	--	--	✓	✓			
50	Vermont Electric Cooperative, Inc	VT	Cooperative	90%	38,992	✓	✓	✓	✓	✓
51	Versant Power (Emera Maine)	ME	IOU	90%	164,510	✓	✓	✓	✓	✓
52	Village of Enosburg Falls - (VT)	VT	Municipal	--	--	✓				
53	Village of Hyde Park - (VT)	VT	Municipal	--	--	✓				
54	Village of Jacksonville - (VT)	VT	Municipal	--	--	✓				
55	Village of Johnson - (VT)	VT	Municipal	--	--	✓				
56	Village of Morrisville - (VT)	VT	Municipal	--	--	✓				
57	Village of Northfield - (VT)	VT	Municipal	--	--	✓				
58	Village of Orleans - (VT)	VT	Municipal	--	--	✓				
59	Warren Rural Elec Coop Corp	KY	Cooperative	76%	--	✓	✓	✓		
60	West Kentucky Rural E C C	KY	Cooperative	74%	--	✓	✓	✓		
61	Wheeling Power Co	WV	IOU	--	--	✓	✓			
					TOTAL Count	61	42	38	23	21

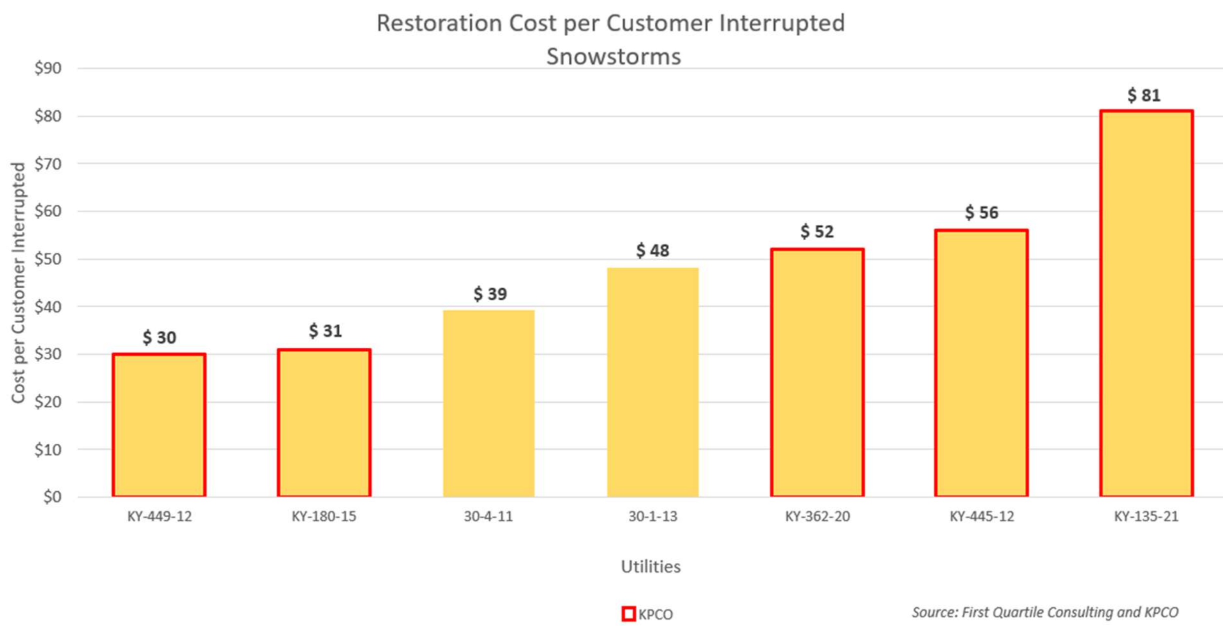
Transformer Maintenance Schedules

Operating Company	Station	Asset Name	Asset Owner	Device KV	Device Status	Commissioning Date	Maintenance Responsiblity	PT Application	Minor Maintenance Most Recent Execute Time	Minor Maintenance Current Schedul	Minor Maintenance Normal Schedul	Minor Maintenance Due Date (Current Schedule)
Kentucky Power	ALLEN (KP)	TR-1	Distribution	46 kV	In Service	5/5/1998	Transmission	Power	5/11/1998	0	0	
Kentucky Power	ASHLAND	BANK 1 300	Distribution	69 kV	In Service	12/31/1899	Transmission	Power	12/6/2012	120	120	12/6/2022
Kentucky Power	ASHLAND SERV BLD	Cap Spare Waukesha 25MVA 69-12KV	Distribution	69 kV	In Service	10/15/2018	Transmission	Power		120	120	10/15/2028
Kentucky Power	BAKER 765KV	SPARE XFMR 3	Distribution	69 kV	Spare - Capitalized	6/25/1997	Transmission	Power	10/19/2009	120	96	10/19/2019
Kentucky Power	BAKER 765KV	SPARE XFMR 2	Distribution	69 kV	Spare - Capitalized	11/8/1982	Transmission	Power	5/10/2003	120	72	5/10/2013
Kentucky Power	BAKER 765KV	SPARE XFMR 1	Distribution	69 kV	Spare - Capitalized	11/1/1991	Transmission	Power	7/6/2006	0	0	
Kentucky Power	BARRENSHE	TR-1	Distribution	69 kV	In Service	1/1/1994	Transmission	Power	10/2/2023	120	120	10/2/2033
Kentucky Power	BEAVER CREEK	#9 BANK DISTRI	Distribution	138 kV	In Service	5/15/2007	Transmission	Power	4/9/2020	120	120	4/9/2030
Kentucky Power	BECKHAM	TR-1	Distribution	138 kV	In Service	12/14/2005	Transmission	Power	10/30/2017	120	120	10/30/2027
Kentucky Power	BEEFHIDE	TR 1	Distribution	138 kV	In Service	1/26/1994	Transmission	Power	2/14/2022	120	120	2/14/2032
Kentucky Power	BELFRY	1 DISTRI	Distribution	46 kV	In Service	12/31/1977	Transmission	Power	12/9/2019	72	72	12/9/2025
Kentucky Power	BELHAVEN	TRF 1 300	Distribution	138 kV	In Service	3/1/1986	Transmission	Power	10/5/2020	120	120	10/5/2030
Kentucky Power	BELLEFONTE	BANK-6 300	Distribution	138 kV	In Service	11/1/1971	Transmission	Power	12/1/2012	120	120	12/1/2022
Kentucky Power	BIG SANDY 138KV	BANK- 4	Distribution	138 kV	In Service	8/22/2007	Transmission	Power	9/20/2018	120	120	9/20/2028
Kentucky Power	BIG SANDY 138KV	BANK-3 7005	Distribution	138 kV	In Service	11/1/1984	Transmission	Power	7/23/2014	120	120	7/23/2024
Kentucky Power	BLUE GRASS	TR-1	Distribution	69 kV	In Service	4/17/1995	Transmission	Power	9/19/2018	72	72	9/19/2024
Kentucky Power	BONNYMAN	#1 BANK	Distribution	69 kV	In Service	2/23/2012	Transmission	Power		120	120	2/23/2022
Kentucky Power	BREAKS	TR-2	Distribution	69 kV	In Service	1/19/2016	Transmission	Power		120	120	1/19/2026
Kentucky Power	BULAN	1 BANK DISTRI	Distribution	69 kV	In Service	6/11/1980	Transmission	Power	7/20/2017	72	72	7/20/2023
Kentucky Power	BURDINE	TR-1	Distribution	46 kV	In Service	5/16/1998	Transmission	Power	5/20/1998	0	0	
Kentucky Power	BURTON	#1 BANK #1 BNK (TO BE REMOVED)	Distribution	46 kV	In Service	8/16/2001	Transmission	Power	8/16/2001	0	0	
Kentucky Power	BUSSEYVILLE	TR 2	Distribution	138 kV	In Service	3/12/2008	Transmission	Power	5/15/2018	120	120	5/15/2028
Kentucky Power	BUSSEYVILLE	TR 1 300	Distribution	138 kV	In Service	7/1/1978	Transmission	Power	6/27/2014	120	120	6/27/2024
Kentucky Power	CANNONSBURG	Transformer #1	Distribution	69 kV	In Service	10/31/2018	Transmission	Power		48	48	10/31/2022
Kentucky Power	CEDAR CREEK	TR 2	Distribution	138 kV	In Service	9/13/2019	Transmission	Power		120	120	9/13/2029
Kentucky Power	CEDAR CREEK	CAPITALIZED SPARE	Distribution	138 kV	Spare - Capitalized	11/10/1982	Transmission	Power	10/9/2013	72	72	10/9/2019
Kentucky Power	CEDAR CREEK	CAPITALIZED SPARE	Distribution	138 kV	Spare - Capitalized	11/10/1982	Transmission	Power	10/9/2013	72	72	10/9/2019
Kentucky Power	CHAVIES	1 BANK DISTRI	Distribution	69 kV	In Service	5/4/1986	Transmission	Power	5/1/1999	0	0	
Kentucky Power	COALTON	BANK-1 300	Distribution	69 kV	In Service	6/1/1979	Transmission	Power	1/8/2020	72	72	1/8/2026
Kentucky Power	COLEMAN	2 BANK DISTRI	Distribution	69 kV	In Service	1/1/1989	Transmission	Power	3/22/2004	120	120	3/22/2014
Kentucky Power	COLEMAN	1 BANK SINGLE	Distribution	69 kV	In Service	2/3/1994	Transmission	Power	9/1/1994	0	0	
Kentucky Power	COLLIER	1 BANK DISTRI	Distribution	69 kV	In Service	1/1/1977	Transmission	Power	7/23/2019	120	120	7/23/2029
Kentucky Power	DAISY	1 BANK DISTRI	Distribution	69 kV	In Service	10/16/1989	Transmission	Power	7/24/2003	0	0	
Kentucky Power	DEWEY	2 BANK #2	Distribution	138 kV	In Service	8/7/1975	Transmission	Power	10/16/2023	48	48	10/16/2027
Kentucky Power	DRAFFIN	1 BANK DISTRI	Distribution	46 kV	In Service	8/28/1991	Transmission	Power	5/9/2023	72	72	5/9/2029
Kentucky Power	EAST PRESTONSBURG	TR-1	Distribution	46 kV	In Service	4/10/1999	Transmission	Power	7/14/2011	120	120	7/14/2021
Kentucky Power	ELWOOD (KP)	1 BANK DISTRI	Distribution	46 kV	In Service	1/1/1975	Transmission	Power	12/14/2021	120	120	12/14/2031
Kentucky Power	ENGLE	1 BANK DISTRI	Distribution	69 kV	In Service	6/1/1994	Transmission	Power	12/24/2008	120	120	12/24/2018
Kentucky Power	FALCON	TR-T2	Distribution	69 kV	In Service	9/28/2021	Transmission	Power		120	120	9/28/2031
Kentucky Power	FEDS CREEK	1 BANK DISTRI	Distribution	69 kV	In Service	12/31/1899	Transmission	Power	7/18/2013	120	120	7/18/2023

Restoration Cost Graphs per Storm Types


Restoration Cost per Customer Interrupted
Thunderstorms
Cost per Customer Interrupted
Utilities
KPCO
Source: First Quartile Consulting and KPCO


Restoration Cost per Customer Interrupted
Windtorms
Cost per Customer Interrupted
Utilities
KPCO
Source: First Quartile Consulting and KPCO


Restoration Cost per Customer Interrupted
Snowstorms
Cost per Customer Interrupted
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
$ 30
$ 31
$ 39
$ 48
$ 52
$ 56
$ 81
KY-449-12
KY-180-15
30-4-11
30-1-13
KY-362-20
KY-445-12
KY-135-21
Utilities
KPCO
Source: First Quartile Consulting and KPCO

VERIFICATION

The undersigned, Eugene L. Shlatz, being duly sworn, deposes and says he is an independent consultant for Guidehouse, Inc., 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.

Eugene L. Shlatz

State of Ohio	)	
	) ss	Case No. 2023-00159
County of Franklin	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State by Eugene L. Shlatz, on 4th of December, 2023

Notary Public

My Commission Expires Feb 22nd, 2028

Notary ID Number 2023-RE-860163

NOTARY PUBLIC STATE OF OHIO

ZACHARY RAMON WILLIAMS
Notary Public
State of Ohio
My Comm. Expires
February 22, 2028

COMMONWEALTH OF KENTUCKY

BEFORE THE

KENTUCKY PUBLIC SERVICE COMMISSION

In the matter of,

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

REBUTTAL TESTIMONY OF

EUGENE L. SHLATZ

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
EUGENE L. SHLATZ ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2023-00159

TABLE OF CONTENTS

Exhibits

Resume of Eugene L. Shlatz	Exhibit No. ELS-1
Independent Review & Assessment of Reliability Performance and Distribution System Investments	Exhibit No. ELS-2

**REBUTTAL TESTIMONY OF
EUGENE L. SHLATZ ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

CASE NO. 2023-00159

I. INTRODUCTION

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

A. My name is Eugene L. Shlatz. I have been employed in various capacities by Guidehouse Inc. (Guidehouse)[1] since 1999, including twelve years as a Director in Guidehouse's Energy, Sustainability & Infrastructure Practice. My business address is 77 South Winooski Ave., Burlington, Vermont.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND

A. I have more than 30 years' experience in electric utility operations, engineering, and electric pricing. I have worked for Guidehouse over the past 23 years, where I was responsible for managing studies of electric utility system reliability, renewable energy, and advanced energy systems. I recently retired from Guidehouse, but continue to offer the same services that I previously provided as a full-time consultant.[2] I have supported filings before federal, state, and Canadian provincial regulatory commissions on a range of electric utility matters, including system planning and operations, reliability, renewables integration, and retail and wholesale rates.

[1] Previously, Navigant Consulting, Inc.
[2] Mr. Shlatz currently is assigned Contingent Worker status by Guidehouse.

I hold Bachelors and Master's degrees in Electric Power Engineering from Rensselaer Polytechnic Institute and am a registered Professional Engineer in Vermont, specializing in electrical engineering. I am a member of the Institute of Electrical and Electronics Engineers ("IEEE") and previously was a Section Chair in the State of Vermont. I have been responsible for numerous technical and economic studies of electric supply and reliability for investor-owned, municipal, and cooperative electric utilities throughout North America and worldwide. My experience includes evaluation of electric system reliability, distribution system planning and design, electric operations, and capital planning. As it relates to Kentucky Power's rate filing, I have testified before state utility commissions on electric reliability, distribution system planning, system design, emergency storm response, and the approval of capital projects proposed for inclusion in electric rates. I previously was employed by Green Mountain Power in various positions of increasing responsibility, including Director of Engineering and Operations, where I was responsible for the planning, design, and operation of the Company's generation, transmission, and distribution systems. My qualifications and previous appearances before regulatory agencies appear in more detail in Exhibit No. ELS 1.

Guidehouse regularly consults for electric investor-owned, municipal, and cooperative utilities in addition to state and federal agencies. As a matter of practice, Guidehouse is committed to maintaining an independent and unbiased approach to its engagements.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY PUBLIC SERVICE OR UTILITY REGULATORY COMMISSION?

A. Yes, I have testified as an expert witness in retail rate filings that addressed reliability and proposed investments in several other jurisdictions throughout North American including, Vermont, Montana, Nevada, Ontario. I have also testified as an expert witness before the Federal Energy Regulatory Commission to support Open Access Transmission Tariff filings on behalf of utilities in Montana, Indiana, New Mexico, and Florida. I have also testified on other matters involving electric reliability in Illinois, Colorado, and Arizona. The full list of appearances is presented in Exhibit ELS-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY?

A. My testimony addresses issues raised in data requests submitted by Commission Staff related to Kentucky Power's reliability performance and investments and that appropriate levels of investment has been made over the past several years.[3] Specially, my testimony provides compelling evidence that Kentucky Power's,

1. Reliability performance is consistent with those of a peer group of electric utilities with comparable service territory characteristics and distribution system attributes. However, additional spending in areas outlined in Kentucky Power's Proposed Distribution Reliability Rider ("DRR") and confirmed by pilot program results is needed to achieve its goal to improve reliability;

[3] See, for example data request nos. KPSC 2-19, KPSC 2-26, KPSC 3-19, KPSC 3-21, Walmart 1-11, AG-KIUC 2-15.

2. Prior levels of investment is consistent with those of the peer group, which is notable as Kentucky Power's electricity demand and number of customers served has declined over the past 10 years;
3. Level of spending on maintenance exceeds those of the peer utility group, particularly for vegetation management. However, as noted above, additional spending is needed to improve reliability;
4. Distribution system capacity planning and design standards are consistent with good utility practices, with appropriate levels of investment given electricity demand;
5. Distribution equipment maintenance practices and inspection intervals are consistent with good electric utility practice;
6. Proactive efforts to reduce customer interruptions caused by trees outside of the right-of-way ("TOR") is a practice that, subject to Commission approval of the proposed DRR, will further improve reliability performance;
7. Proactive efforts to further improve reliability from DRR investments targeting equipment replacements and distribution automation is consistent with good utility practice; and
8. Emergency (Storm) restoration processes and procedures, and the implementation of these procedures is consistent with good utility practice, resulting in restoration times that rival those of electric utilities encountering similar storms to those experienced in Kentucky.

The findings and conclusions listed above are supported by Guidehouse's comprehensive benchmarking analysis of Kentucky Power's reliability performance, planning and design, prior investments, vegetation management, restoration procedures, and benefits of proposed investments via the DRR. A report attached as Exhibit ELS- 2, *Independent Review & Assessment of Kentucky Power's Distribution Reliability Performance and Investments* supports my testimony and was prepared by myself with assistance from Guidehouse staff and an outside consulting firm working under my direction.[4]

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony addresses each of the eight topics listed above, sequentially, with evidence and rationale supporting conclusions I have reached based on the results of my analysis. First, I present the approach used to select a peer group of utilities to benchmark Kentucky Power's reliability performance, engineering standards and costs (*i.e.*, spending on distribution system investments and maintenance expense). I then describe the methods and sources I relied upon to support my findings and conclusions. Where applicable, I provide direct evidence in the form of charts and tables to further explain how I reached my conclusions.

III. ANALYTICAL APPROACH AND BENCHMARKING

Q. WHAT APPROACH DID YOU FOLLOW TO CONDUCT YOUR REVIEW OF KENTUCKY POWER'S RELIABILITY PERFORMANCE AND DISTRIBUTION SYSTEM INVESTMENTS?

A. My review and assessment were conducted via a comprehensive analysis of Kentucky Power's planning and design, investment levels and reliability performance. It utilizes a comprehensive data set, in some cases up to 15 years of data, obtained from Kentucky Power for each the areas listed below followed by a benchmarking of key performance and

[4] First Quartile Consulting provided electric benchmark data for several investment, performance and spending categories presented in my testimony and Guidehouse report.

cost metrics to those of peer group electric utilities with comparable service territory characteristics such as number of customers served and tree density.[5] It further relies on interviews I, along with Guidehouse subject matter experts, conducted with Kentucky Power personnel responsible for each area reviewed and benchmarked. Figure 1 lists the specific areas I reviewed and analyzed to address the topics listed in Section II.

Figure 1

Topics Assessed	Description
Benchmarking	Reliability metrics (SAIDI, SAIFI, CMI), spending (capital and maintenance)
Economic Growth	Historical and forecasted load and customer growth / contraction
Vegetation Management	Distribution vegetation standard, planned and completed work
Capacity Plans	Substation and feeder capacity, peak loads, and historical investments
Maintenance	Substation and distribution line maintenance, planned and completed
Engineering Standards	Distribution planning and design, and loading practices
Reliability Programs	Description and investment level of each reliability program
Grid Modernization	Description of program; planned and actual spending per year
Emergency Response	Incident Command Structure, mutual aid, and pre-planning
Storm Restoration	Customer restoration times and costs

Q. PRIOR TO EXPLAINING HOW YOU SELECTED A PEER GROUP OF ELECTRIC UTILITIES FOR BENCHMARKING RELIABILITY PERFORMANCE AND COSTS, PLEASE DESCRIBE HOW YOU CHARACTERIZE KENTUCKY POWER'S DISTRIBUTION SYSTEM.

A. Kentucky Power's distribution system is one that is comprised of long distribution lines serving low density load (*i.e.*, fewer customers per distribution line mile). Many circuits

[5] Certain cost and performance data was available for fewer than 15 years.

originating from Kentucky Power substations are rated 34.5kV with an average length exceeding 50 miles. Other Kentucky Power witnesses informed the Commission that many of its lines rated 34.5kV were constructed to serve remote mining load, several of which we have been informed are no longer operating. The departure of mining operations and decline in customers served over the past ten years likely has obviated the need for major capacity-related investments for load growth, which I address later in my testimony. Unlike other Investor Owned Utilities ("IOUs") in Kentucky, Kentucky Power does not serve major urban centers, which is one of the factors I considered in selecting a peer utility group for benchmarking reliability and costs. Lastly, Kentucky Power's distribution system is located in areas with very high tree coverage, with mountainous and difficult to access terrain. Collectively, each of these findings and observations create challenges when viewed in context with reliability performance. For example, the amount of damage and number of outages caused by trees during wind or ice storms and repairs can be more extensive than utilities with lower tree density.

Q. WHAT SOURCES DID YOU RELY ON TO IDENTIFY RELIABILITY PERFORMANCE AND COSTS OF THE BENCHMARKED UTILITIES?

A. I relied upon several sources to obtain data needed to accurately compare Kentucky Power's reliability and costs, including the U.S. Energy Information Agency for reliability statistics, FERC Form 1 for IOU capital costs and operation and maintenance expense ("O&M"), the U.S. Department of Agriculture ("USDA") Forest Service for state-level tree coverage, Integrated Resource Plans and 10K reports for distribution system data, utility web sites for various combinations of the preceding data and published reports.

Guidehouse also engaged First Quartile[6] consulting to provide maintenance and storm restoration benchmarks to supplement reliability and cost data obtained from the sources cited above.

Q. PLEASE DESCRIBE HOW YOU SELECTED A PEER GROUP OF UTILITIES FOR BENCHMARKING RELIABILITY PERFORMANCE AND COSTS.

A. The peer utility group includes IOU and Rural Electric Cooperatives ("RECs") with comparable service territories as measured by the relative number of customers served and tree coverage. Tree coverage was the primary selection criteria as the majority of Kentucky Power's customer interruptions are due to tree-related causes. The selection process and vetting of candidate utilities ensure peer group distribution system properties and characteristics align with Kentucky Power's distribution system. First, 61 utilities located in states with a high tree coverage and that reported reliability indices were chosen as candidate peer group utilities.[7] From this initial list, 19 municipal and four IOUs serving large urban areas were excluded; again, Kentucky Power serves predominantly rural areas. Next, of the remaining utilities, 15 were excluded because tree coverage in their respective service territories was below the established peer group threshold of 85 percent (Kentucky Power has tree coverage of 99%). Lastly, of the remaining 23 utilities, two were excluded because they serve less than 10,000 customers, leaving a net peer group of 21 utilities, including Kentucky Power.

---

[6] First Quartile obtains and reports benchmark data on a confidential basis, with the identify of individual utilities hidden in charts and tables to maintain confidentiality.

[7] Five states were selected, including Kentucky, West Virginia, Vermont, New Hampshire, Maine, and Louisiana.

Q. WHY DID YOU INCLUDE RURAL ELECTRIC COOPERATIVES IN THE PEER UTILITY GROUP?

A. Since RECs serve rural areas, which often have high tree coverage, their distribution systems often are most comparable to Kentucky Power's distribution system. Further, only RECs that report reliability indices (along with the IOUs) were compared to those reported to the Commission by Kentucky Power.[8]

IV. RELIABILITY PERFORMANCE

Q. HOW DOES KENTUCKY POWER'S RELIABILITY PERFORMANCE COMPARE TO THE PEER GROUP?

A. Kentucky Power's reliability as measured by average SAIFI[9] for normal weather events (*i.e.*, non-MED[10]) over the past 10 years compares favorably to the peer group average. Figure 2 presents Kentucky Power's average SAIFI versus the other 20 peer group utilities. I view SAIFI as a better measure of reliability performance as it indicates how many customers, on average, have experienced interruptions. It is also indicative of the capability of the utility's distribution system to withstand events that may cause interruptions. This is because SAIFI quantifies how often events cause distribution lines and equipment to fail or otherwise require protective devices to operate to minimize damage caused by external events such as tree contact. It also contradicts claims that Kentucky Power has not sufficiently invested in its distribution system. Outage duration, as measured by SAIDI,

---

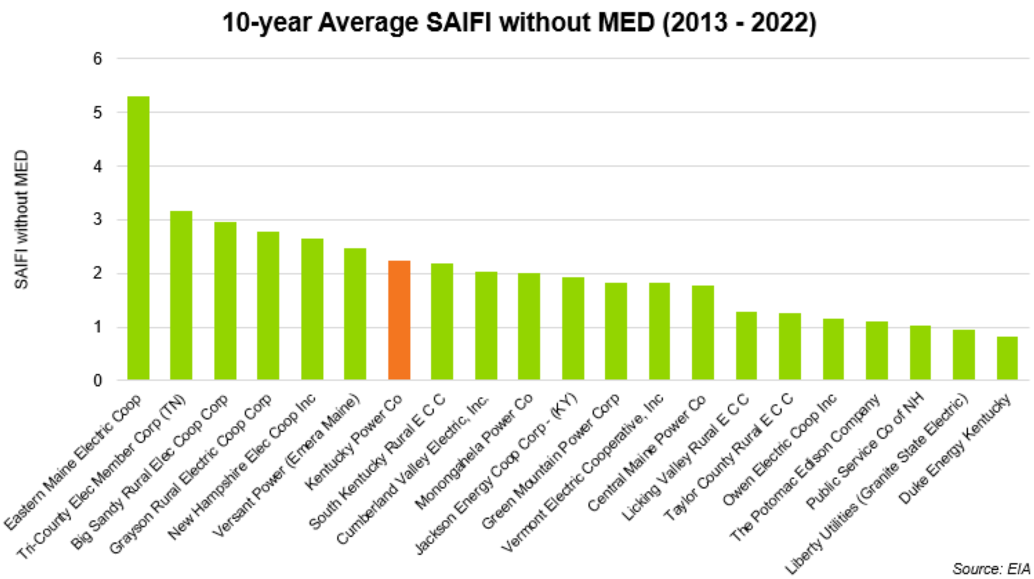
[8] Unlike IOUs, which report costs in FERC Form 1 reports, RECs typically do not report cost data via published reports or on their web sites.

