COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	))))))	**CASE NO. 2025-00113**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	))))))	**CASE NO. 2025-00114**

REBUTTAL TESTIMONY OF
PETER W. WALDRAB
VICE PRESIDENT, ELECTRIC DISTRIBUTION
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: September 30, 2025

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INTRODUCTION

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

A. My name is Peter W. Waldrab. I am Vice President for Electric Distribution for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 6900 Enterprise Drive, Louisville, Kentucky 40214.

Q. What is the purpose of your rebuttal testimony?

A. I rebut certain arguments advanced by Lane Kollen, who testified on behalf of the Attorney General ("AG") and Kentucky Industrial Utility Customers, Inc. ("KIUC"), Jason W. Hoyle, a witness for Kentucky Solar Energy Industries Association ("KY SEIA"), and James Fine, a witness for Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association ("Joint Intervenors"), to the extent those intervenor witnesses offer testimony on topics I covered in my direct testimony.

First, I rebut Mr. Kollen's assertions proposing disallowance of certain vegetation management expenses in the forecast test year and proposed rejection of deferral accounting for vegetation management expenses. For reasons I explain below, those forecasted expenses are both prudent and reasonable as is the proposed accounting treatment for those expenses.

Second, I rebut Mr. Kollen's suggestion that the Commission deny forecasted expenses and deferral accounting treatment for storm restoration. Restoring power to customers after a major storm events is one of the most critical functions the Companies perform, and the expenses associated with restoration are unpredictable. The forecasted storm expense is both prudent and reasonable and should be subject to deferral accounting.

Third, I rebut the criticisms of Mr. Hoyle and Mr. Fine concerning the Companies' study and conclusions regarding zero avoided distribution capacity costs attributable to Rider NMS-2 customers.

VEGETATION MANAGEMENT

Q. Please summarize Mr. Kollen's criticisms of the Companies' forecasted expense for transmission and distribution vegetation management.

A. Mr. Kollen asserts that the Companies' forecasted transmission and distribution vegetation management expense in the test year is simply too high compared to historical levels and that vegetation management expense should be excluded from deferral accounting treatment.

Q. Do you agree with Mr. Kollen's arguments?

A. No. The forecasted vegetation management expenses for transmission and distribution are higher than recent years but the increased spending is reasonable and prudent based on the Companies' analysis and promotes reliability of the system.

Q. Please provide operational context and support for the Companies' forecasted vegetation management expense in the test year, as modified by *pro forma* adjustments to the budget.

A. Tree-related outages accounted for 30 percent of all customer interruptions over the years 2019-2023. During that same period, the frequency of tree-related outages increased 100% and outage duration increased 80% relative to the previous five-year period, 2014-2018. These outages most commonly associated with severe weather events are large drivers of the major-event-day (MED) reliability trends I discussed in detail in my direct testimony and the Distribution System Hardening and Resiliency Plan ("DSHARP") attached as Exhibit PWW-2 to that testimony.

Because vegetation is such a large driver of MED interruptions and as my direct testimony explains, the Companies recently undertook both an internal and industry benchmarking effort to optimize vegetation management practices for safety, reliability and resiliency.[1] The result of that analysis was a greater understanding of the components of the most successful vegetation management practices – those that combine cycle-based trimming with reliability enhancement such as hazard tree removal, corridor widening, and off-cycle trimming. The Companies have used the lessons learned from that analysis to develop a spending plan for vegetation management that effectively incorporates these elements. The plan does increase costs associated with vegetation management compared to historical levels but at the same time is expected to lead to greater reliability and resiliency of the system to perform well even during and after severe weather events.

Q. What specific changes to the Companies' vegetation management activities are contemplated by the new plan?

A. The *pro forma* vegetation management expenses that are part of the Companies' vegetation management plan are structured, in concert with system hardening investments, to mitigate the impact of increasingly severe weather, reducing customer disruptions. The investments address the following:

[1] Waldrab Direct, at 22-23.

- Transitioning Transmission to a reduced not-to-exceed four-year cycle (changed from a five-year cycle) to ensure vegetation is managed before it reaches critical encroachment thresholds and off rights of way trees.
- Transitioning to a not-to-exceed five-year Distribution cycle-trim (changed from a five-year average cycle-trim) ensuring more effective vegetation clearance, addressing reliability risk and reducing customer interruptions.
- Expanding Distribution hazard tree removals beyond the right-of-way to proactively address high risk trees located outside standard clearances that have proven to be the major source of storm-related outages.
- Integrating analytics to prioritize tree removal work based on risk, enabling an optimized approach that maximizes reliability benefits for customers.

Q. How do the Companies' historic vegetation management expenses compare to industry peers?

A. According to the Companies' benchmarking analysis, their annual vegetation management expense of $1,173 per mile of overhead lines in 2024 was among the lowest expense level among investor-owned utilities included in the analysis. This demonstrates that while the Companies have been good stewards of resources while prudently maintaining vegetation around transmission and distribution lines, additional resources and strategies, and associated investments, are needed due to increased storm activity and recurrence of severe weather events impacting MED reliability.