[9] System average interruption frequency index.

[10] Major Event Day, as defined in IEEE P1366 standard. MED's include storms and other events that are significantly above average of most recorded interruptions and derived using a logarithmic statistical analysis.

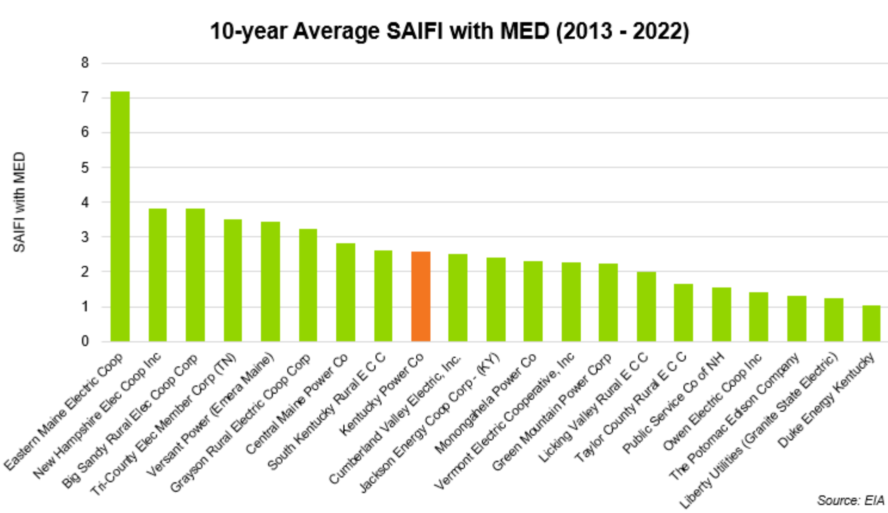
indicates how long it takes, on average, to restore service to customers following an event that causes an interruption of service; but it should not be used to assess the capability of distribution lines and equipment to withstand storms and abnormal events.

Figure 2



When all customer interruptions are counted, including Major Event Day ("MEDs"), Kentucky Power's reliability indices for non-MED SAIFI are near the peer group average. Figure 3 presents SAIFI indices for the peer group with MEDs included.

Figure 3



Q. HOW DOES KENTUCKY POWER'S RELIABILITY COMPARE TO THE PEER GROUP AVERAGE FOR OUTAGE DURATION?

A. The length of time Kentucky Power required to restore electric service to customers as measured by SAIDI[11] is above the peer group average. Figure 4 presents Kentucky Power's non-MED SAIDI over the past 10 years.

Figure 4

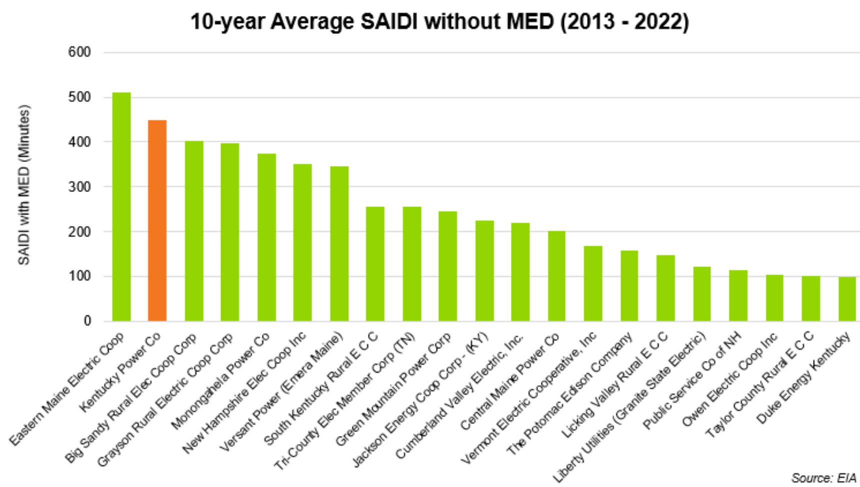
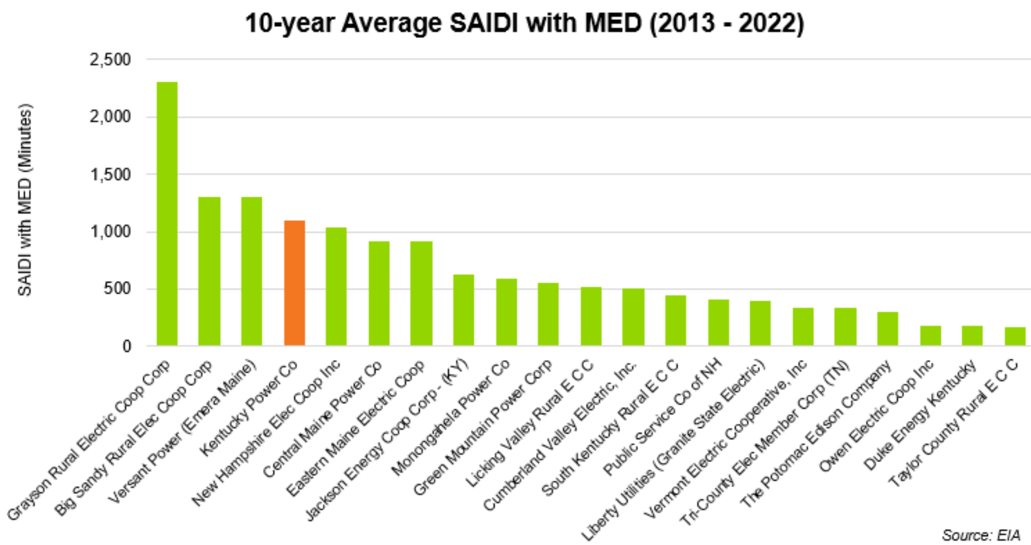


Figure 5 indicates Kentucky Power's reliability performance as measured by SAIDI when MED is included improves when compared to non-MED performance for the peer group average. While the improvement in MED SAIDI is modest, results confirm that Kentucky Power's distribution system is as resilient as those of the peer group during major storm events. As mentioned earlier in my testimony, Kentucky Power's tree coverage is among the highest in the peer group. Given the dominance of tree-related outages during major events such as continuous high winds, snow and ice storms, coupled with the length of time required by utility crews to traverse long distribution circuits, Kentucky Power's reliability performance as measured by SAIDI should not be considered exceptionally high. However,

[11] System average interruption duration index.

given Kentucky Power's goal to reduce SAIDI, its proposal to widen distribution ROWs via the proposed TOR program should serve to reduce SAIDI during MEDs.

Figure 5



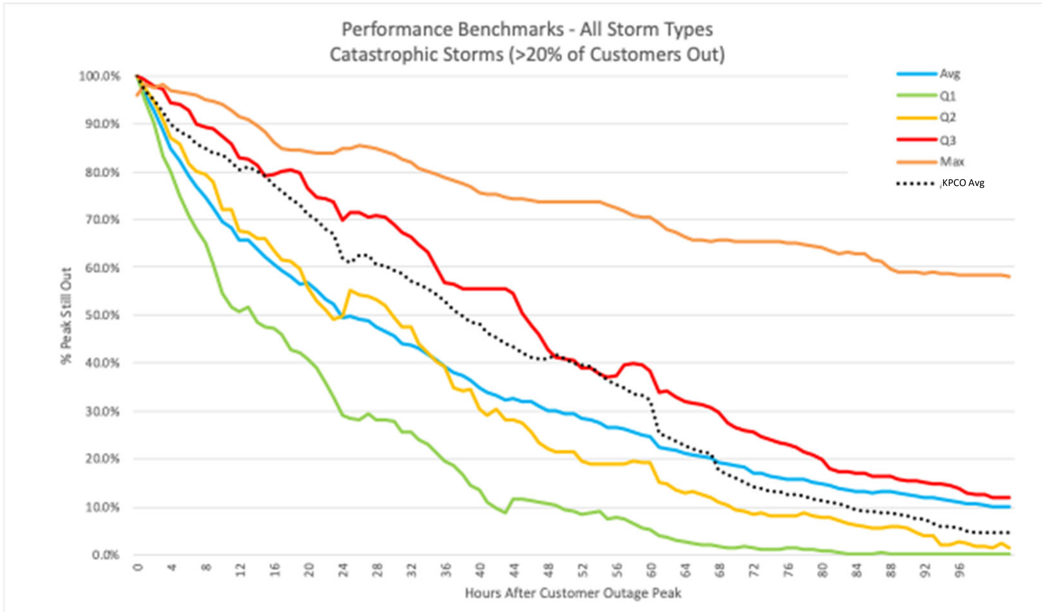
Q. ARE THERE OTHER FACTORS THAT SHOULD BE CONSIDERED WHEN COMPARING KENTUCKY POWER'S RELIABILITY PERFORMANCE TO THE UTILITY PEER GROUP?

A. Yes. Kentucky Power, like other utilities in the state, includes planned outages when reporting reliability performance (e.g., SAIFI and SAIDI) to the Commission. In contrast, my experience indicates that many utilities exclude planned outages when reporting reliability indices, consistent with IEEE P1366 guidelines. The reliability indices I obtained for the peer group utility were obtained from a U.S. Energy Information Agency database that is intended to exclude planned events. However, I was unable to determine if any of the peer group utilities exclude planned outages. However, by removing planned outages, Kentucky Power's reported values for customer interruptions is 15 percent lower and customer minutes of interruption is lower by 11 percent; each of which would improve benchmark performance compared to the peer group average if other utilities excluded planned outages in their reliability reporting.

Q. MOVING TO RESTORATION PERFORMANCE DURING MAJOR STORM EVENTS, HOW DOES KENTUCKY POWER CUSTOMER RESTORATION TIMES COMPARE TO OTHER UTILITIES?

A. Once storms have caused the greatest impact and the maximum number of customers have lost service, Kentucky Power's ability to restore service to these customers compares favorably to utility benchmarks. Figure 6 compares Kentucky Power's percent restoration to the First Quartile benchmark utility group for major storm events; *i.e.*, in this instance, those interrupting more than 20 percent of the utilities' customers. The percentage of Kentucky Power's customers remaining with service restoration pending, as measured on an hourly basis, is just above the benchmark average and consistently below the performance of the benchmark utility group in the third quartile. Each quartile represents the average percentage of customers restored following the interval when the maximum number of customers were interrupted, with Quartile 1 as the benchmark group with the fastest restoration and Quartile 4, the slowest. The curve for Kentucky Power will move closer to the average (*i.e.,* to the left) following the implementation of the Distribution Automation [and] Circuit Reconfiguration ("DACR") component of the DRR, as the number of customers interrupted by distribution outage events will be reduced.

Figure 6



I view these results favorably, as Kentucky Power's distribution system is comprised of long distribution lines serving, on average, a lower number of customers – approximately 16 customers per mile as per Mr. Phillips' direct testimony – compared to the benchmark utilities, which collectively average 45 customers per circuit mile. Similarly, Mr. Phillips cites other Kentucky IOUs as having between 34 to 65 customers per distribution line mile.[12] Further, it is likely that the very high tree density of Kentucky Power's distribution system – 99 percent tree coverage is cited earlier in my testimony – causes a greater amount of damage from falling trees and limbs and requires more follow-up repairs compared to other utilities with less tree coverage.

[12] Everett Phillips prefiled testimony, p. 16, lines 22-23 and p. 17, line 1.

V. DISTRIBUTION INVESTMENTS AND RELIABILITY IMPROVEMENTS

Q. WHAT MEASURES HAS KENTUCKY POWER UNDERTAKEN TO ADDRESS THE NUMBER AND DURATION OF OUTAGES ON ITS DISTRIBUTION SYSTEM?

A. Kentucky Power has undertaken steps to improve reliability by targeting investments on circuits and equipment most prone to failures. Key among these is a program to formalize vegetation management activities to include the removal of at-risk trees located outside its distribution rights-of-ways ("TOR"). A pilot program implemented in 2018 resulted in a 15 percent reduction in TOR-related interruptions, an important result given that nearly 50 percent of customer interruptions, as measured by customer minutes of interruptions ("CMI"), are caused by trees located outside the distribution rights-of-way ("ROW"). It is also the impetus behind Kentucky Power's decision to pursue full implementation of the TOR program by investing $12 million annually over the next five years as proposed in its Distribution Reliability Rider ("DRR").

As part of its Distribution Asset Management program, which is part of Kentucky Power's Distribution Reliability programs, Kentucky Power has also replaced significant quantities of defective fused cutouts and porcelain insulators over the past several years, as these are the two leading causes of equipment failure as measured by CMI. Other at-risk or defective equipment identified in bi-annual inspections are repaired or removed on a prioritized basis. Kentucky Power has modernized its distribution system via the installation of fault detection and automatic transfer schemes via its DACR program[13] to reduce the number of customers interrupted by outages and to lower the time needed to

[13] Also referred to as Fault Location, Identification, and Service Restoration or FLISR.

needed to repair the fault. Kentucky Power proposes to build upon successes achieved by each of the above initiatives by investing funds, incrementally, in each of the areas described above over the next five years as proposed in its DRR.

Lastly, Kentucky Power in 2014 adopted the National Electric Safety Code ("NESC") heavy loading design standard,[14] which is applied on a selective basis, as not all existing distribution line segments are suitable candidates for the heavy loading standard nor is Kentucky Power required to build to the heavy loading design standard; *i.e.*, mid-span pole installations may not be practicable in some locations so the medium design standard is appropriate in this example. Over time, as the Company continues to selectively upgrade its distribution system to NESC heavy loading, I expect the adoption of this design standard will further improve system reliability and resiliency during major storm events.

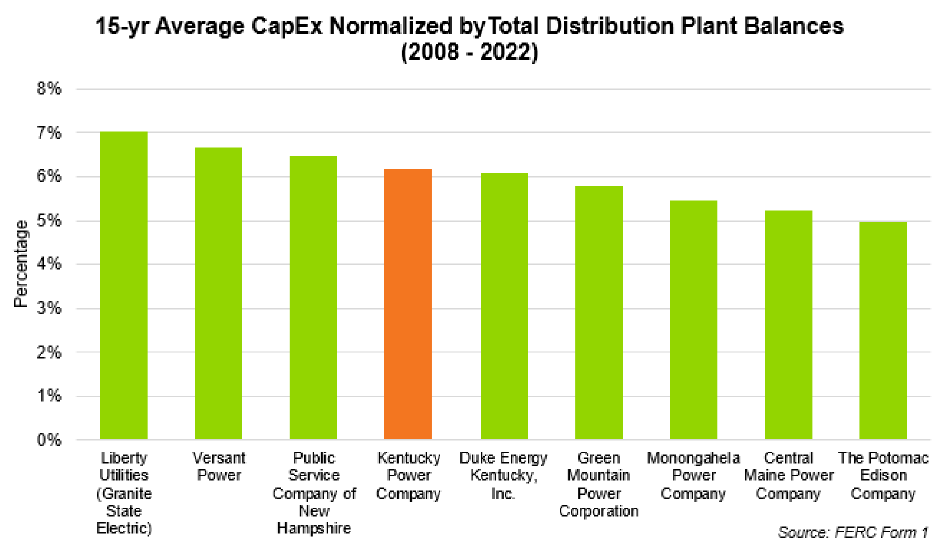
Taken together, the above measures that Kentucky Power has undertaken over the past several years demonstrate that it has proactively and responsibly addressed reliability performance and made appropriate investments to reduce both the number and duration of customer interruptions. Commission approval of the incremental investments Kentucky Power proposes in its DRR will build upon these prior efforts.

[14] Kentucky Power's service territory is located in a medium loading design standard per NESC regional maps.

Q. YOU MENTION IN YOUR ANSWER TO THE PRIOR QUESTION THAT KENTUCKY POWER HAS MADE AN APPROPRIATE LEVEL OF INVESTMENT IN ITS SYSTEM. WHAT EVIDENCE DO YOU HAVE TO CONFIRM THIS STATEMENT?

A. In addition to reliability, I compared Kentucky Power's spending on capital investments and maintenance expense to the IOU segment of the peer utility group using costs reported in their annual FERC Form 1 for the past 10 years.[15] For capital investments, I compared the 15-year average of the annual summation distribution plant additions for FERC distribution accounts 360 through 374 to total original plant balances for Kentucky Power to values derived for the IOU peer group. Figure 7 confirms Kentucky Power's annual distribution investments as a percent of total distribution plant balances over the past 15 years is within the peer group average.

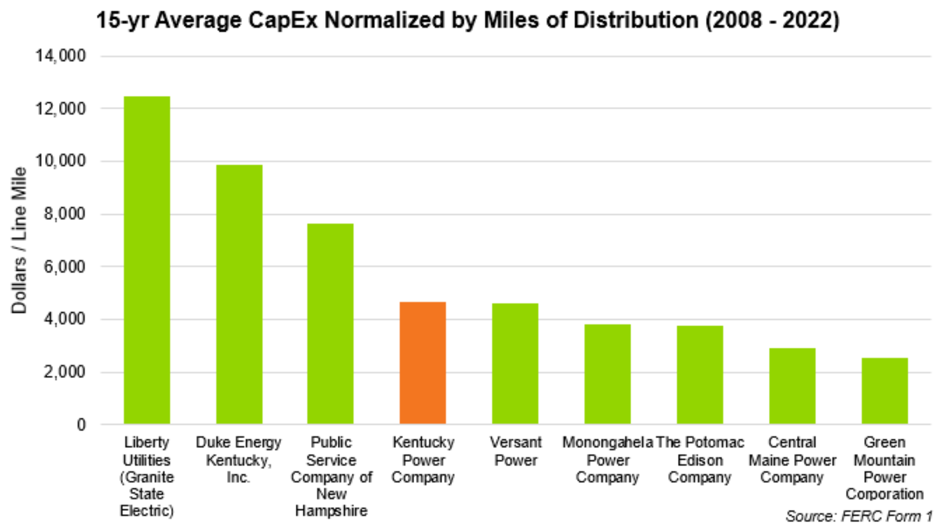
Figure 7



[15] The RECs do not prepare and submit FERC Form 1 and do not present costs via publicly available documents, and therefore, were excluded from peer group for cost benchmarks.

I also compared Kentucky Power's 15-year average annual distribution investments divided by total customers served to those of the IOU peer group. Figure 8 confirms results derived per customer served are similar to those derived using original distribution plant balances.

Figure 8

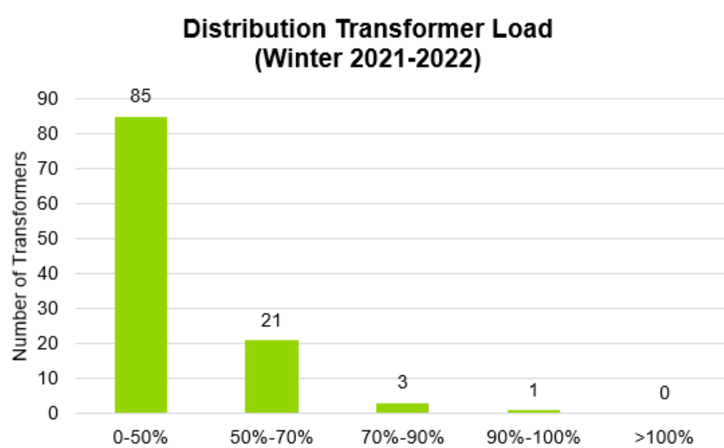


The conclusion I draw from these findings is that Kentucky Power's investment in its distribution system is on par with peer group IOUs with comparable distribution systems. My conclusion is further supported by the lower level of investment Kentucky Power needed solely for load growth – new substations and circuits are proposed in the DRR to improve reliability via enhanced feeder ties and load transfer capability. The number of customers served by Kentucky Power has declined by about 8,000 customers (almost a five percent reduction) while electric peak demand has dropped by almost 400 MW from its prior high of 1,400 MW in 2014. Accordingly, the amounts Kentucky Power needed to invest for capacity and customer growth alone were lower than other utilities in the peer group Thus, if values in the above chart were normalized to account for load growth, Kentucky Power's spending likely would appear even more favorable when compared to the peer utilities. However, because spending for new capacity in the past has been low does not preclude the need for addition investments proposed via the DRR to improve reliability.

Q. IN YOUR RESPONSE TO THE PRIOR QUESTION, YOU INDICATED THAT KENTUCKY POWER HAS REDUCED ITS SPENDING ON CAPACITY-RELATED INVESTMENTS. HAS THIS REDUCTION CAUSED EQUIPMENT TO BECOME OVERLOADED, RESULTING IN CUSTOMER INTERRUPTIONS?

A. No. Figure 9 presents substation transformer loadings as a percent of maximum rating as of winter 2022, grouped by loading intervals from less than 50 percent loaded to over 100 percent loaded.[16] Most transformers are well below their maximum rating, and none are above 100 percent. Comparable results were obtained for distribution circuits. Further, customer interruptions reported in Kentucky Power's reliability records, due to overloads, are near zero, thus confirming that it has not under-invested in substation or circuit capacity.

Figure 9

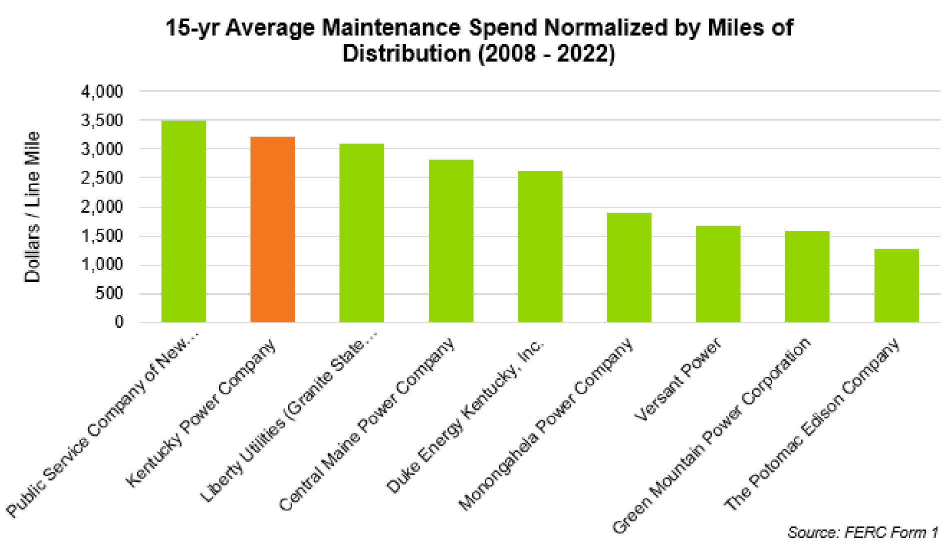


[16] Kentucky Power's peak demand occurs during winter months.

Q. IN TERMS OF MAINTENANCE, ARE KENTUCKY POWER'S EXPENSES ON MAINTENANCE SUFFICIENT TO ENSURE RELIABLE OPERATION OF ITS LINES AND EQUIPMENT?

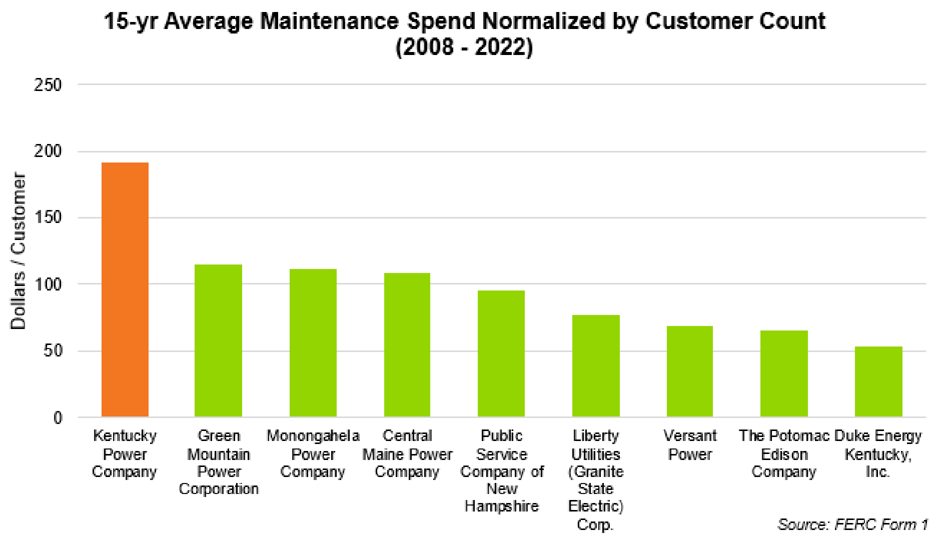
A. Yes. First, as I explain in the following section, Kentucky Power's maintenance programs and practices are consistent with good utility practice. I also compared the amounts Kentucky Power has spent on maintenance to those of the IOUs in the peer group over the last 15 years. Figure 10 indicates Kentucky Power's spending on maintenance per miles of distribution lines was above the peer group average. This finding is particularly notable as the average miles of line on Kentucky Power's distribution circuits is high, averaging over 50 miles for circuits rated 34.5kV.

Figure 10



I also compared the amounts Kentucky Power spent on maintenance on a per customer basis during the same time period. Figure 11 confirms the amounts Kentucky Power spends on maintenance is highest among the IOU peer group when calculated using the number of customers as the denominator. This finding is not unusual or unexpected, as the low customer density on Kentucky Power's distribution system invariably causes a further shift or spending on maintenance to the highest among the peer group.

Figure 11



The above results contradict suggestions or claims that Kentucky Power has underspent on distribution maintenance, particularly for vegetation management. The majority of the amount Kentucky Power spent was for ROW maintenance, mostly to maintain clearances for trees located within the distribution ROW. Kentucky Power's proposal to modestly increase the O&M for Trees within the ROW (TIR) ensures an appropriate level of spending is targeted to circuits most susceptible to tree-related interruptions.

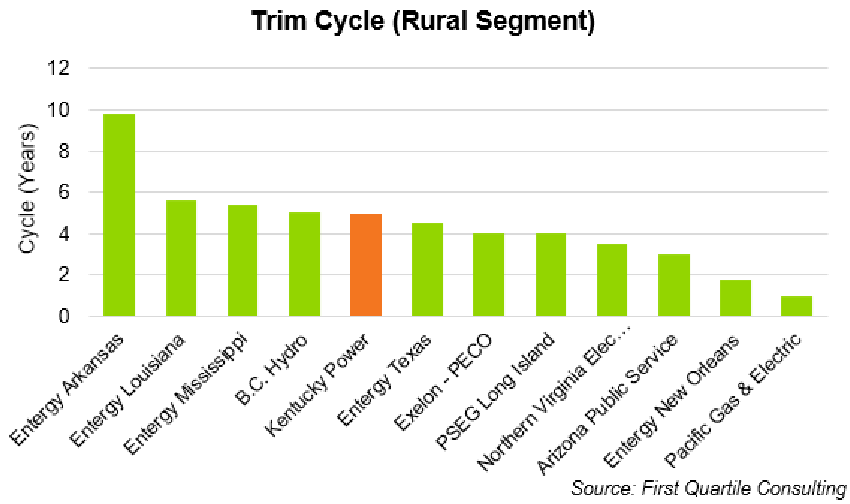
From a capital perspective and related to vegetation management, Kentucky Power also removes trees from outside of the ROW (TOR). Due to the fact that TOR alone causes almost 50 percent of total customer interruptions, Kentucky Power needs to increase spending on its TOR program to improve reliability as measured by SAIDI to meet Kentucky Power's reliability objectives.

VI. MAINTENANCE PRACTICES

Q. YOU INDICATE IN THE PREVIOUS SECTION THAT KENTUCKY POWER SPENDS APPROPRIATE AMOUNTS ON DISTRIBUTION MAINTENANCE. CAN YOU CONFIRM MAINTENANCE PRACTICES ARE CONSISTENT WITH GOOD UTILITY PRACTICE AND COMPLETED ON SCHEDULE?

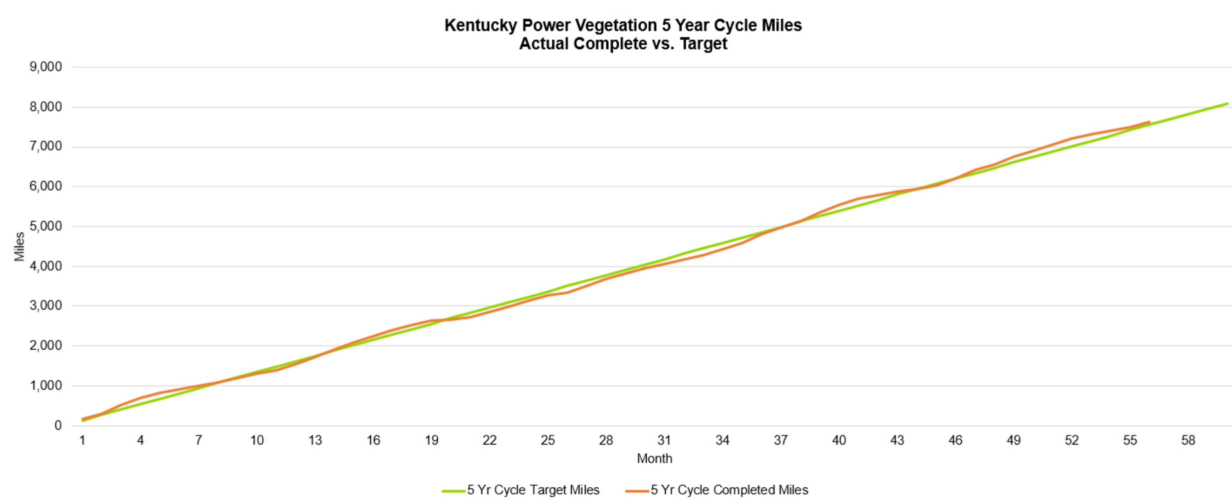
A. Yes. First, I address vegetation management, by far the largest component of Kentucky Power's distribution operation and maintenance (O&M) expense. I reviewed Kentucky Power vegetation management policies and procedures, including clearances, versus those of other utilities where I have conducted similar assessments. From my assessment, I can conclude that Kentucky Power's vegetation management program is consistent with good utility practices and comparable to those deployed by electric utilities with a high concentration of trees. The detailed specifications and requirements of contractors outlined in these procedures is thorough. The specification of minimum clearances by tree species is consistent with good industry practice, as is the removal of trees at risk of falling onto circuits from outside the distribution ROW. Kentucky Power's five-year cycle is also consistent with good utility practice. Figure 12 confirms Kentucky Power's five-year trim cycle is consistent with the First Quartile benchmark utility group for distribution circuits located in rural areas.

Figure 12



Equally important to Kentucky Power's vegetation management practices is its ability to meet trimming cycles on time. Figure 13 shows minimal variance between scheduled and completed tree trimming, thus confirming that Kentucky Power judiciously tracks and maintains trimming clearances in accordance with schedules.

Figure 13



Q. PLEASE ADDRESS KENTUCKY POWER'S MAINTENANCE PRACTICES FOR DISTRIBUTION CIRCUITS AND SUBSTATIONS.

A. Starting with distribution circuits, Kentucky Power complies with the Commission's 2-year inspection guidelines as outlined in Exhibit ELS-2. I view the two-year inspection cycle and inspection guidelines as a good practice, as my experience indicates, other utilities have longer inspection cycles or conduct them more sporadically. Kentucky Power also provided evidence that inspections are completed on time, with follow up action taken to address deficiencies on a prioritized basis. Figure 14 confirms that the number of devices Kentucky Power inspected over the past 15 years has been completed on time with minimal variance for most years, except for 2020 through 2022 when Covid-19 impacted utility work plans and schedules.

Figure 14

	Switched Cap		Fixed Cap	Recloser Electronic		Recloser Hydraulic		Regulator
Year	No. Inspections Completed	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices Inspected	No. Inspections Completed
2008	147	91	347	259	2017	1140	550	291
2009	268	84	391	292	1879	1084	607	316
2010	303	76	395	289	1928	1109	583	307
2011	327	88	437	311	1900	1097	611	323
2012	316	80	457	327	1816	1075	641	333
2013	299	74	490	353	1854	1055	618	319
2014	296	72	516	369	2079	1169	630	326
2015	283	71	533	392	1009	604	631	327
2016	278	69	552	414	1879	1066	619	319
2017	267	63	562	423	1567	875	626	326
2018	241	59	565	432	1317	746	595	304
2019	247	58	602	458	1387	742	624	322
2020	224	56	630	479	1926	1076	618	317
2021	80	42	646	512	988	541	471	236
2022	13	20	655	530	1423	767	439	227
2023	11	22	375	300	433	250	133	75
Total	**3827**	**1165**	**8773**	**6140**	**29160**	**14396**	**9968**	**5163**

Kentucky Power's pole inspection program, normally conducted on a 10-year cycle for poles exceeding an age threshold, is consistent with good utility practice, with inspection results for the five-year period between 2014 and 2018 presented in Figure 15 indicating a low percentage of poles, just over two percent, needing replacement due to loss of strength.

Figure 15

Inspection Results	Quantities
Non-Reject	32,448
Non-Restorable Reject	527
Priority Non-Restorable Reject	379
Priority Restorable Reject	611
Restorable Reject	284
Unset	1
Total	**34,250**

Kentucky Power's maintenance practices and policies for substation equipment are equally comprehensive as those followed for distribution circuits. Kentucky Power substation equipment maintenance is based on an AEP system-wide standard, which I reviewed and found to be comprehensive and consistent with those I have encountered in similar reviews for utilities throughout the U.S.[17] Importantly, each procedure recognizes differences in equipment type, manufacturer, design, testing requirements and other factors specific or unique to the device inspected or maintained. For example, power transformer maintenance schedule varies according to factors such as equipment supplier, core design, voltage, and other device-specific attributes.

Figure 16 confirms that Kentucky Power's equipment maintenance schedules conform to good industry practice. Further, Kentucky Power provided evidence via electronic records[18] that distribution maintenance, both line and substation, is performed as scheduled.

[17] Substation equipment maintenance is performed by the Transmission Field Services group.
[18] Kentucky Power collects and reports data in electronic format to ensure consistent reporting and a sole source for data capture.

Figure 16

Substation Maintenance Cycles	Average Cycle Time (12 Utilities)	Kentucky Power	Kentucky Power Comments
Power Transformers	5.1	4/5/8/10	Varies by transformer type
Relays	5.6	--	Follows NERC compliance
DC Supply (Batteries)	N/A	1	Annual detailed inspection
Circuit Breakers	5.6	6	For most breaker types

VII. SUMMARY ASSESSMENT

Q. PLEASE SUMMARIZE YOUR INDEPENDENT ASSESSMENT OF KENTUCKY POWER'S DISTRIBUTION SYSTEM RELIABILITY AND COSTS.

A. From the evidence I obtained via my analysis of Kentucky Power's reliability history for normal and major storms, I determined that reliability performance over the past 10 years is comparable to those of a peer group of electric utilities with similar service territories, as my selection of a peer group focused on those with similar tree coverage. While Kentucky Power's reported reliability indices are above those of larger utilities in Kentucky that serve urban load, differences in distribution circuit length, tree coverage and customer density are key factors that should be considered when comparing reliability performance. Kentucky Power's distribution system has longer lines, lower customer density and higher tree coverage, each of which are contributing factors to reliability performance. Kentucky Power's spending on capital and maintenance, particularly for vegetation management, is at or above those of the utility peer group and suggestions or claims that Kentucky Power has under-investing in its distribution system are unfounded and not based on the evidence I relied upon to support my findings and conclusions. The fact that Kentucky Power's spending on capital and maintenance is within the peer group average is notable given the decline in customers and electricity demand over the past 10 years. Despite the above, proposed incremental spending outlined in the DRR is needed to improve reliability as measured by SAIDI and CMI.

Kentucky Power historically has targeted spending in areas with the greatest reliability benefits, and proposes to build upon these past efforts to further improve reliability via its proposed DRR. Each of the findings cited above supports my conclusion that Kentucky Power has operated and maintained its distribution system in a responsible manner, with appropriate levels of investment to ensure safe and reliable electric service to its customers. Kentucky Power recognizes the need to further improve distribution reliability and has proposed spending via its DRR to achieve this objective.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Eugene L. Shlatz

Contractor – Contingent Worker

eshlatz@guidehouse.com
Direct: 802.233.1890

Professional Summary

Gene has over 35 years of management consulting and supervisory experience in energy delivery, power generation and distributed energy systems. In his prior role as a Director at Guidehouse, he directed engagements on electric system reliability, renewable technologies, microgrids, asset management, electric pricing, due diligence and system adequacy. His clients included US, Canadian, European and South American electric utilities, electricity consumers, law firms and government agencies. Gene is an expert on electric power delivery systems; and has testified before FERC, state commissions and the U.S. Congress on transmission open access, DG integration, retail rates, compliance, and capital planning. He has published numerous articles and industry presentations on smart grid, distributed resources, electric reliability, energy efficiency, and electric pricing.

Professional Experience

In Gene's prior role as a Director at Guidehouse, he directed project teams and managed consulting engagements for electric utility, government and energy supply clients. He was responsible for and continues to support energy delivery and power production engagements in the following areas:

- **Regulatory/Legal** – capital planning, transmission and distribution program support, renewables integration and pricing, expert witness for state and federal agencies, and civil litigation
- **Operations & Planning** – transmission and distribution performance evaluation; reliability, target setting, remediation analysis, and service quality standards
- **Emerging Technologies** – renewable technology and smart grid integration, energy efficiency and technical/economic assessment of distributed resources
- **Asset Management** – implementation strategy, project prioritization, performance measurement, utilization and cost optimization, electric delivery system planning

Representative Client List and Engagements

Distributed Energy Resources & Advanced Technologies

- **American Electric Power.** Program lead to assess DER integration strategies and cost for a multi-state solar PV and electric vehicle forecast. Developed analytical approach to predict system impacts and mitigation options to address distribution system performance violations.
- **Aspen/California Energy Commission**. Conducted several independent reviews of advanced energy systems and applications for applicants seeking EPIC project funding. Technologies evaluated include integrated storage and renewables, advanced simulation software and Microgrids.
- **NYSERDA**. Evaluated impacts of small-scale energy storage on radial and network distribution systems to assess the applicability of standby rates adjustments for New York electric utilities.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

- **California Utility (Confidential)**. In response to recent fires in California, evaluated wildfire prevention mitigation strategies to reduce the hazard potential for electric transmission and distribution lines and equipment.
- **Dubai Electric and Water Authority.** Project lead for distribution automation, transmission automation, asset management, and renewables integration smart technology assessment. Conducted technical and economic studies of smart technology options and developed roadmap for implementation of recommended strategies.
- **California Energy Commission/Southern California Edison**. Project manager of DER integration studies for a major utility planning region. Predicted hosting capacity limits and options to increase DER capacity and value via advanced communications and control technologies. Assessed the capability of energy storage to increase capacity limits.
- **U.S. Department of Energy/Dominion Virginia Power.** Project manager of Solar Integration Study to identify renewable capacity impacts and integration requirements in the state of Virginia. Determined distribution hosting capacity limits and impacts of increasing amounts of solar on DVP's generation, transmission and distribution system.
- **Los Angeles Department of Water & Power.** Technical lead of a DER integration study to determine integration requirements and hosting capacity limits, and approaches to target DER and storage based on locational needs and benefits. Assessed communication and control strategies, organization structure, tariffs and rates, and strategies to achieve renewable portfolio targets.
- **Orange & Rockland Utilities.** Project manager of a DG Interconnection benchmarking analysis. Conducting studies to predict hosting capacity limits on O&R's T&D system and mitigation options in support of NY's Renewable Energy Vision initiative.
- **Pacific Gas & Electric Company.** Project manager of a Transmission and Distribution PV Impact Study. It included engineering analyses designed to facilitate the integration of DGPV into the grid. Developed PV values based on analysis across multiple scenarios and attributable to DGPV.
- **Major Southeastern U.S. Utility (Confidential).** Project manager of a Solar Integration Study to assess the technical and economic impact of increasing amounts of solar on the utilities' generation, transmission and distribution system.
- **California Energy Commission/Southern California Edison.** Project manager of a study evaluating DG impacts and integration requirements for up to 12,000 MW of DG in California by 2020. Developed a technical evaluation and costing framework applicable to all CA utilities.
- **U.S. Navy.** Evaluated on-site microgrid options for a major military shipyard, including technical assessment of renewable generation, control strategies, electric system performance and system upgrades required to operate in stand-alone and parallel modes of operation.
- **U.S. Department of Energy (DOE).** Provided technical and program management support for DOE's Smart Grid Investment Grant (SGIG) program. Responsible for impact evaluation of smart grid technologies, including program benefits and implementation strategies.
- **PowerStream (Ontario).** Provided project management and evaluation services for an on-site microgrid comprised of a mix of wind, solar, storage and gas-fired technologies. Developing control and dispatch strategies and methods for assessing MG performance and benefits.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

- **NV Energy.** Project manager of DG and large PV integration studies for southern and northern Nevada. Identified technical/capacity limits of renewable energy sources on NV Energy's T&D system. Responsible for technical and economic evaluation of power system impacts and integration costs, including intermittency. Testified before Nevada Commission to support findings.
- **Toronto Hydro.** Project manager of comprehensive evaluation of distributed energy resources versus traditional T&D alternatives for a major urban center. Included a technical assessment of DG systems impacts, technology integration and forecast of cost-effective alternatives.
- **Southern California Edison Company.** Technical support a 3-year integrated grid pilot designed to demonstrate modern grid infrastructure functionality and advance customers' ability to interconnect renewable energy sources, proactively manage customer demand, and improve the safety and reliability of the grid in a cost-effective manner.

Reliability, Benchmarking and Electric System Planning

- **Jersey Central Power & Light.** Principle investigator of a commission-mandated Operations Review of JCP&L's distribution system. The review included an assessment of reliability, storm response, preventative maintenance and budgeting processes. Navigant's report and recommendations were unanimously approved and accepted by the New Jersey Board of Public Utilities.
- **Exelon/Commonwealth Edison.** Lead consultant of an engineering and operational assessment of Exelon's system design, construction and maintenance practices. Our study was filed before the ICC in response to claims of system inadequacy for major storms. Provided expert witness testimony that confirmed ComEd's T&D practices were consistent with or exceeded industry standards
- **Government of Puerto Rico (Public Private Partnership).** Program oversight lead for long-term disaster recovery efforts for the Puerto Rico Electric Power Authority (PREPA) generation, transmission and distribution systems. Responsible for developing Grid Modernization plans to restore the electric grid to current standards, consistent with FEMA and BBA funding requirements.
- **Toronto Hydro (THESL).** Prepared an independent technical assessment of a proposed relocation of a major segment urban transmission and distribution system as evidence before a tribunal in the City of Toronto. Analyzed relocation options and impact on power system reliability and performance.
- **New York Power Authority/ Puerto Rico Electric Power Authority**. Lead investigator and subject matter expert of a study to assess damage caused by major hurricanes in 2017 and to provide recommendations to bring the power generation and delivery system to current design standards.
- **Hawaiian Electric Company**. Project manager of a technical analysis to assess the impact of capital and O&M improvement programs on electric system reliability performance during storms and major events. Demonstrated a correlation of program improvements and system resiliency during storms.
- **BC Hydro.** Lead investigator to benchmark and assess vegetation management practices and applications across the province of British Columbia. Provided recommendations on enhancing processes and VM methods to improve efficiency and cost.
- **Saskatoon Light & Power.** Project manager of a 20-year capital development plan designed to meet reliability and performance objectives at lowest cost. Our assessment included a review and analysis of T&D engineering, maintenance and operations; and recommendations for improvement.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

- **Sulphur Springs Valley Electric Cooperative (SSVEC).** Project manager of an independent Feasibility Study of delivery alternatives, including T&D, distributed generation, energy efficiency, energy storage and renewables. Successfully testified as an expert witness before AZ commission.
- **Austin Energy.** Performed a benchmarking and gap analysis of AE's engineering and operations. Prepared recommendations to enhance reliability and operations efficiency.
- **Saskatoon Light & Power.** Project manager of a 20-year capital development plan designed to meet reliability and performance objectives at lowest cost. Our assessment included a review and analysis of T&D engineering, maintenance and operations; including recommendations for improvement.
- **Toronto Hydro Electric System, Limited (THESL).** Performed a long-range planning study for THESL's radial and network downtown distribution system. Evaluated capital expansion versus CDM needed to serve downtown Toronto for 20 years.
- **Sulphur Springs Valley Electric Cooperative (SSVEC)**. Project manager of an independent Feasibility Study of delivery alternatives, including T&D, distributed generation, energy efficiency, energy storage and renewables. Successfully testified as an expert witness before AZ commission.
- **Austin Energy.** Performed a benchmarking and gap analysis of engineering and operations performance for AE's energy delivery organization.
- **Ameren Services.** Conducted a review and predictive assessment of distribution reliability. A methodology was developed to apply fact-based methods to allocate reliability expenditures.
- **American Electric Power.** Conducted a review and predictive assessment of distribution reliability. Applied fact-based methods to prioritize investment decisions and to quantify risk.
- **Potomac Electric Power Company (PHI).** Conducted an investigation and benchmarking of PEPCO's T&D system, including transmission and distribution infrastructure. Prepared recommendations to enhance performance and reduce outage risk.
- **National Grid.** Conducted a system review and predictive assessment of distribution reliability. A strategic methodology was developed to predict system outage performance based on system attributes, equipment performance and historical reliability.
- **Potomac Electric Power Company (PHI).** Project manager of a benchmarking analysis of PEPCO's T&D system, including transmission and distribution infrastructure. Prepared recommendations to enhance performance and reduce outage risk.
- **Dominion – Virginia Power**. Project manager and lead investigator of a comprehensive technical review and risk assessment of secondary networks. Reviewed and analyzed engineering standards, planning criteria, operations and maintenance, and construction methods.

Regulatory and Legal

- **Expert Witness - Civil Litigation (Various Jurisdictions).** Expert witness in personal injury cases involving electric utility assets. Conducted technical investigations, reviewed and submitted discovery, and declarations to support evidentiary hearings and agreements.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

- **Duke Energy (Florida), Public Service of New Mexico & El Paso Electric.** Conducted studies to determine ancillary service requirements costs. Provided expert testimony ancillary service schedules to support OATT fillings before the U.S. Federal Energy Regulatory Commission.
- **Hydro Ottawa (Ontario).** Conducted an independent review of Hydro Ottawa's asset management and Distribution System Plan to support a rate request filing before the Ontario Energy Board (OEB). Provided recommendations to ensure compliance with OEB filing requirements for capital investments.
- **NorthWestern Energy (FERC).** Expert witness supporting ancillary services schedules and pricing for a filling before the U.S. Federal Energy Regulatory Commission.
- **NorthWestern Energy (Montana/FERC).** Expert witness for NEM Solar Integration and NERC Reliability Performance studies to comply with Montana Public Service Commission and U.S. Federal Energy Regulatory Commission requirements. Conducted technical and economic studies of solar impacts on NorthWestern's service territory and submitted expert testimony to support findings on ancillary services before the MPSC.
- **International Business Machines (IBM).** Conducted a reliability assessment of issues related to the City of Boulder, Colorado's application to the Colorado Public Utility Commission (PUC) to form a municipal electric utility. Conducted independent technical review of separation of electric assets and appeared as an expert witness before the CPSC on behalf of IBM.
- **Green Mountain Power (GMP).** Prepared independent testimony and appeared as an expert witness in a rate filing before the Vermont Public Service Commission (VPSC). Testimony supported capital investments for generation, transmission, distribution, IT/OT and physical assets.
- **NV Energy (Sierra Pacific Power Company).** Conducted a T&D avoided cost study to support an SPPC's rate filing and to determine Excess Energy Charges for net metering customers. Submitted expert testimony before the Nevada Commission on T&D marginal costs and application to NEM solar.
- **Toronto Hydro Electric System, Limited (THESL).** Prepared business case studies for major capital programs in rate filings before the Ontario Energy Board (OEB). Testified as an independent expert witness before the OEB on Distribution System Plans and renewable energy programs in Custom Incentive Rate (CIR) and Incremental Capital Module (ICM) filings.
- **Exelon (Philadelphia Electric Company).** Developed T&D avoided cost study to support PECO energy efficiency programs. Participated in a statewide stakeholder process to approve T&D avoided costs, which included the statewide EE program evaluator, the electric utility and related parties.
- **Puerto Rico Electric Power Authority (PREPA).** Conducted a T&D avoided cost analysis and prepared expert testimony to support PREPA's rate filing and avoided costs applied to net metering.
- **Public Utility Authority (Israel).** Conducted a technical and economic review of the Israeli Electric Corporation and Palestinian Electric Authority electric generation and power delivery system on behalf of the PUA. Assessed the adequacy of electric infrastructure, power costs and investment programs.
- **Vermont Department of Public Service (VDPS).** Conducted a geo-targeted analysis of energy efficiency programs designed to defer T&D investments. Worked with electric utility stakeholders to identify cost-effective deferral opportunities and to assess processes designed to target EE programs.

Guidehouse
Outwit *Complexity*

Eugene L. Shlatz

Contractor – Contingent Worker

- **Canadian Utility (Confidential) –** Confidential study to assess the value and strategic benefits of the acquisition of electric utility energy delivery assets. Included a technical and economic assessment of key regulatory and acquisition risk factors to support a recommendation.

- **Progress Energy.** Project manager of a best practices and compliance review of fixed asset charging practices. Reviewed methods, systems and practices used to record fixed assets for Florida and the Carolinas to support proposed changes filed with state commissions and the SEC.

- **Citizens Utilities/Vermont Electric Cooperative.** Supported numerous Certificate of Public Good (CPG) applications before the Vermont Public Service Board (VPSB). Expert witness for technical, environmental, and costing studies.

- **Vermont Department of Public Service (VDPS).** Conducted research and prepared sections of the Twenty-Year Electric Plan, including the impact of the independent system operator (ISO) and regional transmission organization (RTO) initiatives on Vermont's transmission providers.

- **Potomac Electric Power Company (PHI).** Project manager of a benchmarking study of storm hardening measures. Assessed the impact of hardening options on reliability and performance. Also assessed service quality (SQI) measures and performance-based rate (PBR) mechanisms.

- **Citizens Utilities (Vermont Electric Division).** Project manager for a T&D Audit mandated by the Vermont Public Service Board. Reviewed T&D plant accounting systems and processes, and provided recommendations for improvement.

- **Massachusetts Department of Telecommunications and Energy (MDTE).** Project manager of a stray voltage assessment of jurisdictional utilities. Identified causes of stray voltage and provided recommendations to mitigate future events, including action and improvement plans

Asset Management

- **Horizon Utilities Corporation.** Developed strategies and provided ongoing support for HU's asset management initiative. Conducted a gap analysis and implementation of asset management strategies and evaluation methods. Included an evaluation of infrastructure upgrades, operational and reliability improvement and implementation strategies using AM-based approaches.

- **First Energy**. Lead consultant of a project team that implemented asset management processes and capital prioritization models for 6 operating companies in three jurisdictions. Responsible for model development and applications, technical review and overall quality assurance.

- **Seattle City Light**. Conducted a benchmarking and gap analysis of the power supply and energy delivery business units. It included a business case analysis to support implementation of asset management methods and new AM organization.

- **Pepco/Conectiv (PHI)**. Responsible for an asset management and prioritization assessment of capital improvement and O&M programs for three states and the District of Columbia. It included developing asset prioritization methods for transmission, distribution and IT programs.

Guidehouse
Outwit *Complexity*

Eugene L. Shlatz

Contractor – Contingent Worker

- **Entergy**. Responsible for an asset management and prioritization assessment of Entergy's capital improvement programs for six jurisdictional utilities in 5 states. It included developing asset-specific prioritization methods for transmission and distribution programs.
- **PacifiCorp**. Responsible for an asset management and prioritization assessment of PacifiCorp's capital improvement programs for six jurisdictional utilities in 6 states. It included developing asset-specific prioritization methods for transmission and distribution and IT programs.