Q. Can the Companies simply defer these spending increases for transmission and distribution vegetation management to a later time period?

A. Yes, but it would not be prudent to do so. Deferring vegetation management practices has a compounding effect. Studies consistently show that for every $1 of vegetation work deferred, utilities may face costs of $1.21 after a single year of delay, or $1.39 after two years, simply to return the system to the same maintenance standard.[2] This escalation occurs because vegetation continues to grow unchecked, increasing density, size, and accessibility challenges. Crews must spend more time and resources addressing the deferred work, often requiring specialized equipment and additional safety measures. Deferring needed vegetation maintenance also presents public safety hazards and increases risk to greater outage exposure. For those reasons, deferring additional spending on transmission and distribution vegetation management would not be prudent.

Q. How will the additional spending on vegetation management benefit the Companies' customers?

A. The enhanced vegetation management activities contemplated in the plan, working in tandem with the Companies' infrastructure investments in storm hardening and resilience, are expected to lead to a significant reduction in severe weather impact to customers, at a prudent and reasonable level of expenditure even considering the *pro forma* expenses. The increased vegetation management spending on the distribution system alone is expected to avoid an additional 6,500 customer interruptions in 2026 with more than 10,000 customer interruptions avoided in 2027 and beyond. The

[2] Browning, D. M., & Wiant, H. V. (1997). *The economic impacts of deferring electric utility tree maintenance*. Journal of Arboriculture, 23(3), 106–112, https://www.eci-consulting.com/wp-content/uploads/2017/10/Deferring-Electric-Utility-Tree-Maintenance_JOA.pdf.

planned expenses will lead to greater reliability, are reasonable, and should be approved as proposed.

Q. Why is deferral accounting appropriate for vegetation management expenses?

A. As Ms. Metts states in her rebuttal testimony, the proposed deferral accounting allows the Companies to track actual vegetation management costs against the baseline included in base rates and defer any excess or shortfall for future recovery or refund, subject to Commission review. The Companies anticipate that with more robust proactive and planned vegetation management expenditures, fewer expenses will be incurred for reactive or emergency work. Deferral accounting will ensure customers can realize the savings associated with less emergency work, which is more costly and less efficient than proactive vegetation management spending.

STORM EXPENSE

Q. Please summarize the Companies' proposal for treatment of storm damages expenses in these cases.

A. Storm restoration is one of the most important functions performed by the Companies. Restoring power to customers as quickly and safely as possible after severe weather events is absolutely critical to meeting our customers' basic needs. It is also one of the most unpredictable expenses, as the severity of storms and damage to the Companies' facilities caused by storms can vary dramatically from year to year. In order to mitigate the volatility caused by storm restoration costs and for administrative efficiency, the Companies propose in these cases to net storm restoration expenses against base rates and record a regulatory asset or liability for the difference. The Companies already do this on an *ad hoc* basis for extraordinary restoration expenses associated with severe storms, subject to the Commission's review and approval. The Companies' request would apply a similar process for other storm restoration expenses while reducing administrative expenses.

Q. What are Mr. Kollen's criticisms of this proposal?

A. Mr. Kollen proposes to disallow all storm restoration expenses in the test year. Mr. Kollen expresses concern that base period expenses would be double-counted with deferred accounting and that use of the period from 2019 through 2023 for purposes of calculating an inflation-adjusted forecast for storm restoration expense resulted in a higher forecast than if a different period had been used.

Q. How do you respond to Mr. Kollen's criticism?

A. Ms. Metts' rebuttal testimony addresses the accounting aspects of Mr. Kollen's opinions, including the basis for budgeting test year storm expense. But from an operational standpoint, the deferred accounting treatment sought by the Companies in no way constitutes a double recovery of reasonably incurred storm restoration expenses. When labor resources are pulled from other maintenance activities to perform storm restoration, the labor is charged to storm restoration. It is not duplicative of labor charged to other maintenance activities, which remain unfinished by that labor resource and must later be completed by that resource or another.

AVOIDED DISTRIBUTION CAPACITY COSTS FOR NMS-2 CUSTOMERS

Q. Are there currently any avoided distribution capacity costs created by net exports from Rider NMS-2 customers?

A. None that are material for planning purposes. As my direct testimony and Exhibit PWW-3 to my testimony demonstrate, the Companies performed a study on two neighborhoods, one in KU's service territory and one in LG&E's, and assessed the impact on engineering and construction costs if 20% penetration of distributed generation for new customers was assumed. As explained in detail in the study, impacts on peak load savings were zero or near-zero due primarily to the non-coincidence of solar production with peak loads on LG&E and KU circuits.[3]

Q. Please summarize the criticisms of the intervenor witnesses on the Companies' analysis and conclusions regarding avoided distribution costs attributable to NMS-2 customers.