Work History

- Navigant Consulting, Director
- Stone & Webster Management Consultants, Executive Consultant
- Green Mountain Power Corp, Assistant Vice President, Energy Planning
- Ernst & Whinney, Supervisor
- Gilbert/Commonwealth, Senior Consulting Engineer
- Westinghouse Electric Corporation, Systems Analysis Engineer
- Boston Edison Company, Student Engineer, Cooperative Education Prog.

Certifications, Memberships, and Awards

- Professional Engineer - State of Vermont
- Institute of Electrical and Electronic Engineers, Section Chairman (Past)

Education

- M.S. Electric Power Engineering, Rensselaer Polytechnic Institute
- B.S. Electric Power Engineering, Rensselaer Polytechnic Institute

Articles, Publications and Course Instruction

- Grid Reliability and Resiliency Initiatives for the Island of Puerto Rico," Midwest Energy Solutions Conference, Chicago, February 2019.
- "Microgrid Development – Making it Work: ," Instructor: PowerGen Competitive Power College, Orlando, December 2016.
- "DG Proliferation Trends, Challenges and Solutions Addressing Interconnection Planning, Operations, Benefits & Cost Allocation," Instructor: DistribuTECH University, San Diego, Feb. 2015.
- "Smart Grid and Distributed Energy Storage," Total Energy USA, Houston Texas, November 2012.
- "Distributed Generation: Grid Impacts and Interconnection Strategies," Rocky Mountain Electric League, 2012 Spring Management, Engineering and Operations Conference, Omaha Nebraska.
- "Energy Storage Opportunities for Integration of Large-Scale Renewable Generation," Electricity Storage Association (ESA) Annual Conference, Washington DC, May 2012.

Guidehouse
Outwit *Complexity*

Eugene L. Shlatz

Contractor – Contingent Worker

» "Grid Integration of Renewable, Intermittent Resources," 2011 PowerGen International Conference, December 2011, Las Vegas, NV, with Vladimir Chadliev.

» "Reducing T&D Investments Through Energy Efficiency" IEPEC, August 2011, with K. Parlin & W. Poor.

» "Value of Distributed Generation and Smart Grid Applications," DistribuTECH, San Diego, Feb. 2011.

» "Prioritization Methods for Smart Grid Investments," EEI Perspectives, April-May, 2010.

» "Evaluation of Targeted Demand-Side Management at ConEd (CECONY)," ACEEE Energy Efficiency Conference, September, 2009, with Craig McDonald.

» "DER Operational & Grid Benefits" Electric Light & Power, February, 2009.

» "Benefits of Smart Grid Integration with Distributed Energy Storage Systems," Infocast Power Storage Conference, July, 2008.

» "The Rise of Distributed Energy Resources," Public Utilities Fortnightly, Feb, 2007, with S. Tobias.

» "Risk Planning & Project Prioritization: Bringing Energy Delivery to the Next Level in Asset Management," InfoCast T&D Asset Management Conference, St. Louis, MI, May 2004.

» "Valuation Methods: Estimating the Value of Avoiding the Risks Associated with T&D Reliability Failures," EEI Spring 2004 T&D Conference, Charlotte, NC, April 2004.

» "Reliability Tradeoffs," EEI Perspectives, January-February, 2004, with Daniel O'Neill.

» "What's the Outlook for Distributed Generation Interconnection Standards?" 2003 PowerGen International Conference, Las Vegas, Nevada, December 2003.

» "Federal Interconnection Standards: Putting DG in a Box," Public Utilities Fortnightly, April 2003, with Stan Blazewicz.

» "An Innovative Approach to Fact-Based Distribution Reliability Cost Optimization," Distribution 2000, Brisbane, Australia, November 1999, with Cheryl Warren.

» "System Reliability: Competitive Issues," Rethinking Electric Reliability Conf., Chicago Il, Sept 1997.

» "Reliability: Competition & Keeping the Lights On," EUCI, Denver, Colorado, October 1998.

» "System Reliability in a Restructured Environment," Electric System Reliability in a Competitive Environment Workshop, Denver, Colorado, October 1997.

» "Privatization Efforts in South America" EUCI Workshop, Denver, Colorado, January 1997.

» "Open Access Pricing Issues," Transmission Pricing Conference, Vail, Colorado, Sept. 1996.

Guidehouse
Outwit Complexity

Eugene L. Shlatz

Contractor – Contingent Worker

Testimony and Appearances as an Expert Witness

Case Description	Company	Year	Docket	Jurisdiction
Rate Cases, Resource Planning, Open Access and Regulatory Investigations				
Wholesale Rate Filing (OATT)	Duke Energy	2020	ER20-919-000	FERC
Wholesale Rate Filing (OATT)	NorthWestern	2019	ER-1756-000	FERC
Retail Rate Filing (Net Metering)	NorthWestern	2018	D2018.2.12	Montana
Request for Increase in Retail Rates	GMP	2017	17-3112	Vermont
Transfer of Electric Assets (Municipalization)	IBM	2017	15A-0589E	Colorado
Marginal Cost Study (NEM & Rate Filing)	NV Energy	2016	16-06006	Nevada
Custom Incentive Rate Filing	Toronto Hydro	2016	EB -2014-0116	Ontario
Incremental Capital Module (Rate Filing)	Toronto Hydro	2014	EB-2012-0064	Ontario
Summer/Winter 2011 Storm Review	Exelon/ComEd	2013	11-0588	Illinois
Distributed Generation Integration	NV Energy	2012	10-04008	Nevada
Distributed Utility Planning	CUC	2011	6290	Vermont
Power Purchase Contracts – IURC Complaint	Jay REMC	2003	9704-CP-069	Indiana
Section 205 Filing – Wholesale Rates	NISource	1998	ER96-35-000	FERC
Open Access Transmission Tariff Filing	NISource	1997	ER96-399-000	FERC
Request for Increase in Wholesale Rates	NISource	1996	ER92-330-000	FERC
Request for Increase in Retail Rates	GMP	1996	5532	Vermont
Least-Cost Planning Integrated Resource Plan	GMP	1991	5270	Vermont
Request for Increase in Retail Rates	GMP	1991	5428	Vermont
Request for Increase in Retail Rates	GMP	1990	5370	Vermont
Request for Increase in Retail Rates	GMP	1989	5282	Vermont
Request for Increase in Retail Rates	GMP	1988	5125	Vermont
Certificates of Public Good				
Transmission Line Construction Authorization	SSVEC	2010	E-01575A	Arizona
Northern Loop Transmission Upgrades	Velco/CUC	2004	6792	Vermont
Substation Reconstruction – Richford	CUC	2003	6682	Vermont
Island Pond to Bloomfield Line	CUC	2001	6044	Vermont
HK Webster Substation	CUC	1999	6045	Vermont
Burton Hill Substation	CUC	1999	6046	Vermont
Border to Richford 120/46kV Line	CUC	1998	5331A	Vermont
New Transmission Lines and Substation	IBM	1991	5549	Vermont
New Substation – Northern Vermont	GMP	1990	5459	Vermont
Gas Turbine Interconnection Facilities	IBM	1989	5347	Vermont
Dover Substation Expansion	GMP	1987	5226	Vermont
Industry Restructuring & Asset Transactions				
Purchase of Electric Assets	VEC	2004	6853	Vermont
Certificate of Consent, Sale of Distribution Assets	CUC	2004	6850	Vermont
Certificate of Consent, Sale of Transmission Assets	Velco/CUC	2004	6825	Vermont
Prudency Review and Audit Support	CUC	2003	5841/5859	Vermont
Competitive Opportunities Filing	ConEdison	1997	96-E-0897	New York

Guidehouse

KENTUCKY POWER
An AEP Company

Independent Review of Reliability Performance

&

Distribution System Investments

November 6, 2023

Independent Review & Assessment

Distribution Reliability Performance and Investments

Table of Contents

List of Figures

List of Tables

Executive Summary

Guidehouse was engaged by Kentucky Power Company (Kentucky Power) to perform a detailed review of Kentucky Power's reliability performance and investments in its distribution system in response to issues raised in its current rate filing.[1] From its detailed review and analysis of data covering the period 2008 to the present, industry benchmark data for utilities with comparable service territories and distribution systems, and interviews with Kentucky Power, Guidehouse offers the following findings and conclusions.

Kentucky Power's,

- Distribution system is located in a region with among the highest tree coverage and density for the peer group of electric utilities, with low customer density and high average circuit length, each of which are contributing factors to reliability performance;
- Reliability performance as measured by System Average Interruption Frequency Index (SAIFI) is within the peer group average. Reliability performance as measured by System Average Interruption Duration Index (SAIDI) is slightly above the peer group average;
- Tree-related customer interruptions from outside the right-of-way (TOR) is the leading cause of outages. Kentucky Power proposes to reduce TOR interruptions via incremental investments under its proposed Distribution Reliability Rider (DRR);
- Spending on capital projects and maintenance is at or above the peer group average, which is notable for a utility that has experienced a decrease in customers and demand;
- Vegetation management practices are at or above industry practices, with trimming completed on schedule and clearances based on species type and location;
- Equipment failures are the second leading cause of customer interruptions. Proactive efforts to reduce customer interruptions via replacement of equipment with high failure rates (such as cutouts and insulators) are underway. Kentucky Power proposes to expand its ongoing replacement program through incremental investments under the proposed DRR;
- Capital spending on distribution assets as measured by total distribution investments and number of customers is at or above industry averages, which is notable as Kentucky Power has experienced a decline in load growth and number of customers served;
- Spending on distribution maintenance as measured by distribution line miles and number of customers is at or above industry averages;
- Equipment maintenance practices, procedures and inspection intervals is consistent with industry practices, with inspection cycles completed on time;
- Emergency restoration procedures, which include a centralized Incident Command structure, are consistent with industry practices; and
- Storm restoration intervals as measured by customers restored over storm duration, and restoration costs are within industry averages for most types of storms (e.g., wind and snow), except ice storms where costs are higher due to tree density and storm severity.

[1] Case No. 2023-00159.

1. Introduction

1.1 Background

Kentucky Power engaged Guidehouse (consulting) to perform a detailed review of Kentucky Power's reliability performance and investments in its distribution system in response to issues raised in its current rate filing.[2] Guidehouse's review sought to determine if Kentucky Power's distribution operations, maintenance, and storm restoration processes and investments are consistent with practices of electric utilities with comparable service territories and distribution systems. In addition, Kentucky Power requested Guidehouse to perform a review of their planning and capital investment process to determine if they are appropriate and consistent with good utility practice.

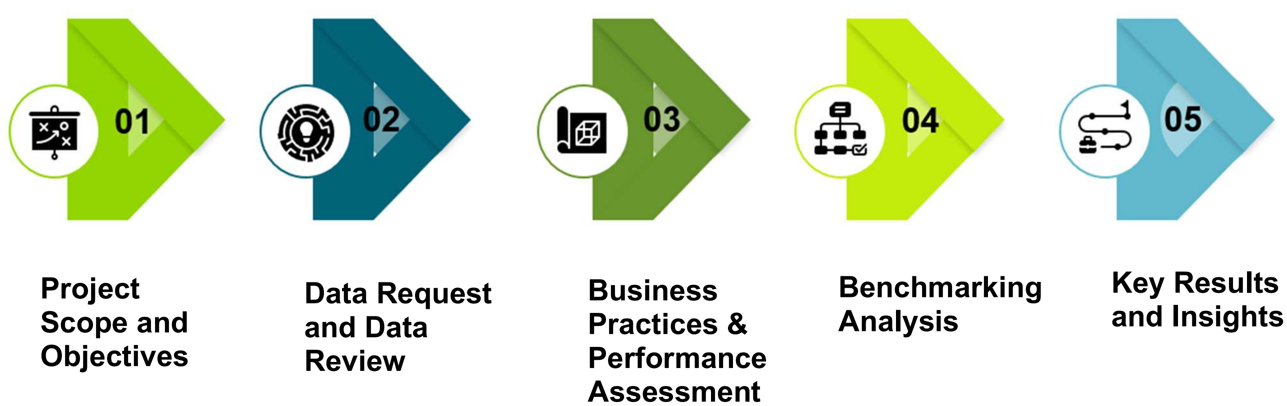
Guidehouse's review and assessment of Kentucky Power included on-site field visits, a series of interviews with Kentucky Power personnel, a comprehensive review and assessment of performance and costs, and an in-depth comparison review of utility practices spanning a range of reliability performance, investment levels and operations. A key element of Guidehouse's review included benchmarking Kentucky Power's reliability performance to other distribution utilities with comparable territory attributes.

This report highlights the key findings of the analysis and provides insights from Guidehouse's subject matter experts who have reviewed, in depth, information provided by Kentucky Power.

1.2 Guidehouse Scope of Work and Approach

The analysis was focused on Kentucky Power's distribution system. Transmission practices are outside of the scope of work. Guidehouse used a 5-step approach to assess Kentucky Power's system reliability, operating/maintenance practices and investments as shown in Figure 1.

Figure 1. Guidehouse Approach



Guidehouse's review and assessment included an analysis of Kentucky Power's planning and design, investment levels and reliability performance outlined in Table 1. Guidehouse requested

[2] Case No. 2023-00159

data from Kentucky Power in each these areas for up to 15 years and benchmarked key metrics to those of other electric utilities with comparable service territories.

Table 1. Topics Addressed and Analyzed

Topics Assessed	Description
Benchmarking	Reliability metrics (SAIDI, SAIFI, CMI[3]), spending (capital & O&M)
Economic Growth	Historical and forecasted load and customer growth / contraction
Vegetation Management	Distribution vegetation standard, planned and completed work
Distribution Capacity Plans	Substation and feeder: line capacity, peak load, forecast, historical investments
Maintenance	Substation and distribution maintenance planned and completed
Engineering Standards	Distribution planning and design, and loading practices
Reliability Programs	Description and investment level of each reliability program
Grid Modernization	Description of program, planned and actual spending per year
Emergency Response	Incident Command Structure, mutual aid, pre-planning
Storm Restoration	Customer restoration times and costs

[3] Customer Minutes of Interruption.

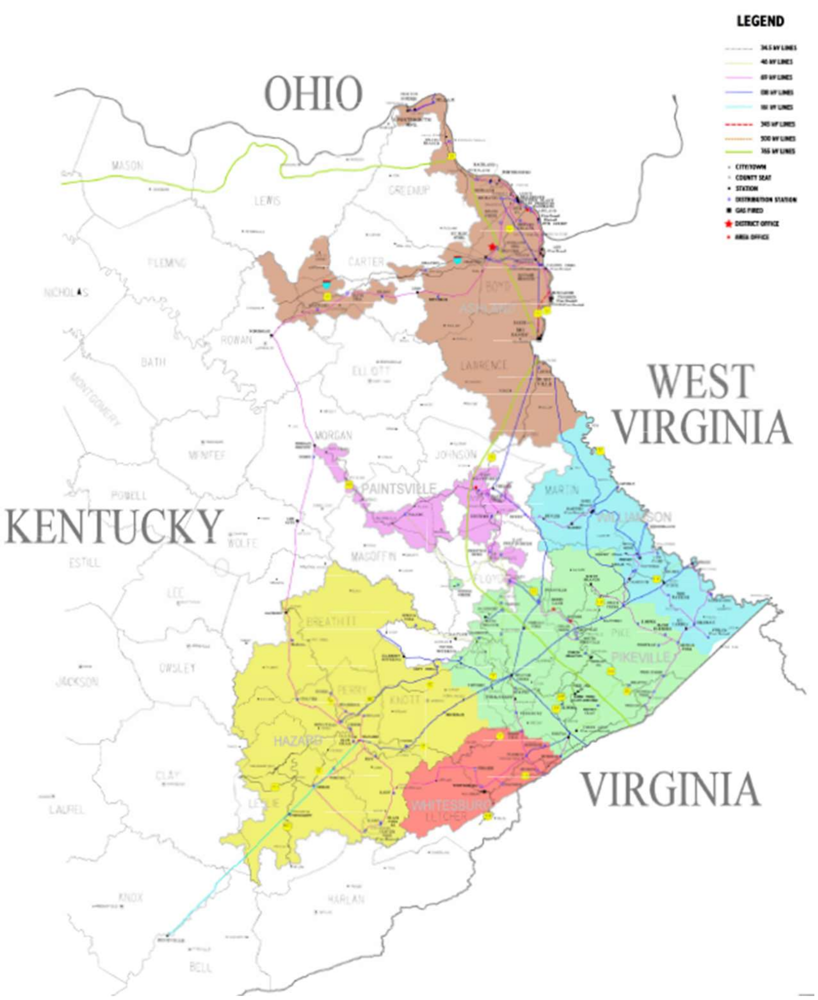
2. Key Findings and Insights

2.1 Overview

The following sections document Guidehouse's key findings and insights on Kentucky Power's reliability, spending, planning, engineering design standards and maintenance practices. It includes benchmarking Kentucky Power's current and past practices with utilities with comparable distribution system attributes and topography. Guidehouse's benchmarking analysis focused on the past five to ten years, as data typically was available during these years.

Figure 2 presents Kentucky Power's service territory boundaries and operating areas. A significant portion of Kentucky Power's service territory is located in heavily forested rural areas of Kentucky, which constitutes an important aspect of our review, as it includes benchmarking Kentucky Power's reliability performance, spending levels and maintenance practices with those of other utilities with similar distribution systems.

Figure 2. Kentucky Power Service Territory[4]



[4] Six districts are highlighted that correspond to areas tracked in Kentucky Power's Outage Management System.

2.2 Industry Benchmarking

To evaluate Kentucky Power's reliability and spending using comparable benchmarks, Guidehouse selected a peer group of electric utilities with similar distribution system attributes, including number of customers, topography, and percent vegetation.

Peer Group Selection

Guidehouse applied a five-step elimination process to select a peer utility group for benchmarking Kentucky Power's reliability performance and costs with those of utilities with comparable service territories. Because of the high percentage of interruptions caused by trees, Guidehouse selected utilities located in states with rural load and extensive tree coverage for peer group benchmarking. Sixty-one utilities were identified as candidates for benchmarking; each are listed in the Appendix. Of these 61 utilities, twenty-one, including Kentucky Power, were chosen for the peer utility group. The steps that Guidehouse followed to select the peer group are outlined below.

- **Criteria 1**: Collect data for all utilities in four states with the highest percentage of forested areas and that are comparable to Kentucky, and that report reliability indices)[5]
- **Criteria 2**: Remove 19 municipal utilities as they typically have smaller service areas and shorter distribution lines
- **Criteria 3**: Remove four other utilities that serve large urban areas
- **Criteria 4**: Remove 15 utilities with tree coverage below 85%
- **Criteria 5**: Remove two utilities that serve less than 10,000 customers

As noted above, the selection process produced a peer group of 21 electric utilities. A key feature of the peer group selection process was the determination of distribution circuit tree coverage. Unlike statewide tree coverage that is based on percent forested, tree coverage in Criteria 4 is based on data collected for the specific service territories of each of the peer group utilities.[6] Guidehouse obtained the data from publicly available sources and the consulting firm First Quartile.[7] Notably, Kentucky Power is among the highest in the peer group, with 99 percent tree coverage.

Table 2 presents the final peer group, of which 9 are investor-owned Utilities (IOUs) and 12 rural electric cooperatives (RECs); the latter of which serve customers located in rural areas with

[5] Includes Maine (ME), New Hampshire (NH), West Virginia (WV), Vermont (VT).

[6] The tree coverage for Kentucky Power and the peer group is high as the analysis assumes that any trees located within a defined "cell block" constitutes 100 percent coverage.

[7] The analysis is based on original research conducted by the U.S. Department of Agriculture. Results are derived via an imaging analysis of 240 by 240 meter "grid cells" including those located within the peer group service territories. Each cell with one of more trees within the cell is assigned as a block with tree coverage. Source: Krist, Frank J., Jr.; Ellenwood, James R.; Woods, Meghan E.; McMahan, Andrew J.; Cowardin, John P.; Ryerson, Daniel E.; Sapio, Frank J.; Zweifler, Mark O. 2014. 2013-2027 National Insect and Disease Forest Risk Assessment. FHTET-14-01. Fort Collins, Colorado: U.S. Department of Agriculture, Forest Service, Forest Health Technology Enterprise Team.

substantial tree coverage. The 21 peer group utilities are benchmarked for reliability as measured by the IEEE P1366 guidelines and for costs. Only the IOUs within the peer group are benchmarked for cost using FERC Form 1 data, as the RECs typically do not report costs via publicly available sources. Further, benchmark data and sources for maintenance practices, storm restoration intervals and storm restoration costs in subsequent sections were obtained from a different set of electric utilities (*i.e.,* outside the peer group) provided by First Quartile Consulting.

Table 2. Industry Benchmarking Peer Group

Utility	Type (IOU or REC)	State	Customer Count[8]	Service Territory Tree Coverage[9]
Kentucky Power	IOU	KY	166,243	99%
Central Maine Power Co	IOU	ME	634,601	95%
Duke Energy Kentucky	IOU	KY	142,504	89%
Green Mountain Power Corp	IOU	VT	264,575	94%
Liberty Utilities (Granite State)	IOU	NH	44,932	98%
Monongahela Power Co	IOU	WV	388,333	98%
Public Service Co of NH	IOU	NH	521,953	88%
The Potomac Edison Company	IOU	WV	204,050	98%
Versant Power (former Emera)	IOU	ME	164,510	96%
Big Sandy Rural Elec Coop Corp	REC	KY	12,778	100%
Cumberland Valley Electric, Inc.	REC	KY	23,831	98%
Eastern Maine Electric Coop	REC	ME	12,708	96%
Grayson Rural Electric Coop Corp	REC	KY	14,813	98%
Jackson Energy Coop Corp (KY)	REC	KY	51,119	96%
Licking Valley Rural Elec Coop	REC	KY	17,327	99%
New Hampshire Elec Coop Inc	REC	NH	81,297	97%
Owen Electric Coop Inc	REC	KY	61,365	91%
South Kentucky Rural Elec Coop	REC	KY	68,891	89%
Taylor County Rural Elec Coop	REC	KY	26,663	85%
Tri-County Elec Member Corp (TN)	REC	KY	26,261	90%
Vermont Electric Cooperative, Inc	REC	VT	38,992	90%

Distribution Spending - Capital

Guidehouse obtained FERC Form 1 data for each of the IOUs to compare total capital spending for distribution versus Kentucky Power for the last 15 years.[10] The RECs are excluded as investment data typically is not publicly available from REC web sites and published reports. Figure 3 and Figure 4 presents Kentucky Power's capital spending for distribution assets versus the IOU peer group. The tables present average 15-year spending by Kentucky Power versus the IOU peer group for both total original plant balances and number of customers served. Two

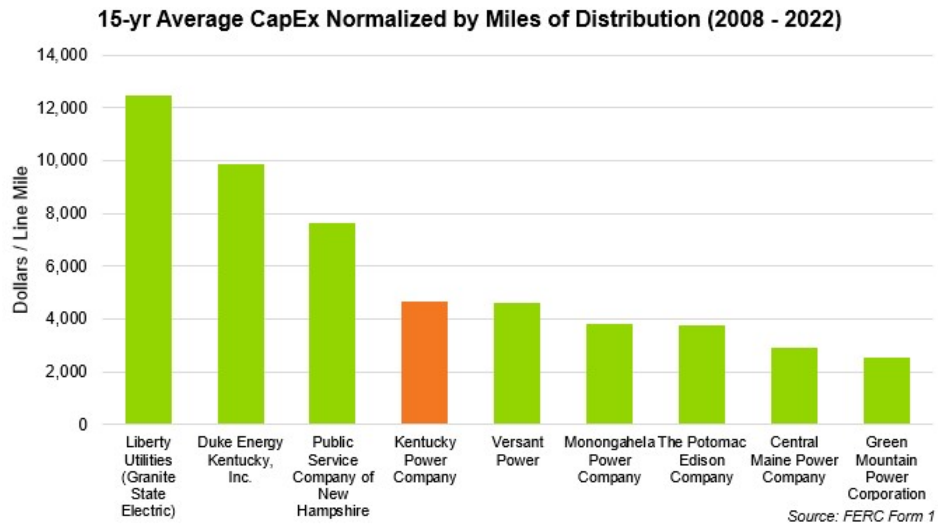
[8] Ten-year average (2013-2022). Calculated using customer data from the U.S. Energy Information Administration. Source: Annual Electric Power Industry Report, Form EIA-861 detailed data files

[9] Percent tree coverage based on utility service territory DATA. Guidehouse obtained the data from the consulting firm First Quartile (see additional information under Criteria 4).

[10] FERC accounts 360 through 374.

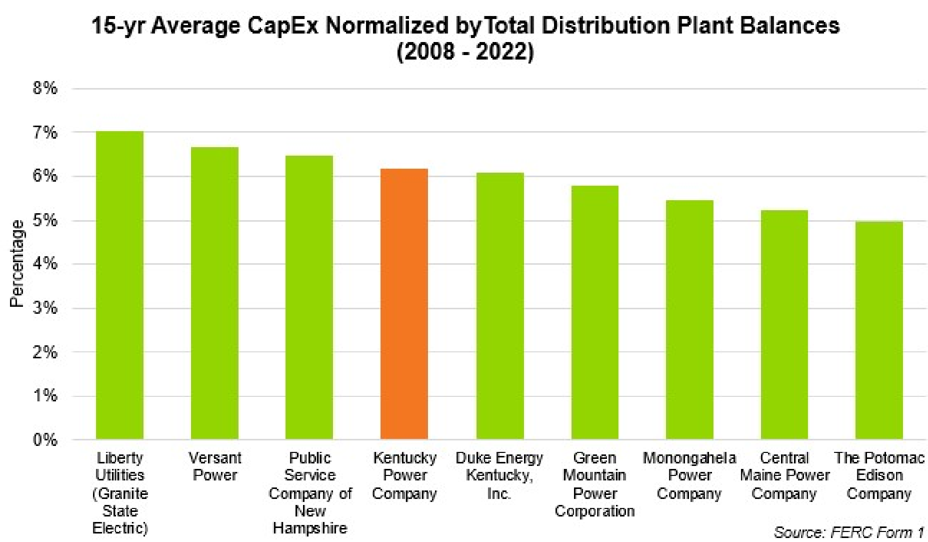
normalizing factors were chosen to compare Kentucky Power's spending on capital to the peer group average for a range of benchmarks.

Figure 3. Kentucky Power Versus IOU Peer Group Capital Spending (by Distribution Circuit Miles)



Results indicate Kentucky Power's capital spending for distribution assets as a function of total original plant balances or distribution line miles is within or above the IOU peer utility group average spending on capital projects.

Figure 4. Kentucky Power Versus IOU Peer Group Capital Spending (by Original Plant Balances)

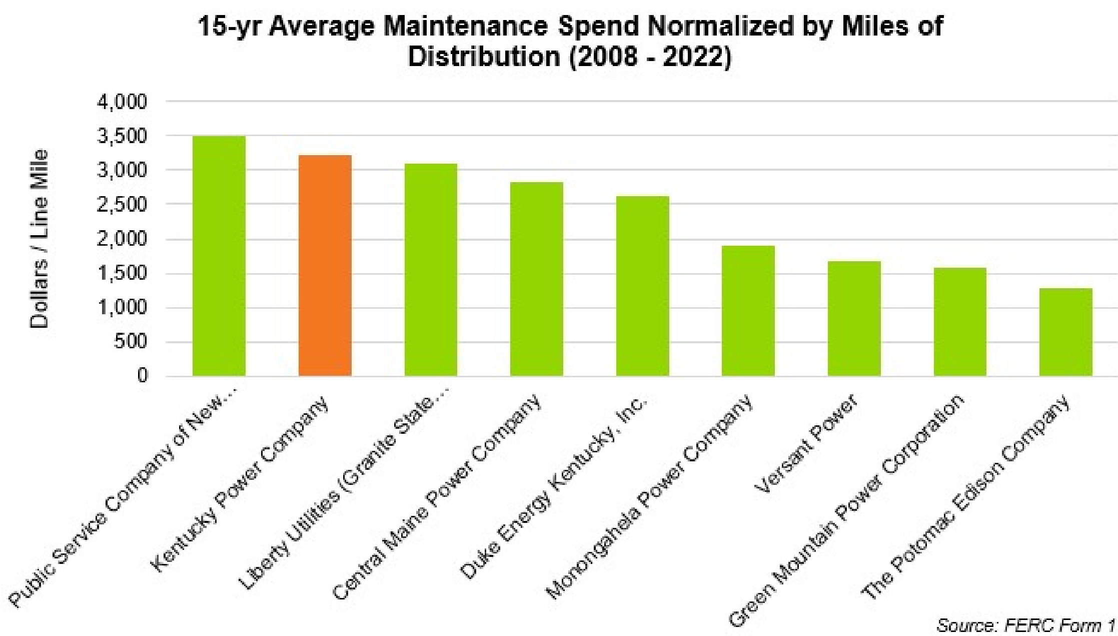


Guidehouse recognizes that benchmark results for the peer utility group likely includes spending for new customer connections and distribution lines needed to accommodate the load growth. Hence, the normalized values for Kentucky Power likely are understated as the number of customers and peak demand in its service territory has declined over the past 10 years.

Distribution Spending – Maintenance

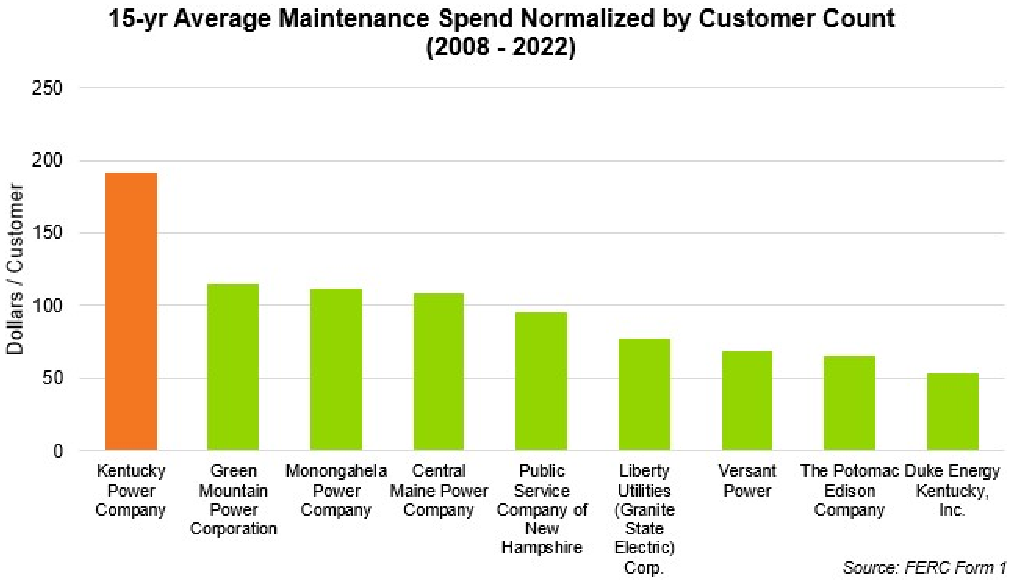
Similar to capital investments, Guidehouse obtained FERC Form 1 data for each of the IOUs to compare total distribution operation and maintenance (O&M) spending versus Kentucky Power for the last 10 years. The RECs are excluded as expense data typically is not publicly available. Figure 5 and Figure 6 present Kentucky Power's maintenance spending for distribution versus the IOU peer group for both the number of customers served and distribution line miles. Two normalizing factors were chosen to compare Kentucky Power's spending for maintenance to the peer group average for a range of benchmarks.

Figure 5. Kentucky Power Versus IOU Peer Group Maintenance Spending (by Distribution Circuit Miles)



Results indicate Kentucky Power's maintenance expenses for distribution assets as a function of total line miles substantially exceeds the peer group average. Guidehouse attributes the higher amount of maintenance expense for Kentucky Power to the high cost assigned to the Overhead Lines account in the FERC Form 1 for distribution. The Overhead Lines account represents a large majority of maintenance expense for Kentucky Power and most of these expenses are for vegetation management, which is higher than the peer group average due to the very high tree density along its distribution circuit rights-of-way (ROW).

Figure 6. Kentucky Power Versus IOU Peer Group Maintenance Spending (Total Customers)



Similar to results obtained for line miles, Kentucky Power's maintenance expenses for distribution as a function of total customers is well above the IOU peer group average.

Reliability and Resilience

Guidehouse also conducted benchmarking of reliability performance of the entire peer group for both Major Event Day (MED) and non-MED statistics.[11] Figure 7indicates Kentucky Power's reliability indices for SAIFI is within peer group averages while Figure 8 indicates SAIDI is above the peer group average without MED. Figure 10 indicate SAIDI with MEDs is closer to the peer group average, most likely due to robust fault isolation and hardening measures undertaken by Kentucky Power. Accordingly, Guidehouse concludes Kentucky Power's reliability performance as measured by the number of customer interruptions is on par with peer group benchmarks, and the higher SAIDI levels are due to longer restore times due to crew travel to locate and repair outages (Table 6 confirms Kentucky Power's distribution circuits are long, particularly 34.5kV lines which average over 50 miles.)

Guidehouse notes that the comparison of Kentucky Power reliability indices to the peer group may not be entirely comparable to the peer group, as Kentucky Power's indices include planned interruptions, whereas many utilities exclude planned interruption from reported reliability indices, consistent with IEEE P1366 recommended practices. **When planned interruptions are excluded, Kentucky Power's reliability indices for both SAIFI and SAIDI are closer to peer group averages**.[12]

[11] Kentucky Power applies IEEE Standard 1366-2017 to derive MED and non-MED reliability indices. MED are derived to identify events caused by storms or other conditions causing a large number of customer interruptions.
[12] Planned interruptions for Kentucky Power are about 15 and 11 percent of non-MED CI and CMI, respectively, over the past five years.

Figure 7. Kentucky Power Versus Peer Group Reliability without MED (SAIFI)

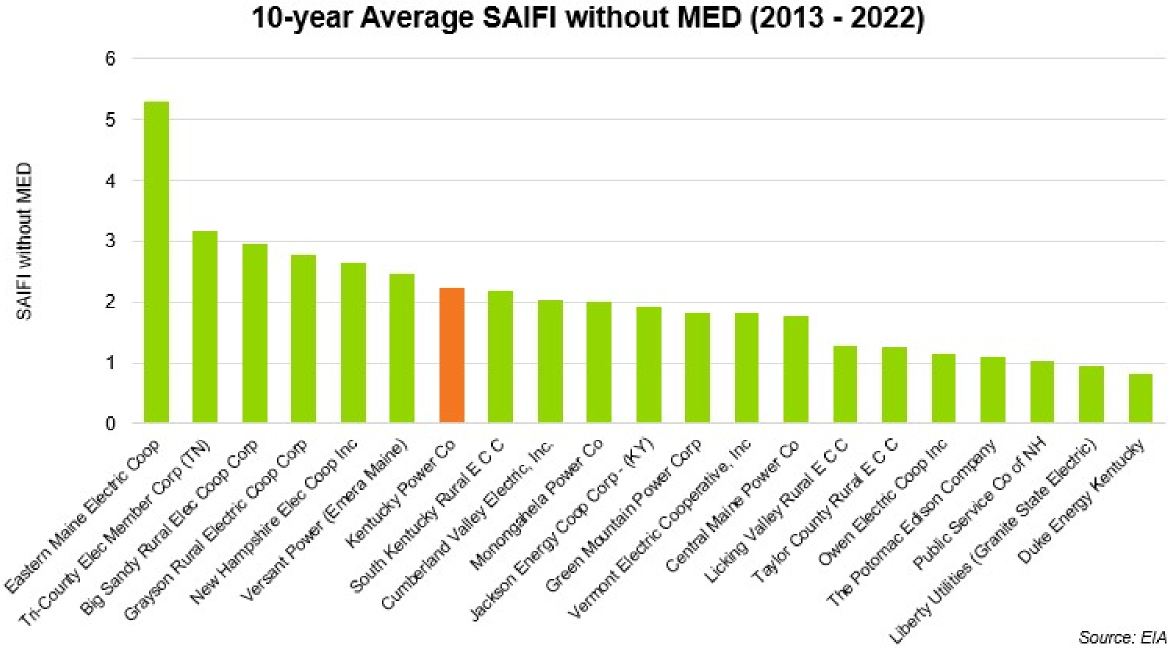


Figure 8. Kentucky Power Versus Peer Group Reliability without MED (SAIDI)

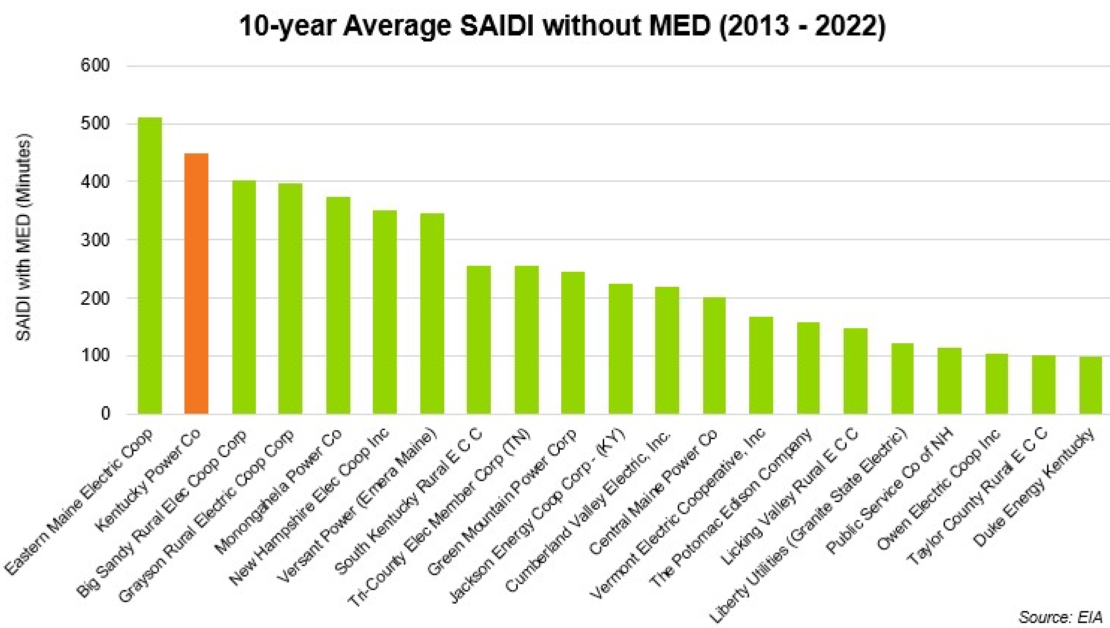


Figure 9. Kentucky Power Versus Peer Group Reliability with MED (SAIFI)

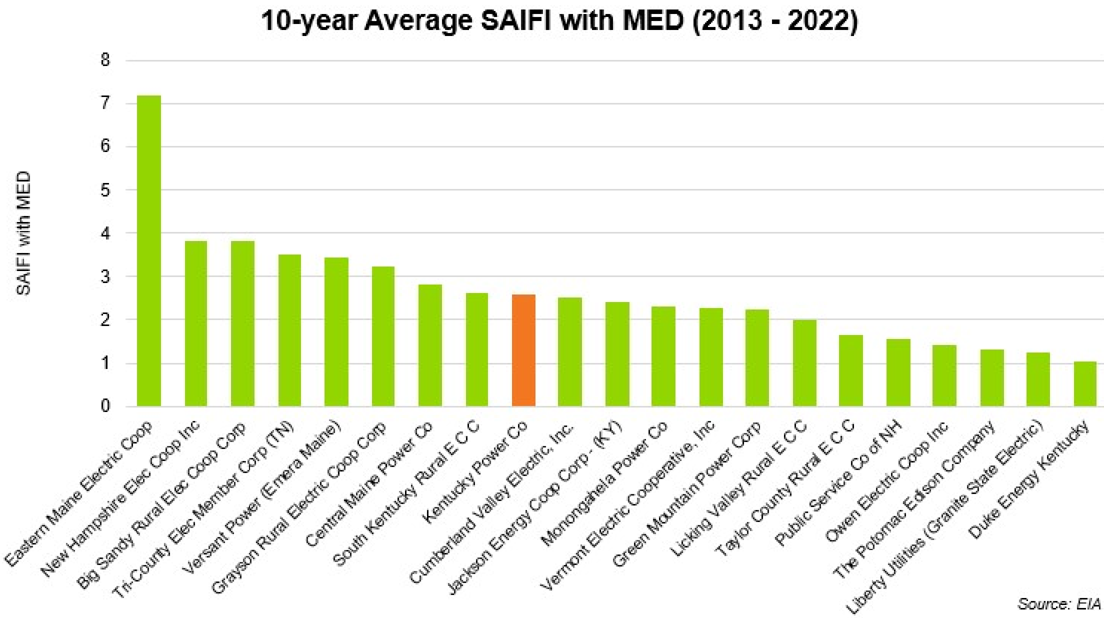


Figure 10. Kentucky Power Versus Peer Group Reliability with MED (SAIDI)

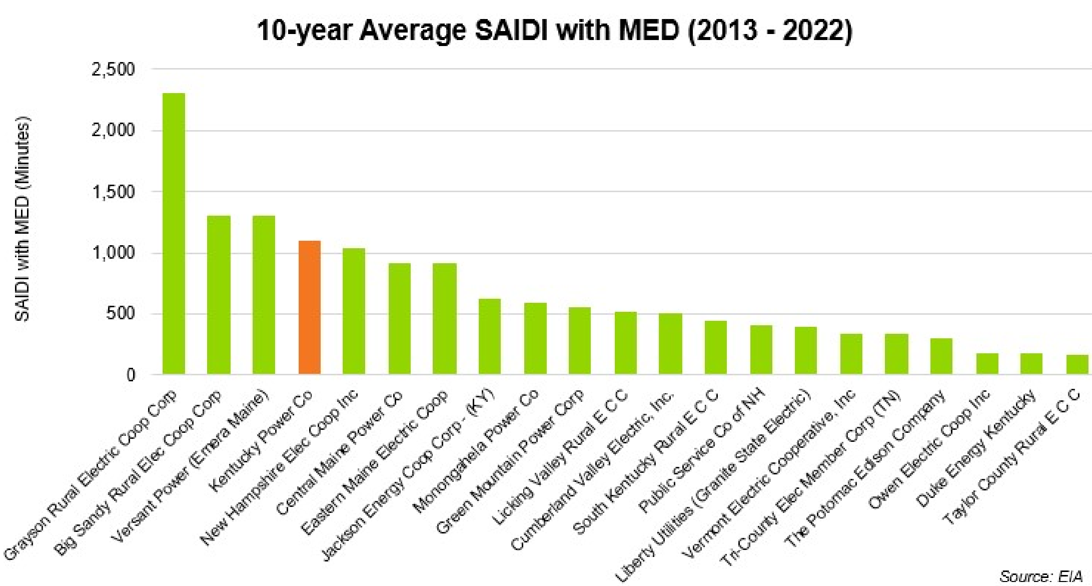
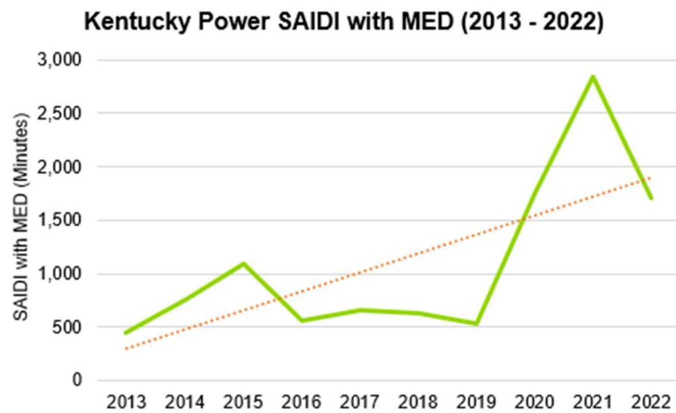


Figure 11 presents Kentucky Power's reliability performance as measured by SAIDI with MEDs annually over the past 10 years. The trendline in the chart indicates that although Kentucky Power's SAIDI during major storm events is closer to the peer group average, indices have trended upward over the past five years. The upward trend confirms that Kentucky Power's proposed spending via the DRR is needed to bring SAIDI to lower levels, particularly for the TOR program which is a primary contributor to SAIDI during major storms.

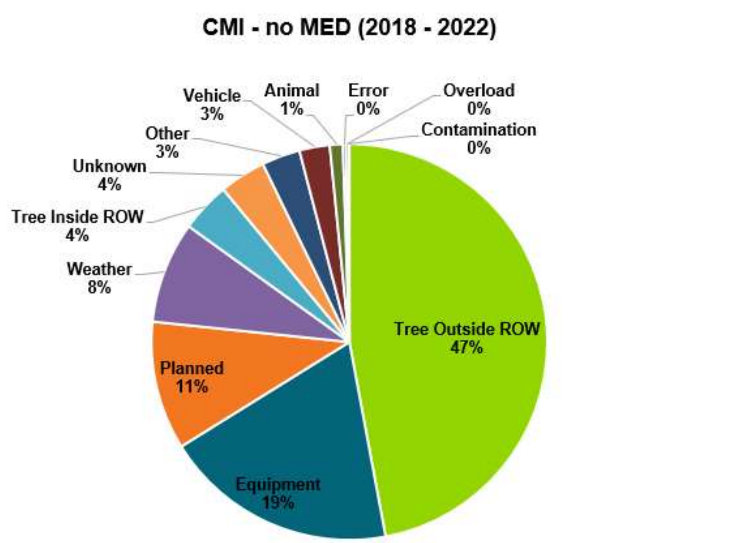
Figure 11. 10-Year SAIDI with MEDs (with Trendline)



Source: EIA

Figure 12 presents Kentucky Power reliability indices over the past five years by cause code. Vegetation Management (VM) in the form of tree contact – Trees in the ROW (TIR) and Trees out of the ROW and weather are the dominant cause codes for both MED and non-MED, distantly followed by equipment failure. The dominance of trees as a cause of outages underscores Kentucky Power's prior and forward-looking focus on mitigating tree relate outages to improve reliability performance. Additional details on VM practices appear in Section 2.3.

Figure 12. Reliability Indices by Cause Code including MEDs[13]



Source: Data provided by KPCO

[13] Guidehouse notes that the derivation of MED events is based on the use of a logarithmic function to differentiate normal versus MED events. Given the number and severity of storms Kentucky Power has encountered during some years {e.g., 2021 and 2022}, the MED threshold likely is higher in these years, which would place a higher number of interruptions into the non-MED category. The outcome of this premise is an increase in non-MED SAIDI and SAIFI during years with high storm activity compared to other utilities that have not experienced the same number or severity of storms.

Table 3 lists the equipment impacted under the equipment cause code (19 percent of all causes) for SAIDI and SAIFI over the past five years. Fused cutouts and insulators are the primary equipment contributing to reliability under the equipment cause code, which underscores Kentucky Power's focus on prioritizing replacing equipment most prone to failure over the past several years and as proposed in its Distribution Reliability Rider (DRR) program.[14] Additional details are presented in Section 2.4.

Table 3. Equipment Cause Code Details

Equipment Description	Sum of CMI (2018 – 2022)	Sum of CMI (MED) (2018 – 2022)	Sum of CMI (non-MED) (2018 – 2022)	Total Number of Failures (2018 – 2022)	Number of Failures (MED) (2018 – 2022)	Number of Failures (non-MED) (2018 – 2022)
Cutout	14,313,832	2,490,630	11,823,202	2743	85	2658
Insulator[15]	13,889,398	93,853	13,795,545	282	5	277
Pole	9,391,038	2,777,772	6,613,266	196	17	179
Other Equipment	8,946,833	4,683,361	4,263,472	196	13	183
OH Conductor	8,349,009	1,517,504	6,831,505	728	37	691
Crossarm	5,876,413	826,861	5,049,552	103	4	99
Transformer (Line)	4,898,864	504,968	4,393,896	930	34	896
Connector / Clamp	4,347,057	304,905	4,042,152	1133	35	1098
Arrester	4,248,768	114,651	4,134,117	244	3	241
Recloser	2,107,196	631,432	1,475,764	38	3	35
Regulator	2,054,652	987,636	1,067,016	26	4	22
Jumper / Riser	1,964,752	61,554	1,903,198	111	3	108
Splice	1,637,811	122,704	1,515,107	250	11	239
OH Switch	1,271,088	0	1,271,088	33	0	33
Fuse	990,270	430,310	559,960	743	16	727
UG Conductor	692,700	88,178	604,522	171	4	167
Relay	644,255	0	644,255	2	0	2

Values presented in Table 3 confirm that Kentucky Power is proposing to allocate spending in the DRR (under Asset Renewal / Storm Hardening) on equipment most susceptible to failure and to equipment that contributes to customer interruption minutes under the equipment cause code – cutouts and insulators are the highest causes of interruptions per customer minute. [16] Guidehouse expects the proposed increase in spending, prioritized for key equipment categories, proposed in the DRR will improve reliability performance along with other measures outlined in the DRR.

> ***Summary Assessment:*** *Kentucky Power's reliability performance and spending is comparable to electric utilities with similar distribution system circuits and locational attributes. Kentucky Power's reliability performance is within the peer group for SAIFI and above the peer group for SAIDI based on metrics reported over the past 5 years. When Kentucky Power's reliability indices are adjusted to exclude planned interruptions, the indices are within or closer to the peer group values. Guidehouse attributes Kentucky*

[14] Kentucky Power describes the proposed DRR as a Work Plan that targets on a programmatic basis, incremental investments for reliability improvements to supplement work completed under base rates. If approved, it will enable Kentucky Power to complete incremental work on a faster timeline and proactively address major outages

[15] Insulators that are not part of the cutout assembly (e.g., post insulators)

[16] Kentucky Power reports that it will monitor and track defective equipment in its the Asset Renewal/Storm Hardening or Resiliency program component of the DRR.

Power's higher SAIDI to the longer average distribution feeder length, particularly on those rated 34.5kV, which require longer crew times to patrol, locate and repair affected line segments. Further, circuits rated 34.5kV are more susceptible to interruptions, which further contributes to Kentucky Power's higher reliability indices.

The greatest percentage of Kentucky Power's interruptions are caused by tree contact, both from within and outside of ROWs, followed by equipment failures, and spending for each cause code has appropriately focused on mitigating interruptions within these causes. Kentucky Power's capital spend on distribution is also consistent with industry benchmarks, which is notable for a utility that has experienced a reduction in the number of customers and electric demand over the past 10 years.

2.3 Vegetation Management

Reliability indices presented in the prior section confirm that trees, both within and outside the ROW, is the dominant cause of interruptions for both MED and non-MED events. Guidehouse's review and assessment of Kentucky Power's VM program addresses the following topics and questions.

- Are Kentucky Power's VM guidelines and clearing practices consistent with good utility practice and in alignment with the benchmark group?
- Has Kentucky Power completed VM maintenance activities consistently on cycle?
- What percent of the interruptions are caused by TIR and TOR? Has the percentage of outages due to trees outside of ROW increased over the past 5 years?
- Are there interim VM activities for hot spots? How does Kentucky Power address problematic circuits via off-cycle trimming?
- How does Kentucky Power VM reliability performance compare to the peer group benchmark; that is, utilities with service territories in rural, high density treed areas?

Forestry Management Standards and Benchmark Performance

Kentucky Power's VM standard is outlined in AEP's *Forestry Management Guidelines*.[17] The guidelines apply to transmission lines and primary and secondary distribution lines.[18] The guidelines include a comprehensive set of clearance requirements and practices for forestry activities covering contractor performance, clearing practices for different species and tree location, danger and hazard trees, customer and public notifications, and data collection. Section 6 addresses specific requirements for distribution primary and secondary clearing. Guidehouse's review of the guidelines confirms that Kentucky Power's VM activities, as outlined in the document, are consistent with good utility practice.

[17] AEP Forestry: Vegetation Management Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance Operations.
[18] The VM Guidelines exclude tree trimming or removal for the customer service drop, which are the responsibility of the customer.

Kentucky Power conducts tree clearing on its distribution system on a 5-year cycle. Figure 13 presents trim cycles for rural segments of distribution systems for the benchmark group of utilities .[19] Results confirm that Kentucky Power's trimming cycle is within industry averages.

Figure 13. Trim Cycle for Rural Line Segments (IOUs)

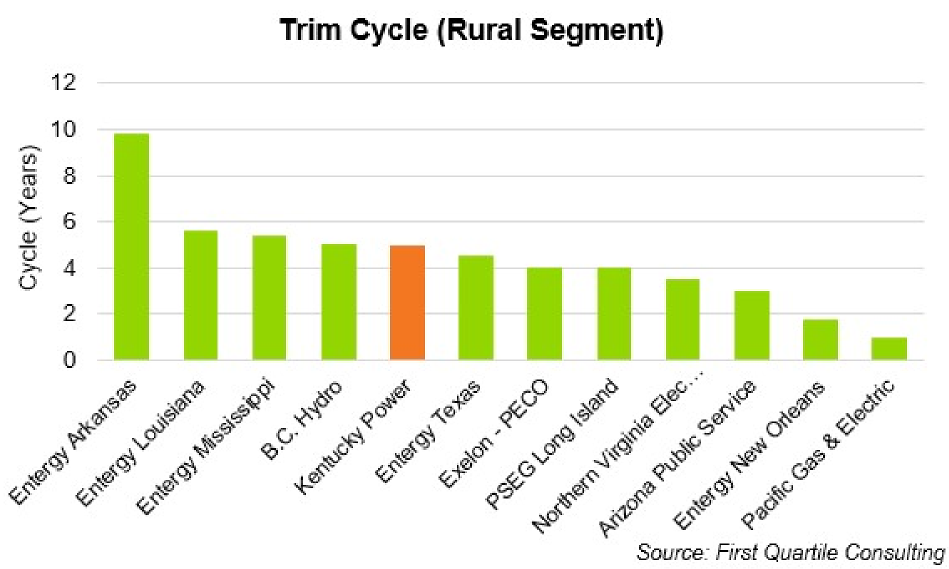


Figure 14 confirms that Kentucky Power's VM program achieved its trimming schedule over the past five years, with minimal variance between targeted and completed miles.

Figure 14. Kentucky Power 5-Year Tree Clearing Cycle

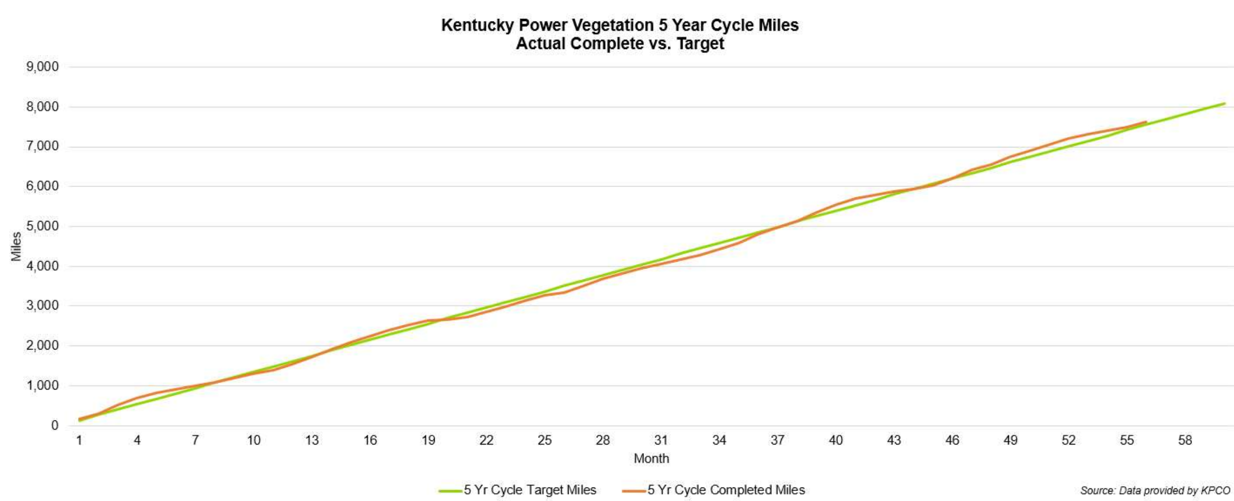
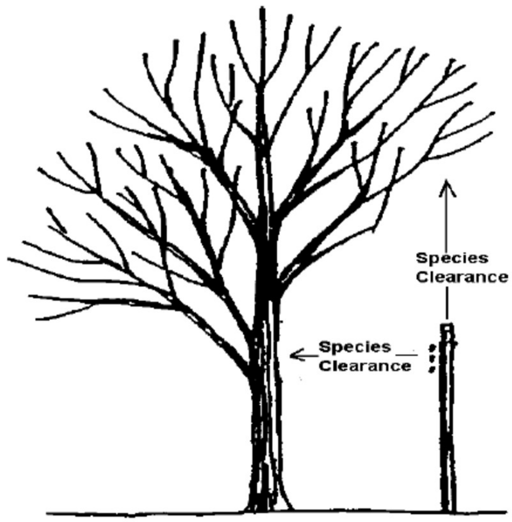


Figure 15 presents Kentucky Power's tree clearance guidelines for species located within the ROW. It highlights the clearance envelope for overhang and side clearances from primary

[19] Benchmark group provided by 1st Quartile Consulting. Values exclude the urban segment of each utility, where applicable.

conductors required for Kentucky Power's 5-year trimming cycle. These clearances meet or exceed industry practices based on Guidehouse's VM experience at other electric utilities.

Figure 15. Kentucky Power Distribution Clearance Guidelines[20]



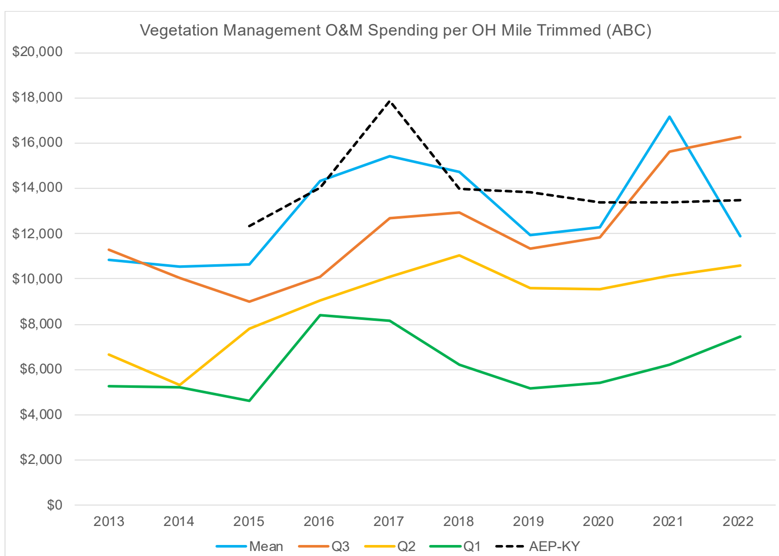
Minimum Clearances by Species:

- Fast Growing – 20 ft
- Medium Growing – 15 ft
- Slow Growing – 10 ft

Reliability Performance and Industry Benchmarks

Figure 16 presents Kentucky Power's spending on vegetation management per mile of line versus industry benchmarks over the last 10 years. Results indicate the percentage of tree-related interruptions for Kentucky Power is above the industry benchmark. The much higher level of interruptions as measured by CMI further supports Kentucky Power's TOR component of its proposed DRR described in the following subsection.

Figure 16. Kentucky Power VM Reliability Performance Versus Industry Benchmark Group



Source: First Quartile Consulting and KPCO

[20] FOD_025_Forestry_Clearing_and_Operating_Guidelines_Rev_6_03AUG22, pp. 14 – 17.

Targeted VM Practices and TOR Program

In addition to scheduled 5-year trimming, Kentucky Power conducts off-cycle trimming to address hot spots or danger trees identified during line inspections, particularly when danger trees that could cause interruptions are detected. It includes customer notification and approval for tree removal for those located outside of the ROW. Each of these practices are consistent with or exceed practices at other electric utilities.[21]

Outage records reveal that a sizable percentage of interruptions under the tree cause codes is caused by trees outside of the ROW falling onto distribution lines and equipment. Accordingly, in 2018 Kentucky Power instituted a pilot program to widen existing ROWs to proactively address TOR outages, including the targeting of circuits with high exposure to danger trees. Table 4 presents Kentucky Power's annual capital spending on forestry, which increased in 2018 for the TOR pilot program. Kentucky Power reports the pilot produced a 15 percent reduction in SAIDI on circuits selected for ROW widening.

Table 4. Capital Investments - Forestry

Year	Capital Spend
2016	$3,718,526
2017	$3,789,067
2018	$8,925,445
2019	$14,401,892
2020	$8,439,419
2021	$12,753,906
2022	$9,444,069

Kentucky Power proposes to further enhance its VM Program to include targeted ROW widening (*TOR – Enhanced ROW Widening Program*) as one of the key components of its proposed incremental DRR, focusing on circuits that have experienced subpar reliability or on those most susceptible to TOR outages. The TOR program will supplement Kentucky Power's 5-year inspection cycles and enhance off-cycle trimming as a separate program. Guidehouse expects reliability gains realized via the TOR pilot program will be achieved on other circuits, subject to Commission approval of the TOR component of the DRR.

> ***Summary Assessment:*** *Kentucky Power's vegetation management program is consistent with or exceeds practices applied by electric utilities with comparable distribution system attributes and tree coverage. Kentucky Power's spending on VM aligns with industry benchmarks and it has met targeted trimming cycles. Clearance guidelines recognize differences in tree species with clearance envelopes that often exceed those established for other North American utilities. Kentucky Power's TOR pilot and proposed spending for TOR in its DRR is consistent with or exceeds industry practices, with its TOR pilot confirming measurable reliability benefits achieved by the TOR program. Trees located outside of the ROW is a leading cause of interruptions. Hence, Guidehouse expects that Kentucky Power's reliability will improve and SAIDI*

[21] Guidehouse's experience with VM at other utilities indicates Kentucky Power's TOR activities are more comprehensive than those of other utilities.

levels will more closely align with the benchmark peer group upon full implementation of the proposed TOR – Enhanced ROW Widening program.

2.4 Capacity Planning and Engineering Standards

Guidehouse's independent assessment of Kentucky Power's capacity planning and engineering standards addresses the following topics and questions.

- Are Kentucky Power's planning, design and maintenance practices based on standards that are consistent w/ good utility practice?
- Are the levels of Kentucky Power's capacity investments appropriate given historical growth in electricity demand for distribution substations and feeders?
- Are investment decisions made to balance capacity and reliability objectives?
- What criteria is applied to determine when and where reliability investments are needed, and what drives investment decisions?
- What are Kentucky Power's equipment maintenance policies and are these consistent with industry good practices?
- Where differences exist with the benchmark peer group, are there factors that need to be considered to explain and justify these differences?

To support its assessment, Guidehouse conducting an extensive review of Kentucky Power's planning and design processes, line and equipment loading criteria, and records to support our findings. Guidehouse interviewed Kentucky Power personnel responsible for planning and standards to confirm our understanding and review of Kentucky Power's practices and how decisions are made to determine the investments needed for distribution line capacity and reliability requirements. Guidehouse also reviewed prior Kentucky Commission Orders and reports, and Kentucky Power's 2023 rate filing, to supplement our independent review. Lastly, Guidehouse evaluated, via benchmarking analyses, Kentucky Power's standards and investments to those of other electric utilities with comparable distribution system properties and service territory attributes.

Distribution Line Capacity Planning

Kentucky Power's distribution line capacity planning and design criteria are documented in AEP's *Distribution System Planning Criteria* manual.[22] It describes each step in the process that planners follow to "financial requirements, the justification for implementing the proposed improvement plans to management, and the risk of not doing the project." The manual documents equipment loading and performance criteria, and guidelines each operating company should follow to determine the timing and type of upgrades or mitigation options needed to address loading and performance violations.

The manual also addresses reliability criteria, including how decisions on distribution line capacity investments should factor in reliability benefits. The document thoroughly describes the processes Kentucky Power follows to determine when line capacity upgrades are needed, equipment normal and emergency loading limits, and methods planners should apply to assess

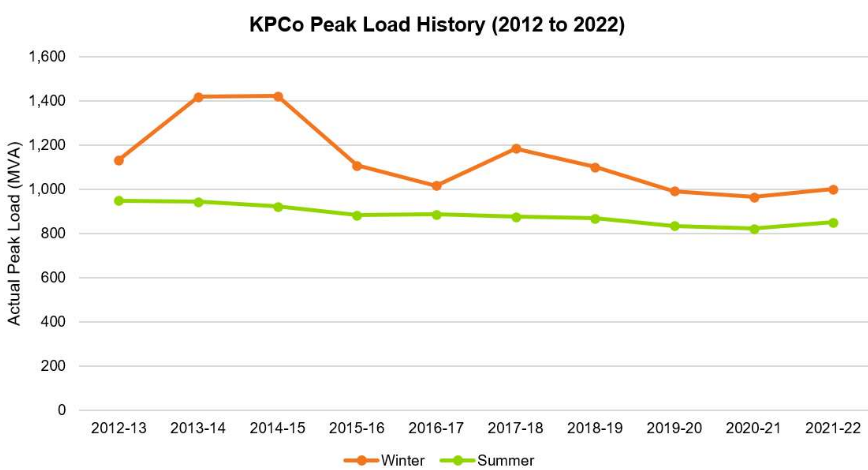
[22] American Electric Power, *Distribution System Planning Criteria*, October 2016 Revision. Prior revision dated May 2007.

candidate upgrades. The manual outlines options to address state loading or voltage violations on a least cost basis such as distribution line capacity expansion (e.g., new or higher rated substation transformers or new feeders), phase balancing, enhancing tie transfer capability; and approaches to mitigate dynamic performance violations such as harmonics and voltage flicker. Guidehouse interviewed Kentucky Power's distribution planning management team and confirmed the guidelines outlined in the manual are followed and described investments made over the past 12 years to comply with documented processes and planning criteria.

Kentucky Power's distribution planners use AEP's Distribution – Planning (DGP) model to determine the timing and magnitude of distribution capacity violations over a 10-year summer and winter demand forecast. The model lists every distribution substation, substation transformer, and feeder, along with equipment rating and capacity loading limits based on AEP planning and equipment loading standards. These standards include transformer capacity limits based on device condition (e.g., transformer windings) contingency or overload limits, and feeder tie transfer loading limits. The DGP identifies the year in which substation transformer or feeders reach or exceed 90 and 100 percent of equipment capacity limits.

Guidehouse first reviewed Kentucky Power's historical summer and winter system peak demands for the past 10 years. Figure 17 indicates peak demand has decreased commensurate with the decline in the number of customers over the past 10 years.[23] Except for investments required to serve localized increases in demand, the need for distribution substation and feeder capacity investment was invariably low during this period.

Figure 17. 10-Year Historical System Peak Demand



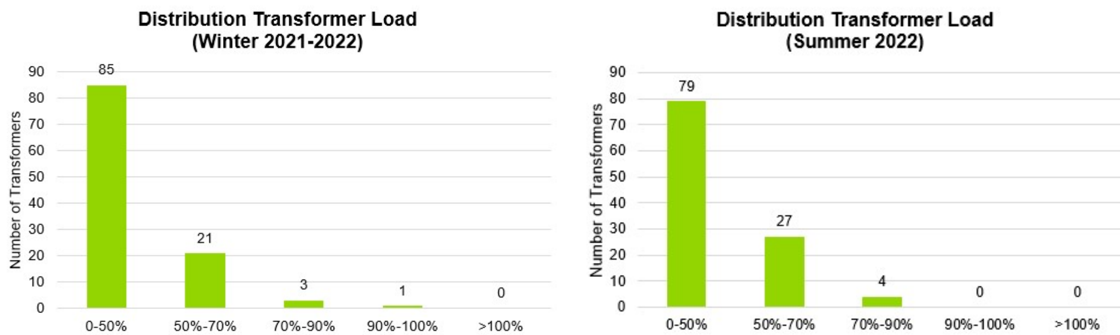
Source: Date provided by KPCO

To confirm the premise that minimal capacity investments were required over the past 10 years, Guidehouse reviewed Kentucky Power's actual and equipment loadings as of December 2022. Figure 18 presents 2022 actual substation transformer loadings as a percentage of distribution capacity limits. The chart indicates that only four of over 100 transformers are approaching 90 percent of summer capacity limits, while one is above 90 percent for winter, and none are overloaded during winter or summer. About 70 percent are below 50 percent of loading limits.

[23] The number of customers served has dropped from about 172,138 in 2013 to 164,184 in 2022, a 4.6% decline in the past 10 years.

These results confirm that historically, Kentucky Power had limited need for significant investment in capacity upgrades over the next 10 years. Recognizing that customer growth and peak loads have declined over the past 10 years, similar loading patterns can be inferred for prior years. Further, interruption data presented in Table 3 indicates the virtual absence of outages caused by substation transformer or circuit overloads.[24] Given these findings, it is unlikely feeder overloads over the past 10 to 12 years have had a material impact on reliability performance and indicate that Kentucky Power has made an appropriate level of capacity-related investments.

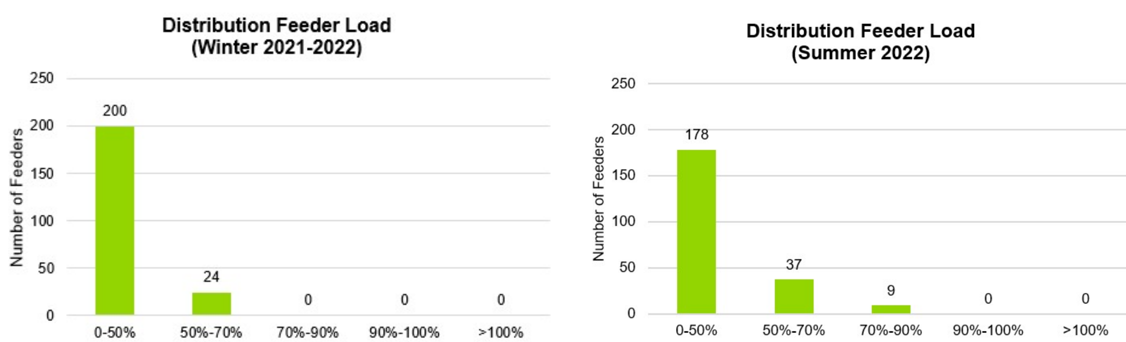
Figure 18. Kentucky Power Substation Transformer Loading (Winter 2021-2022 and Summer 2022)



Source: Date provided by KPCO

Similar to substation transformers, Kentucky Power's distribution feeders are well within capacity loading limits, with most feeders loaded to below 50 percent of capacity limits, and none expected to exceed 100 percent. Figure 19 presents actual Kentucky Power feeder loadings for 2022. Many feeders are expected to remain loaded below 50 percent over the 10-year forecast, with none exceeding 100 percent. Further, interruption data from Table 3 confirms the absence of outages caused by feeder overloads. Given these findings, it is unlikely feeder overloads over the past 10 to 12 years have had a material impact on reliability performance and indicate that Kentucky Power made the appropriate level of investment.

Figure 19. Distribution Feeder Loading (Winter 2021-2022 and Summer 2022)

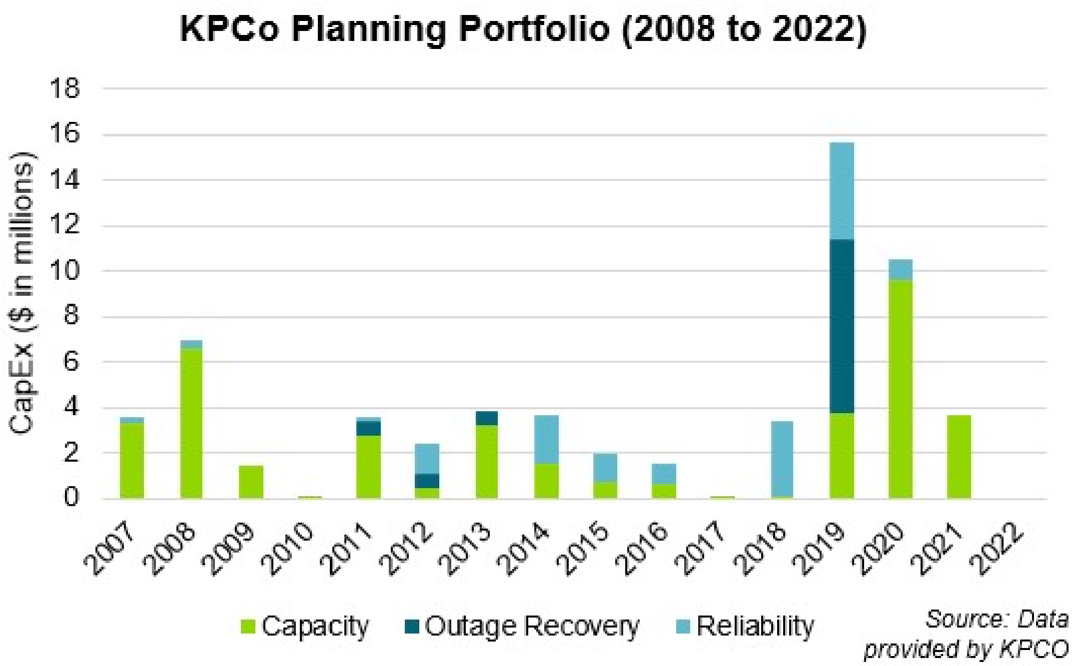


Source: Date provided by KPCO

[24] For example, of the three distribution substation transformer failures over the past 10 years, none resulted in customer interruptions as incipient failures were detected prior to actual full failure, and Kentucky Power was able to proactively replace or repair the device.

Table 5 lists distribution substation and feeder capacity investments Kentucky Power has made over the past 15 years. It excludes capacity investments required to serve new customers such as transformers and line extensions. Notably, the level of capacity-related investments was modest compared to other investment categories due to the decline in load growth as noted above. While some investments were needed solely to serve localized increases in demand, such as new load centers, other investments were undertaken to improve reliability performance while increasing capacity. Of the total 15-year capital investment of $71 million, approximately 34 percent was for joint capacity/reliability projects. Guidehouse concludes balancing of capacity and reliability investments over the past 15 years is consistent with good utility practice and Kentucky Power's documented planning procedures.

Table 5. Capacity Investments: 2008 - 2022



Summary Assessment: *Kentucky Power's distribution planning processes and equipment loading practices are consistent with or exceed industry practices. The steps that planners follow to justify and receive approval for capacity investments is based on engineering-based solutions designed to achieve least cost outcomes. Substation and distribution equipment loading criteria is based on capacity limits that recognize normal and contingency acceptable loadings – summer and winter - that minimize the likelihood of failure due to overload while maximizing the available capacity from these assets. The virtual absence of outages over the past several years caused by failures due to overloads confirms Kentucky Power has judiciously monitored loadings. Decreased peak demand has caused equipment loading to remain well below limits, while the absence of capacity overloads confirms that Kentucky Power has not under-invested in distribution capacity. Further, Kentucky Power has made capacity investments that jointly enhance reliability, demonstrating an appropriate balancing of investments to meet both capacity and reliability needs.*

Engineering and Design Standards

Kentucky Power's distribution system is comprised of long distribution lines that serve low customer density and remote load centers.[25] Most distribution feeders serving higher load density areas such as those in the Ashland district are rated 12.47kV while lines serving rural areas and remote loads are rated 34.5kV.[26] Table 6 summarizes Kentucky Power's distribution system properties by voltage class for each of their three districts. A substantial percentage of distribution feeders serving rural load are rated 34.5kV, a higher voltage rating often used by electric utilities serving rural or remote load centers. Feeders rated 34.5kV are designed for higher circuit loadings with less voltage variability compared to lower voltage lines (e.g., 12.47kV). However, Kentucky Power's 34.5kV lines are more susceptible to interruptions due to longer average length and higher voltage - higher voltage are more susceptible to sustained faults from tree contact due to lower flashover distances - compared to lower voltage lines.

Table 6. Kentucky Power Distribution System Properties

Kentucky Power Special District	Voltage Class	Total Miles of Primary Line[27]	Avg Line Length (mile)	Avg # of Customers	Avg # of Reclosers / Sectionalizers	Avg # of Regulators
Ashland	12 kV	1,957	31	758	9.1	2.3
	34 kV	591	59	928	17.5	5.2
Hazard	12 kV	681	30	683	12.0	3.2
	34 kV	1,836	57	779	15.5	4.2
Pikeville	12 kV	1,699	23	566	9.8	2.5
	34 kV	1,482	55	1,001	16.1	2.9
Total System	12 kV	4,348	27	648	9.7	2.4
	34 kV	3,908	57	888	16.0	3.8
	Total	**8,245**	**36**	**722**	**11.6**	**2.9**

To mitigate increased outage exposure, over the several years Kentucky Power has proactively installed reclosers and sectionalizers to limit outages - Table 6 highlights the large number of sectionalizing devices installed, particularly for longer 34.5kV circuits. Further, Kentucky Power recently has installed auto sectionalizing schemes to transfer unfaulted line sections to adjacent feeders to improve reliability performance. Up to 25 percent or greater of feeder capacity is reserved for load transfers on lines where auto sectionalizing schemes are located, consistent with utility practices.

About 25 percent of Kentucky Power's substations have two or more transformers capable of transferring load to the un-faulted device in the event of a device failure or bus fault. The remaining substations typically are those serving remote load centers or that are lightly loaded. For the latter, Kentucky Power uses mobile substation transformers to provide back-up in the event of a transformer failure at substations equipped with a single device. As noted earlier, Kentucky Power establishes transformer capacity limits based on loading criteria, transformer

[25] Historically, Kentucky Power's distribution system was designed to serve remote mining load, several of which have discontinued operations.
[26] Many distribution feeders rated 34.5kV (at the substation source) also serve load at lower voltage. These feeders include 34.5/12.47kV three-phase or 19.9kV / 7.2kV single-phase stepdown transformers located downstream of the substation.
[27] Line miles for circuits rated 34.5kV include downstream line segments that are stepped to lower voltages such as those rated 12.47kV.

type, condition, and number of devices; for the latter, Kentucky Power loads unfaulted transformers to a higher emergency rating with acceptable loss of life derived based on IEEE transformer loading guidelines.[28] Guidehouse's prior experience with similar utilities confirms that each of Kentucky Power's design and equipment loading practices described above is consistent with utilities with comparable service territory characteristics and distribution feeder properties.

Distribution feeders that provide capacity back-up to adjacent substations or that are part of an automated sectionalizing scheme (e.g., Distribution Automation Circuit Reconfiguration (DACR)) may be assigned lower loading limits, such as 75 percent of normal rating. Due to the length and location of a subset of distribution feeders serving rural load centers, the ability to transfer faulted lines sections to adjacent feeders is limited and usually is cost prohibitive to extend or upgrade line sections to enable load transfers. As of December 2022, Kentucky Power has installed five transfer schemes covering approximately 25 substations and 50 circuits on its distribution system.[29] Guidehouse views Kentucky Power efforts as consistent with leading utility practices as outlined in Table 7, which indicates several utilities are in the early stages of adopting DACR via Fault Location, Isolation, and Service Restoration (FLISR) while these schemes are already in place at Kentucky Power.

Table 7. Fault Isolation Benchmark Summary

Fault Isolation Scheme	Wide-Scale Basis	Next 5 Years	Pilot Program	Pilot Next 5 Years	Not Planned
Remote control of line switches and reclosers	17	3	0	0	0
Automated Fault Location, Isolation and Service Restoration (FLISR)	12	5	0	2	1

In 2015 Kentucky Power adopted the National Electric Safety Code (NESC) heavy loading distribution system design standard.[30] The higher design standard includes installation of higher-class poles, shorter spans, increased guying and equipment rated to withstand higher wind and ice loadings. Application of the higher design standard is applied on a selective basis - some locations are not suitable for the higher design standard, such as single pole replacements or where existing pole locations prohibit mid-span placement of poles with shorter spans. The transition to the heavy loading standard, over time, will enhance resiliency for major storm events, and it is viewed by Guidehouse as one that will enhance the resiliency of Kentucky Power's distribution system.

Grid Modernization

In addition to the adoption of the NESC heavy loading design standard, Kentucky Power has undertaken grid modernization and storm hardening initiatives to improve reliability and spending efficiency – each are central to Kentucky Power's Distribution Asset Management Program. Key among these is the installation of reclosers and sectionalizing devices, of which five are included in DACR and feeder tie transfer schemes installed over the past few years.

[28] IEEE Standard C57. 12.00: IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.
[29] Totals include fully automated and manually controlled switches and reclosers.
[30] Per NESC maps, Kentucky Power's service territory is located in a Medium loading zone.

Kentucky Power previously invested $3,463,115 in DACR. Kentucky Power now proposes to install additional DACR schemes as part of proposed DRR investments, which Guidehouse concludes will further improve reliability performance. Kentucky Power is also proposing other reliability enhancements such as installation of new feeder ties in conjunction with the installation of new substation or power transformers and reconfiguration of distribution circuits to reduce outage exposure.

Table 8 presents Kentucky Power's proposed spending plan on grid hardening and modernization initiatives included in the DRR. Up to $40 million (capital) along with $1.1 million (O&M) is proposed annually over the next five years, which Guidehouse concludes will materially improve reliability as measured by SAIFI and SAIDI indices.

Table 8. Proposed Grid Modernization Initiatives Under the DRR

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

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

Source: Everett Phillips Direct Testimony – p. 35

Summary Assessment: *Kentucky Power's engineering design and equipment selection criteria meet or exceed industry practices, particularly for electric utilities with comparable service territory characteristics and distribution system properties. Kentucky Power's distribution system design and equipment loading practices conform to system wide standards and criteria set forth by AEP, which Guidehouse views as consistent with good utility practices.*[31] *Substation transformer loading limits are based on industry-accepted standards outlined in IEEE guidelines while distribution feeder loading limits are based on tie transfer criteria and automated transfer schemes, where applicable. The transition to a higher design standard meets or exceeds utility practices and over time, will improve reliability performance during storms and normal outage events. Grid modernization initiatives proposed in the DRR have proven successful in prior applications and will further improve reliability if approved in Kentucky Power's pending rate filing.*

2.5 Equipment Maintenance and Inspections

Distribution Circuits

Similar to its capacity planning documentation, Kentucky Power equipment maintenance practices, procedures and schedules follow those documented in AEP manuals that apply to all operating companies. Guidehouse reviewed these procedures for several substation and distribution feeder equipment categories for consistency with good industry practices. We also benchmarked Kentucky Power practices with those of other comparable utilities. Guidehouse also reviewed programmatic maintenance or equipment replacements such as those outlined in the DRR.

The following sections describe Kentucky Power's distribution substation and circuit inspection and maintenance practices, and its compliance with completing each on schedule. It also highlights storm hardening and programmatic enhancement designed to improve reliability during normal outage events and major storms. The results of our review and assessment follows for each distribution category of lines or equipment.

1. **Distribution Circuit Inspections**

   Kentucky Power inspects each of its distribution feeders every two years, consistent with the Kentucky Public Service Commission's requirements outlined in the *Guidelines for Circuit Inspection* document. For overhead and underground lines, Kentucky Power follows the *Distribution Overhead/Underground Circuit Facilities Inspection and Maintenance* guidelines. Kentucky Power documents the results of its inspections electronically, highlighting abnormalities that require follow-up up mitigation.

   Guidehouse notes that the 2-year inspection requirements exceed industry practices, as some utilities have longer inspection cycles (3 to 5 years); in some instances, inspections are performed only on an as needed basis or during crew off-times. The inspection program has produced favorable results that have improved reliability. Table

[31] The AEP design standard recognizes locational factors that are unique or need to be considered for individual operating companies such as highly rural segments of Kentucky Power's distribution system where feeder ties to other substations may not be practical or cost prohibitive.

9 presents the quantity and cost of repairs resulting from circuit inspections, with up to $1 million spent annually for repairs.

Table 9. Inspection Repairs

Year	Circuit Repairs	Total Cost
2016	277	$925,998
2017	1096	$629,831
2018	323	$910,896
2019	850	$949,315
2020*	667	$569,649
2021*	530	$489,629
2022	1,232	$573,721
Total	**4,975**	**$5,049,040**

*Inspections, along with other maintenance activity, was impacted by Covid-19

2. Distribution Line Reclosers, Capacitors and Regulators

Along with other key equipment, Kentucky Power inspects distribution electronic and hydraulic reclosers between one and two years. Table 10 lists distribution line inspections completed since 2008, and confirms that Kentucky Power completes inspections on schedule.

Table 10. Distribution Equipment Maintenance - Inspections Completed

Year	Switched Cap		Fixed Cap	Recloser Electronic		Recloser Hydraulic		Regulator
	No. Inspections Completed	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices inspected	No. Inspections Completed	No. Devices Inspected	No. Inspections Completed
2008	147	91	347	259	2017	1140	550	291
2009	268	84	391	292	1879	1084	607	316
2010	303	76	395	289	1928	1109	583	307
2011	327	88	437	311	1900	1097	611	323
2012	316	80	457	327	1816	1075	641	333
2013	299	74	490	353	1854	1055	618	319
2014	296	72	516	369	2079	1169	630	326
2015	283	71	533	392	1009	604	631	327
2016	278	69	552	414	1879	1066	619	319
2017	267	63	562	423	1567	875	626	326
2018	241	59	565	432	1317	746	595	304
2019	247	58	602	458	1387	742	624	322
2020	224	56	630	479	1926	1076	618	317
2021	80	42	646	512	988	541	471	236
2022	13	20	655	530	1423	767	439	227
2023	11	22	375	300	433	250	133	75
Total	**3827**	**1165**	**8773**	**6140**	**29160**	**14396**	**9968**	**5163**

3. Pole Inspections and Replacements

Pole inspection practices, intervals and treatment criteria are outlined in AEP's *Specifications for Inspection, Groundline Treatment & Reinforcement of Standing Wood*

Poles. Inspection requirements apply to the above and below groundline inspection and groundline treatment of standing wood poles performed by qualified and licensed contractors. The specification is detailed, with actions and treatments to be undertaken for increasing levels of deterioration (e.g., compliance with NESC rejection criteria) and original versus remaining pole circumference resulting from pole rot. The specification lists numerous pole data collected via the inspections such as pole class, height, species, manufacturer along with defective pole information such as above and below ground level condition. The condition of deteriorated ancillary equipment and devices such as broken guy wires, cracked cross-arms, loose connectors, defective cutouts, broken lightning arresters and unauthorized attached also is recorded.

Comprehensive pole inspections and testing are conducted every 10 years following limited inspections for the first 10 to 30 years (newer poles typically do not experience material levels of rot), which is consistent with industry practice for poles located in a decay zone comparable to Kentucky Power. Table 11 presents the inspections completed by Kentucky Power's contractors between 2014 and 2018. Inspection results indicate almost 98 percent of poles inspected passed remaining strength criteria for continued use or that otherwise could be reinforced via pole treatment. These results are consistent with utilities for whom Guidehouse has conducted similar reviews. Pole inspections have followed the 10-year inspection schedule as of 2019.

Table 11. Pole Inspections (2014 – 2018)

Inspection Results	Quantities
Non-Reject	32,448
Non-Restorable Reject	527
Priority Non-Restorable Reject	379
Priority Restorable Reject	611
Restorable Reject	284
Unset	1
Total	**34,250**

Table 12 lists the number of poles Kentucky Power replaced resulting from the inspections, with up to three million spent annually. These capitalized amounts are exclusive of other treatment options Kentucky Power applied during inspections.

Table 12. Pole Replacements

Year	Poles Replaced	Total Cost
2016	339	$923,942
2017	178	$622,232
2018	714	$2,725,462
2019	346	$1,728,746
2020	355	$1,097,202
2021	223	$1,359,284
2022	413	$1,261,073
Total	**2,568**	**$9,717,941**

In addition to or outside of scheduled inspections, deficient poles, crossarms and leaning poles are detected during the 2-year Inspection Guidelines. Given the above level of detail, Kentucky Power inspection history and prior spending, Guidehouse concludes Kentucky Power's pole inspection practices and follow up mitigation is consistent with good utility practice.

Distribution Substations

The following subsections summarize the results of the benchmarking of Kentucky Power's substation equipment inspection and maintenance intervals versus those of the benchmark utility group. Additional details follow for major equipment categories. Table 13 confirms Kentucky Power's substation equipment maintenance cycles are consistent with benchmark utility practices.

Table 13. Substation Equipment Maintenance Benchmarks

Substation Maintenance Cycles	Average Cycle Time (12 Utilities)	Kentucky Power	Kentucky Power Comments
Power Transformers	5.1	4/5/8/10	Varies by transformer type
Relays	5.6	--	Follows NERC compliance
DC Supply (Batteries)	N/A	1	Annual detailed inspection
Circuit Breakers	5.6	6	For most breaker types

1. Substation Transformers

Transformer inspection and maintenance is performed by Kentucky Power Transmission Field Services (TFS), with specific procedures outlined in AEP's *Transformer Maintenance Work Standard Practices* document. The document is comprehensive, and it lists major inspection and overhaul intervals and maintenance activities along the specific details for conducting dissolved gas in oil analyses, including increasing levels of risk classification associated with the results of the analysis along with actions to be undertaken for each level. Table 13 confirms that Kentucky Power inspection and maintenance intervals are consistent with peer group practices, while Kentucky Power confirmed via tracking reports (See Appendix for details) that substation transformer inspections have been completed on schedule, with actions undertaken to address deficiencies found through inspections.

The effectiveness of Kentucky Power's transformer inspection maintenance is confirmed by the relatively low number of transformer failures and low contribution to reliability indices. Over the last five years, Kentucky Power has only experienced three substation transformer failures in its distribution substations. Kentucky Power assesses normal loading annually at substations and conducts maintenance on power transformers per planned schedules. Kentucky Power provided records that transformer maintenance has been completed on schedule. A sample transformer inspection report highlighting maintenance cycles for transformers under Kentucky Power ownership is presented in the Appendix. Similar reports are prepared for other substation equipment..

2. Substation Circuit Breakers

Substation Circuit Breakers inspection and maintenance is performed by Kentucky Power Transmission Field Services (TFS), with specific procedures outlined in AEP's *Circuit Breaker Maintenance Work Standard Practices Procedure* document.[32] The document is comprehensive, and it lists major inspection and overhaul intervals and maintenance activities along the specific details on the level of maintenance required based on condition assessment reports, breaker type, interruption medium (e.g., gas, oil, air), voltage, with results recorded via electronic data collection.

Table 13 confirms that Kentucky Power inspection and maintenance intervals are consistent with peer group practices, while Kentucky Power confirmed via tracking reports that circuit breaker inspections have been completed on schedule, with actions undertaken to address deficiencies or abnormal readings, among other inspection results. Similar to power transformers, the effectiveness of Kentucky Power's breaker inspection and maintenance is confirmed by the relatively low number of device failures and low contribution to reliability indices.

3. Protective Relays

Protective relay inspection and testing is performed by Kentucky Power Transmission Field Services (TFS), with specific procedures outlined in AEP's Protective Relay Maintenance Practices Procedure document. The document is comprehensive, and it lists inspection, testing and calibration of electromechanical and digital relays. While the document does not specify testing schedules, it does state that Kentucky Power follows NERC relay testing compliance intervals of PRC-005.

Table 13 confirms that Kentucky Power inspection and maintenance intervals are consistent with the benchmark utility practices. Similar to distribution substation transformers, the effectiveness of Kentucky Power's relay inspection and testing program is confirmed by the relatively low number of device failures and low contribution to reliability metrics as confirmed in Table 3.

Programmatic and Targeted Replacements

Kentucky Power has implemented a series of targeted and programmatic distribution line and equipment upgrades and replacement programs to improve reliability performance, focusing on the hardening of distribution assets to better withstand major storms. Several of these programs are based on inspection reports and data obtained from outage records under the equipment cause code. Two areas where equipment failures have caused a high level of interruptions include porcelain insulator and defective fused cutouts. While the number of insulators replaced is not readily available (insulators are not unit of property and therefore not individually tracked), Kentucky Power has replaced large quantities of defective fused cutouts over the past several years, highlighted in Table 14.

[32] Practices apply to devices located both within and outside the substation fence.

Table 14. Fused Cutout Replacements

Year	No. of Cutouts Replaced	Total Investment Cost
2016	2387	$679,184
2017	2688	$862,032
2018	4,464	$1,555,841
2019	3,817	$1,580,662
2020	1,270	$438,995
2021	1,334	$335,180
2022	1,413	$371,261
Total	**17,373**	**$5,823,155**

In addition to the above and pole replacement, Kentucky Power has replaced defective equipment in several other areas as part of its grid modernization and reliability improvement programs. Table 15 summarizes amounts spent over the past three years for several of these programs.

Table 15. Equipment Replacement Programs (2020 – 2022)

Year	Storm Hardening	Reliability Projects	Small Wire Replacements	Spacer Cable Replacements	Station Line Projects
2020	$434,710	$--	$259,700	$--	$--
2021	$--	$370,444	$499,850	$710,000	$150,000
2022	$--	$1,015,913	$--	$--	$--
Total	**$434,710**	**$1,386,357**	**$759,550**	**$710,000**	**$150,000**

Summary Assessment: *Kentucky Power's equipment maintenance procedures and scheduling meet or exceed industry practices. Kentucky Power's maintenance intervals, inspection, and testing practices align with those set forth by AEP, which Guidehouse views as consistent with good utility practices. Procedures for substation transformers, breakers, protective relays, and ancillary equipment are comprehensive and recognize differences in equipment type, supplier and performance history; while distribution circuit practices, including full circuit inspections, meet or exceed industry practices as confirmed via benchmarking analysis. Furthermore, Kentucky Power has proactively addressed equipment condition or performance issues over the past several years through spending programs that aim to achieve maximum reliability benefits; and proposes to further advance these programs via its proposed Distribution Reliability Rider.*

2.6 Storm Restoration Procedures and Performance

Restoration Procedures

Guidehouse's independent assessment of Kentucky Power's storm performance includes an extensive review of Kentucky Power's emergency and storm procedures, Incident Command

System (ICS) and various other factors to support our findings. We interviewed Kentucky Power personnel responsible for Emergency Response to confirm our understanding and review of Kentucky Power's practices and how decisions are made to ensure that procedures are in place and followed during storm events. Guidehouse's evaluation and assessment addresses the following topics and questions.

- What are the roles and responsibilities of Kentucky Power's personnel and outside contractors during major storms and events?
- Are storm restoration activities centralized or decentralized?
- Is the deployment of the Incident Command System (ICS) consistent with utility good practices and for processes, practices, what are the roles/responsibilities?
- What are Kentucky Power's processes for pre-storm preparation and notification?
- What processes are used for damage and hazard assessment?

Based on Guidehouse assessment, Kentucky Power has a comprehensive Emergency Response Plan (ERP) to safely restore electric service to customers as quickly as possible. Kentucky Power's ERP is in line with industry best practices. It includes procedures for pre-storm plans, an Incident Management Team structure, restoration procedures and storm outage reporting procedures for customers, governmental agencies, and Media.

Kentucky Power's ERP allows the flexibility to adjust activities and personnel assignments to enable more efficient storm restoration efforts as events evolve. Though storm restoration efforts are mostly centralized, when the number of outages per district reaches certain thresholds, some activities are decentralized for higher efficiency. One example of this is the options to enable Trouble dispatchers per district while keeping Central dispatchers for upstream issues and items that require broader visibility of the system.

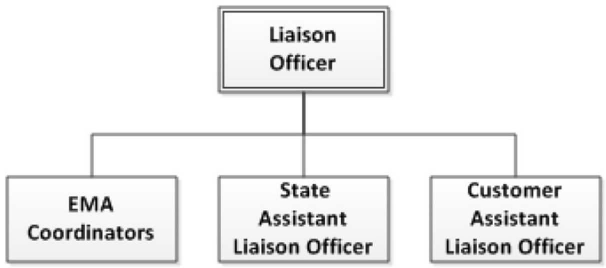
In terms of pre-storm preparations, Kentucky Power follows industry best practices which includes conducting annual Storm-Preparedness employee training, utilizing a weather prediction model, establishing mutual assistance programs and channels of communications with the public, including Federal, State and Local entities as well as with customers and media. The Storm-Preparedness trainings include comprehensive and refresher programs for every position identified in the ERP.

Kentucky Power's ICS training includes storm scenarios and associated responses. In addition, the ICS trainings require KPCO employees to simulate the expected actions that would occur in real storms to make assessment of damages, required crews and actions required.

Kentucky Power's mutual assistance programs expand beyond internal agreements within AEP operating companies to external utilities across other states, and is a member of the EEI Mutual Assistance Program and various Regional Mutual Assistance Groups (RMAGs). As part of preparing for a storm, Kentucky Power leverages its weather prediction model to estimate the probability of the event occurring to start mobilizing and stagging its personnel and equipment.

In terms of coordination and communication with the public, the ERP includes a Response Organization to ensure that the Emergency Management Agency (EMA) as well as local government and customers are kept informed and that there are two-way communications where needed. The Response Organization includes roles for the following: Liaison Officer, EMA Coordinators, State Assistant Liaison Officer and Customer Assistant Liaison Officer as illustrated in Figure 20.

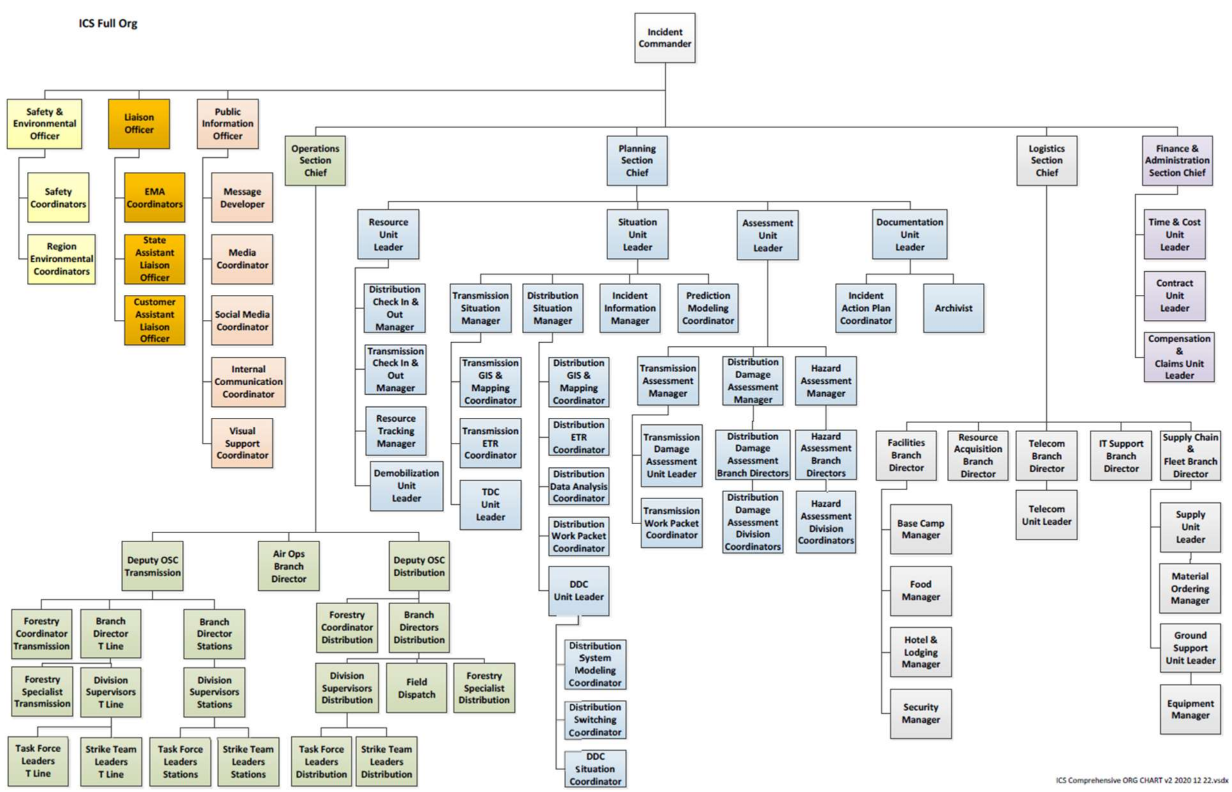
Figure 20. Response Organization- Liaison Officer



Source: KPCO ERP

Kentucky Power's ICS delineates roles and responsibilities based on employees' skills, competencies, and training to ensure safe and timely emergency response and restoration. Each role has a clear reporting structure, required training and role description, and is documented in AEP's ICS Roles and Responsibilities version 4-03. The ICS structure chart is presented in Figure 21, and is an example of how Kentucky Power's processes enable employees to expediently mobilize to their designated Storm roles to support rapid and safe restoration of its customers.

Figure 21. ICS Structure- ICS Complete Organizational Chart



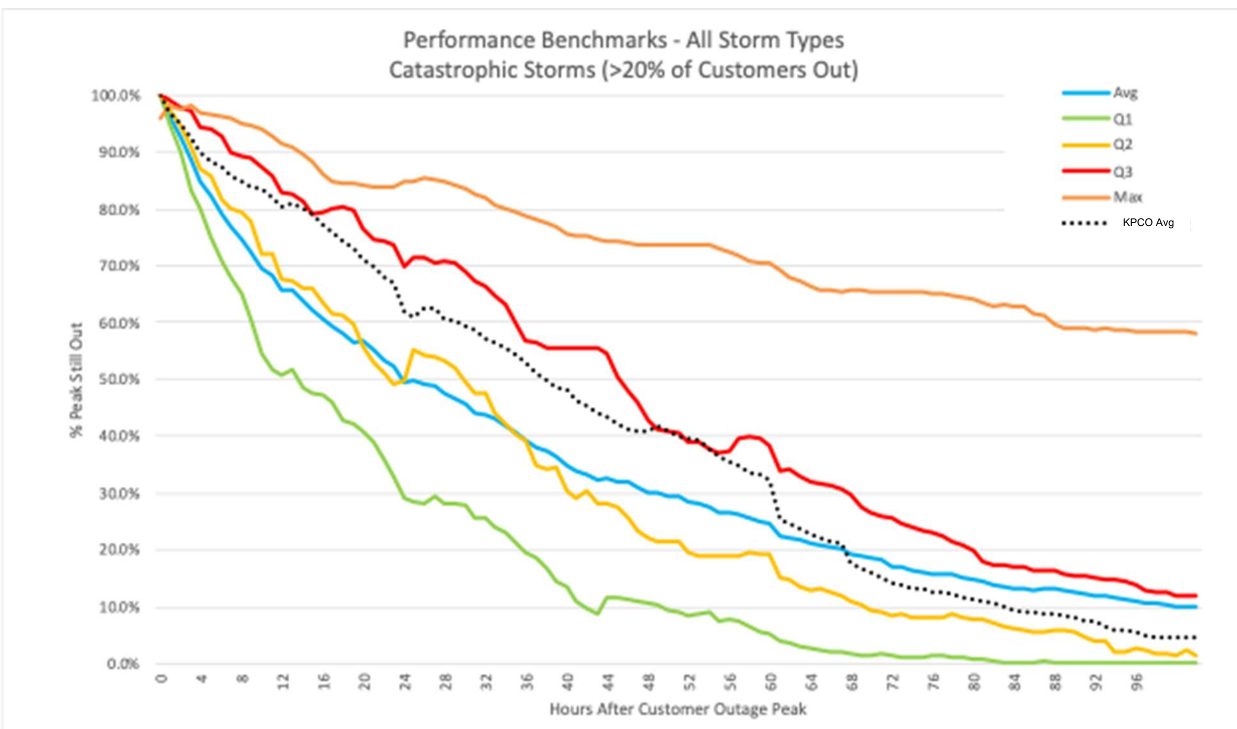
Source: KPCO ICS

Storm Restoration Performance

Guidehouse conducted storm performance benchmarking for an extensive peer group of U.S. utilities to assess how efficiently Kentucky Power restores power to customers in terms of cost and restoration times. The benchmark analysis includes storms where 20 percent or more of the customers base are interrupted. The analysis considers all major storm types such as weather conditions (i.e., snow, thunderstorms, ice, and wind).

Figure 22 compares Kentucky Power's restoration times versus industry performance benchmarks. It confirms that Kentucky Power, via adherence to their Emergency Response Program, restored a substantial percentage of their customers in a timeframe similar to that of other utilities across the U.S. Results indicate that Kentucky Power's storm performance over the past 15 years falls within the average response times of U.S. utilities, and most restoration times for Kentucky Power falls within the range of the industry benchmark. Kentucky Power's restoration times are expected to decrease following the planned installation of additional DACR schemes proposed in the Distribution Reliability Rider.

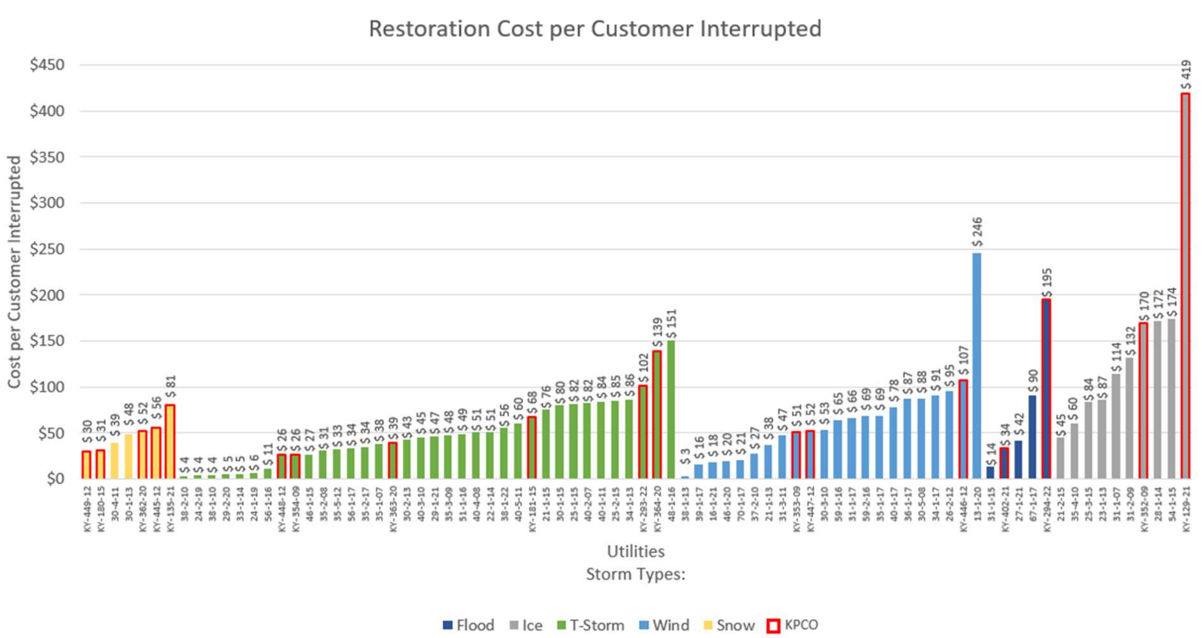
Figure 22. Kentucky Power Restoration Times Versus Industry Benchmark



Source: First Quartile Consulting and KPCO

Figure 23 is a comparison of Kentucky Power restoration costs versus industry benchmark. (Individual storm restoration costs appear in the Appendix,) This shows that compared to other Utilities, Kentucky Power restoration costs ranges are closer to the average for some storms such as wind and snowstorms. For ice storms, Kentucky Power restoration costs are above average. This is likely the result of the large amount of ice build-up in its service area during recent ice storms and more extensive tree coverage (per Table 2, Kentucky Power at 99 percent has among the highest percent of tree coverage among the peer group), and likely resulted in greater damage and more costly repairs compared to prior storms.

Figure 23. Kentucky Power Restoration Costs Versus Industry Benchmark



Source: First Quartile Consulting and KPCO

3. Conclusions

From its detailed review and analysis of data covering the period 2008 to current, industry benchmark data for utilities with comparable service territories and distribution systems, and interviews with Kentucky Power, Guidehouse offers the following findings and conclusions.

Kentucky Power's,

- Distribution system is located in a region with among the highest tree coverage and density for the peer group of electric utilities, with low customer density and high average circuit length, each of which are contributing factors to reliability performance;
- Reliability performance as measured by System Average Interruption Frequency Index (SAIFI) is within the peer group average. Reliability performance as measured by System Average Interruption Duration Index (SAIDI) is slightly above the peer group average;
- Tree-related customer interruptions from outside the right-of-way (TOR) is the leading cause of outages. Efforts are underway and Kentucky Power proposes to reduce TOR interruptions via incremental investments under its proposed Distribution Reliability Rider (DRR);
- Spending on capital projects and maintenance is at or above the peer group average, which is notable for a utility that has experienced a decrease in customers and demand;
- Vegetation management practices are at or above industry practices, with trimming completed on schedule and clearances based on species type and location;
- Equipment failures are the second leading cause of customer interruptions. Proactive efforts to reduce customer interruptions via replacement of equipment with high failure rates (such as cutouts and insulators) are underway. Kentucky Power proposes to expand its ongoing replacement program through incremental investments under the proposed DRR;
- Capital spending on distribution assets as measured by total distribution investments and number of customers is at or above industry averages, which is notable as Kentucky Power has experienced a decline in load growth and number of customers served;
- Spending on distribution maintenance as measured by distribution line miles and number of customers is at or above industry averages;
- Equipment maintenance practices, procedures and inspection intervals is consistent with industry practices, with inspection cycles completed on time;
- Emergency restoration procedures, which include a centralized Incident Command structure, are consistent with industry practices; and
- Storm restoration intervals as measured by customers restored over storm duration, and restoration costs are within industry averages for most types of storms (e.g., wind and snow), except ice storms where costs are higher due to tree density and storm severity.

Appendices

Candidate Peer Group Utilities

#	Utility	State	Type	Service Territory Tree Coverage	Customer Count[33]	Criteria 1 *(State)*	Criteria 2 *(Type)*	Criteria 3 *(Urban / Rural)*	Criteria 4 *(>85%)*	Criteria 5 *(>10,000)*
1	Appalachian Power Co	KY	IOU	--	--	✓	✓			
2	Barton Village, Inc	VT	Municipal	--	--	✓				
3	Big Sandy Rural Elec Coop Corp	KY	Cooperative	100%	12,778	✓	✓	✓	✓	✓
4	Blue Grass Energy Coop Corp	KY	Cooperative	75%	--	✓	✓	✓		
5	Central Maine Power Co	ME	IOU	95%	634,601	✓	✓	✓	✓	✓
6	City of Bowling Green - (KY)	KY	Municipal	--	--	✓				
7	City of Burlington Electric - (VT)	VT	Municipal	--	--	✓				
8	City of Frankfort - (KY)	KY	Municipal	--	--	✓				
9	City of Glasgow - (KY)	KY	Municipal	--	--	✓				
10	City of New Martinsville - (WV)	WV	Municipal	--	--	✓				
11	City of Owensboro - (KY)	KY	Municipal	--	--	✓				
12	City of Paducah - (KY)	KY	Municipal	--	--	✓				
13	City of Princeton - (KY)	KY	Municipal	--	--	✓				
14	Clark Energy Coop Inc - (KY)	KY	Cooperative	77%	--	✓	✓	✓		
15	Craig-Botetourt Electric Coop	WV	Cooperative	94%	484	✓	✓	✓	✓	
16	Cumberland Valley Electric, Inc.	KY	Cooperative	98%	23,831	✓	✓	✓	✓	✓
17	Duke Energy Kentucky	KY	IOU	89%	142,504	✓	✓	✓	✓	✓
18	Eastern Maine Electric Coop	ME	Cooperative	96%	12,708	✓	✓	✓	✓	✓
19	Farmers Rural Electric Coop Corp - (KY)	KY	Cooperative	76%	--	✓	✓	✓		
20	Fleming-Mason Energy Coop Inc	KY	Cooperative	82%	--	✓	✓	✓		
21	Grayson Rural Electric Coop Corp	KY	Cooperative	98%	14,813	✓	✓	✓	✓	✓

[33] Ten-year average (2013-2022). Calculated using customer data from the U.S. Energy Information Administration. Source: Annual Electric Power Industry Report, Form EIA-861 detailed data files

22	Green Mountain Power Corp	VT	IOU	94%	264,575	✓	✓	✓	✓	✓
23	Harrison Rural Elec Assn, Inc	WV	Cooperative	98%	6,884	✓	✓	✓	✓	
24	Henderson City Utility Comm	KY	Municipal	--	--	✓				
25	Inter County Energy Coop Corp	KY	Cooperative	78%	--	✓	✓	✓		
26	Jackson Energy Coop Corp - (KY)	KY	Cooperative	96%	51,119	✓	✓	✓	✓	✓
27	Jackson Purchase Energy Corporation	KY	Cooperative	72%	--	✓	✓	✓		
28	Kenergy Corp	KY	Cooperative	65%	--	✓	✓	✓		
29	Kentucky Power Co	KY	IOU	99%	166,243	✓	✓	✓	✓	✓
30	Kentucky Utilities Co	KY	IOU	72%	--	✓	✓	✓		
31	Liberty Utilities (Granite State Electric)	NH	IOU	98%	44,932	✓	✓	✓	✓	✓
32	Licking Valley Rural E c	KY	Cooperative	99%	17,327	✓	✓	✓	✓	✓
33	Louisville Gas & Electric Co	KY	IOU	88%	--	✓	✓			
34	Meade County Rural EC	KY	Cooperative	81%	--	✓	✓	✓		
35	Monongahela Power Co	WV	IOU	98%	388,333	✓	✓	✓	✓	✓
36	New Hampshire Elec Coop Inc	NH	Cooperative	97%	81,297	✓	✓	✓	✓	✓
37	Nolin Rural Electric Coop Corp	KY	Cooperative	75%	--	✓	✓	✓		
38	Owen Electric Coop Inc	KY	Cooperative	91%	61,365	✓	✓	✓	✓	✓
39	Pennyrile Rural Electric Coop	KY	Cooperative	70%	--	✓	✓	✓		
40	Public Service Co of NH	NH	IOU	88%	81,297	✓	✓	✓	✓	✓
41	Salt River Electric Coop Corp	KY	Cooperative	81%	--	✓	✓	✓		
42	Shelby Energy Co-op, Inc	KY	Cooperative	76%	--	✓	✓	✓		
43	South Kentucky Rural EC	KY	Cooperative	89%	68,891	✓	✓	✓	✓	✓
44	Taylor County Rural EC	KY	Cooperative	85%	26,663	✓	✓	✓	✓	✓
45	The Potomac Edison Company	WV	IOU	98%	204,050	✓	✓	✓	✓	✓
46	Town of Hardwick	VT	Municipal	--	--	✓				
47	Town of Stowe-(VT)	VT	Municipal	--	--	✓				
48	Tri-County Elec Member Corp (TN)	KY	Cooperative	90%	26,261	✓	✓	✓	✓	✓

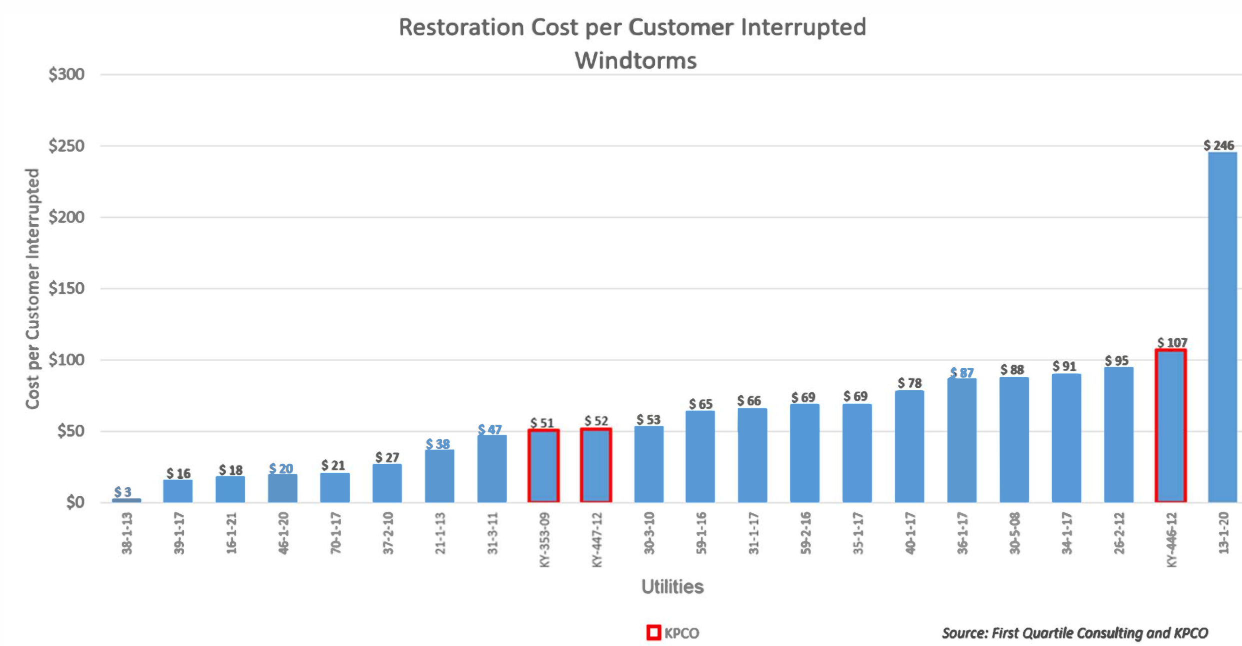
49	Unitil Energy Systems	NH	IOU	--	--	✓	✓			
50	Vermont Electric Cooperative, Inc	VT	Cooperative	90%	38,992	✓	✓	✓	✓	✓
51	Versant Power (Emera Maine)	ME	IOU	90%	164,510	✓	✓	✓	✓	✓
52	Village of Enosburg Falls - (VT)	VT	Municipal	--	--	✓				
53	Village of Hyde Park - (VT)	VT	Municipal	--	--	✓				
54	Village of Jacksonville - (VT)	VT	Municipal	--	--	✓				
55	Village of Johnson - (VT)	VT	Municipal	--	--	✓				
56	Village of Morrisville - (VT)	VT	Municipal	--	--	✓				
57	Village of Northfield - (VT)	VT	Municipal	--	--	✓				
58	Village of Orleans - (VT)	VT	Municipal	--	--	✓				
59	Warren Rural Elec Coop Corp	KY	Cooperative	76%	--	✓	✓	✓		
60	West Kentucky Rural E C C	KY	Cooperative	74%	--	✓	✓	✓		
61	Wheeling Power Co	WV	IOU	--	--	✓	✓			
					TOTAL Count	61	42	38	23	21

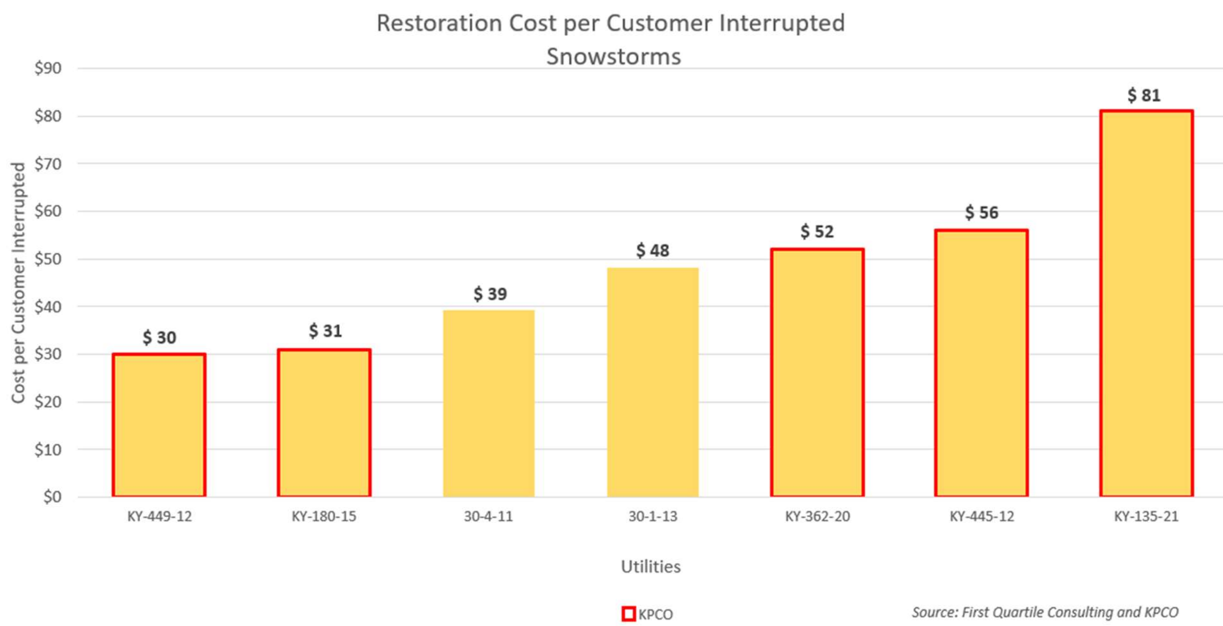
Transformer Maintenance Schedules

Operating Company	Station	Asset Name	Asset Owner	Device KV	Device Status	Commissioning Date	Maintenance Responsiblity	PT Application	Minor Maintenance Most Recent Execute Time	Minor Maintenance Current Schedul	Minor Maintenance Normal Schedul	Minor Maintenance Due Date (Current Schedule)
Kentucky Power	ALLEN (KP)	TR-1	Distribution	46 kV	In Service	5/5/1998	Transmission	Power	5/11/1998	0	0	
Kentucky Power	ASHLAND	BANK 1 300	Distribution	69 kV	In Service	12/31/1899	Transmission	Power	12/6/2012	120	120	12/6/2022
Kentucky Power	ASHLAND SERV BLD	Cap Spare Waukesha 25MVA 69-12KV	Distribution	69 kV	In Service	10/15/2018	Transmission	Power		120	120	10/15/2028
Kentucky Power	BAKER 765KV	SPARE XFMR 3	Distribution	69 kV	Spare - Capitalized	6/25/1997	Transmission	Power	10/19/2009	120	96	10/19/2019
Kentucky Power	BAKER 765KV	SPARE XFMR 2	Distribution	69 kV	Spare - Capitalized	11/8/1982	Transmission	Power	5/10/2003	120	72	5/10/2013
Kentucky Power	BAKER 765KV	SPARE XFMR 1	Distribution	69 kV	Spare - Capitalized	11/1/1991	Transmission	Power	7/6/2006	0	0	
Kentucky Power	BARRENSHE	TR-1	Distribution	69 kV	In Service	1/1/1994	Transmission	Power	10/2/2023	120	120	10/2/2033
Kentucky Power	BEAVER CREEK	#9 BANK DISTRI	Distribution	138 kV	In Service	5/15/2007	Transmission	Power	4/9/2020	120	120	4/9/2030
Kentucky Power	BECKHAM	TR-1	Distribution	138 kV	In Service	12/14/2005	Transmission	Power	10/30/2017	120	120	10/30/2027
Kentucky Power	BEEFHIDE	TR 1	Distribution	138 kV	In Service	1/26/1994	Transmission	Power	2/14/2022	120	120	2/14/2032
Kentucky Power	BELFRY	1 DISTRI	Distribution	46 kV	In Service	12/31/1977	Transmission	Power	12/9/2019	72	72	12/9/2025
Kentucky Power	BELHAVEN	TRF 1 300	Distribution	138 kV	In Service	3/1/1986	Transmission	Power	10/5/2020	120	120	10/5/2030
Kentucky Power	BELLEFONTE	BANK-6 300	Distribution	138 kV	In Service	11/1/1971	Transmission	Power	12/1/2012	120	120	12/1/2022
Kentucky Power	BIG SANDY 138KV	BANK- 4	Distribution	138 kV	In Service	8/22/2007	Transmission	Power	9/20/2018	120	120	9/20/2028
Kentucky Power	BIG SANDY 138KV	BANK-3 7005	Distribution	138 kV	In Service	11/1/1984	Transmission	Power	7/23/2014	120	120	7/23/2024
Kentucky Power	BLUE GRASS	TR-1	Distribution	69 kV	In Service	4/17/1995	Transmission	Power	9/19/2018	72	72	9/19/2024
Kentucky Power	BONNYMAN	#1 BANK	Distribution	69 kV	In Service	2/23/2012	Transmission	Power		120	120	2/23/2022
Kentucky Power	BREAKS	TR-2	Distribution	69 kV	In Service	1/19/2016	Transmission	Power		120	120	1/19/2026
Kentucky Power	BULAN	1 BANK DISTRI	Distribution	69 kV	In Service	6/11/1980	Transmission	Power	7/20/2017	72	72	7/20/2023
Kentucky Power	BURDINE	TR-1	Distribution	46 kV	In Service	5/16/1998	Transmission	Power	5/20/1998	0	0	
Kentucky Power	BURTON	#1 BANK #1 BNK (TO BE REMOVED)	Distribution	46 kV	In Service	8/16/2001	Transmission	Power	8/16/2001	0	0	
Kentucky Power	BUSSEYVILLE	TR 2	Distribution	138 kV	In Service	3/12/2008	Transmission	Power	5/15/2018	120	120	5/15/2028
Kentucky Power	BUSSEYVILLE	TR 1 300	Distribution	138 kV	In Service	7/1/1978	Transmission	Power	6/27/2014	120	120	6/27/2024
Kentucky Power	CANNONSBURG	Transformer #1	Distribution	69 kV	In Service	10/31/2018	Transmission	Power		48	48	10/31/2022
Kentucky Power	CEDAR CREEK	TR 2	Distribution	138 kV	In Service	9/13/2019	Transmission	Power		120	120	9/13/2029
Kentucky Power	CEDAR CREEK	CAPITALIZED SPARE	Distribution	138 kV	Spare - Capitalized	11/10/1982	Transmission	Power	10/9/2013	72	72	10/9/2019
Kentucky Power	CEDAR CREEK	CAPITALIZED SPARE	Distribution	138 kV	Spare - Capitalized	11/10/1982	Transmission	Power	10/9/2013	72	72	10/9/2019
Kentucky Power	CHAVIES	1 BANK DISTRI	Distribution	69 kV	In Service	5/4/1986	Transmission	Power	5/1/1999	0	0	
Kentucky Power	COALTON	BANK-1 300	Distribution	69 kV	In Service	6/1/1979	Transmission	Power	1/8/2020	72	72	1/8/2026
Kentucky Power	COLEMAN	2 BANK DISTRI	Distribution	69 kV	In Service	1/1/1989	Transmission	Power	3/22/2004	120	120	3/22/2014
Kentucky Power	COLEMAN	1 BANK SINGLE	Distribution	69 kV	In Service	2/3/1994	Transmission	Power	9/1/1994	0	0	
Kentucky Power	COLLIER	1 BANK DISTRI	Distribution	69 kV	In Service	1/1/1977	Transmission	Power	7/23/2019	120	120	7/23/2029
Kentucky Power	DAISY	1 BANK DISTRI	Distribution	69 kV	In Service	10/16/1989	Transmission	Power	7/24/2003	0	0	
Kentucky Power	DEWEY	2 BANK #2	Distribution	138 kV	In Service	8/7/1975	Transmission	Power	10/16/2023	48	48	10/16/2027
Kentucky Power	DRAFFIN	1 BANK DISTRI	Distribution	46 kV	In Service	8/28/1991	Transmission	Power	5/9/2023	72	72	5/9/2029
Kentucky Power	EAST PRESTONSBURG	TR-1	Distribution	46 kV	In Service	4/10/1999	Transmission	Power	7/14/2011	120	120	7/14/2021
Kentucky Power	ELWOOD (KP)	1 BANK DISTRI	Distribution	46 kV	In Service	1/1/1975	Transmission	Power	12/14/2021	120	120	12/14/2031
Kentucky Power	ENGLE	1 BANK DISTRI	Distribution	69 kV	In Service	6/1/1994	Transmission	Power	12/24/2008	120	120	12/24/2018
Kentucky Power	FALCON	TR-T2	Distribution	69 kV	In Service	9/28/2021	Transmission	Power		120	120	9/28/2031
Kentucky Power	FEDS CREEK	1 BANK DISTRI	Distribution	69 kV	In Service	12/31/1899	Transmission	Power	7/18/2013	120	120	7/18/2023

Restoration Cost Graphs per Storm Types


Restoration Cost per Customer Interrupted
Thunderstorms
Cost per Customer Interrupted
Utilities
KPCO
Source: First Quartile Consulting and KPCO


Restoration Cost per Customer Interrupted
Windtorms
Cost per Customer Interrupted
Utilities
KPCO
Source: First Quartile Consulting and KPCO


Restoration Cost per Customer Interrupted
Snowstorms
Cost per Customer Interrupted
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
$ 30
$ 31
$ 39
$ 48
$ 52
$ 56
$ 81
KY-449-12
KY-180-15
30-4-11
30-1-13
KY-362-20
KY-445-12
KY-135-21
Utilities
KPCO
Source: First Quartile Consulting and KPCO

VERIFICATION

The undersigned, Eugene L. Shlatz, being duly sworn, deposes and says he is an independent consultant for Guidehouse, Inc., 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.

Eugene L. Shlatz

State of Ohio)
) ss. Case No. 2023-00159
County of Franklin)

Subscribed and sworn to before me, a Notary Public in and before said County and State by Eugene L. Shlatz, on 4th of December, 2023

Notary Public

My Commission Expires Feb 22nd, 2028

Notary ID Number 2023-RE-860163

NOTARY PUBLIC STATE OF OHIO

ZACHARY RAMON WILLIAMS
Notary Public
State of Ohio
My Comm. Expires
February 22, 2028