A. KY SEIA's witness, Mr. Hoyle, opines that: (1) avoided costs for legacy distribution assets and equipment installed before NMS-2 existed should be considered avoided costs purposes of Rider NMS-2; (2) the Companies' conditions of significant penetration of DERs and the ability to control and dispatch of DERs to realize avoided capacity costs are invalid; and (3) various aspects of the avoided distribution cost study are flawed. Mr. Fine, a witness on behalf of the Joint Intervenors, asserts that the Companies failed to follow the Commission's direction on calculating avoided distribution costs and failed to consider marginal cost savings over the lifetime of distribution assets.

Q. Do you agree with these intervenor criticisms?

A. No. And it is noteworthy that no intervenor has offered a data-driven alternative analysis or calculation of avoided distribution capacity costs attributable to the Companies' NMS-2 customers. Instead, certain intervenor witnesses have simply

[3] Waldrab Direct Testimony, Exhibit PWW-3, p.4.

offered critiques of the Companies' analysis without proposing their own framework. I will address each of those critiques in turn.

Q. Should the cost of installing or maintaining legacy distribution assets predating the advent of NMS-2 be considered as avoided costs for purposes of NMS-2 credits as Mr. Hoyle and Mr. Fine appear to suggest?

A. No. Mr. Hoyle suggests in his testimony that "it is possible for distribution generation ("DG") systems to reduce the burden on existing infrastructure posed by load growth and delay or prevent maintenance, replacement, or upgrade expenses . . . ."[4] With respect to maintenance of legacy assets, this is simply inaccurate. Regular maintenance of distribution assets has nothing to do with whether DERs are putting energy on the system. Nor do DERs on Rider NMS-2 offset the cost of installing distribution assets that predated the existence of the rate. These are sunk costs that cannot be reversed or offset by new load or generation. Finally, while the Companies acknowledge that DERs could potentially delay the need for system upgrades under the right conditions, those conditions are simply not present on the Companies' system today as discussed elsewhere in my testimony and below.

Q. Why are significant DER penetration and utility control of the dispatchability of DERs needed to achieve potential avoided capacity costs?

A. As I explained in my direct testimony, when NMS-2 customers export energy to the grid with no control over the timing or need for energy where it is put onto the system, it does not help the Companies plan for or avoid the need for capacity upgrades. Conversely, if customer-owned energy resources are controllable or dispatchable, in

[4] Hoyle Intervenor Testimony, at 43.

theory the energy from those resources could be used to serve peak demand on circuits nearing capacity to offset the need for capacity upgrades. Dispatchable distributed energy resources can also be used to manage reactive power, reducing the need for investment in voltage regulation and improving circuit capacity. But as Mr. Conroy notes in his rebuttal testimony, Rider NMS-2 does not give the Companies control over dispatchability of customer DERs and therefore does not allow them to create opportunities for the theoretical avoided distribution capacity costs I described in my direct testimony. At current levels of penetration of DERs, with no ability to control how and where the energy is dispatched, net exports from DERs simply cannot be relied upon to avoid or defer circuit capacity investments and do not achieve avoided distribution costs.[5]

Q. Please address Mr. Hoyle's allegations of deficiency with the study attached to your direct testimony as Exhibit PWW-3.

A. Use of a "clipped" solar production profile in the Companies' avoided distribution cost study was meant to present the "best case" for solar distributed generation resulting in the highest assumed capacity factor of those resources.[6] This maximizes the possibility of distributed solar resource production coinciding with system peak demand. Moreover, examination of historical solar interconnections indicates that average DC/AC ratios are typically greater than 1.0 allowing inverters to operate at their maximum power point, i.e. highest efficiency, resulting in clipped production profiles.

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[5] And even if they did, as Mr. Conroy notes in his rebuttal testimony, the means to provide incentive for customers to allow the Companies to control the dispatch of net energy exports from DERs would be in the form of other offerings or voluntary programs, not through credits in the NMS-2 rate.
[6] E.g., KU Response to KY SEIA's Supplemental Requests for Information, No. 9.

Mr. Hoyle is critical of the sample size of meters used for the study, but as explained in discovery, the Companies used all available AMI meter data on the selected circuits in their original study and updated the loading data with additional inputs in the 2025 update.[7] Mr. Hoyle does not state how a larger sample size would change the results of the customer load shapes used in the updated study. Any differences would be minor and would not change the result of the Companies' analysis.[8] Likewise, any missing interval data from the sampled meters would not significantly impact the results of the study since load shapes were averaged among multiple customers and missing data was disregarded in that calculation.

Mr. Hoyle further asserts that the selected circuits were not representative of non-coincident peak demand on circuits across the Companies' system. The Companies provided non-coincident peak data by substation and feeder in response to KY SEIA's discovery.[9] While there are variations in peak demand across different circuits, Mr. Hoyle offers no concrete evidence that such variations would affect the study's conclusions regarding the contributions of distributed solar resources to those peaks, despite having the data to perform his own calculations. The circuits were selected because they serve still developing, primarily residential areas which offer the best opportunities for concentrated solar installations. The 20% assumed PV adoption rate used in the study is higher than the solar adoption rate on any circuit in the Companies' distribution system.

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[7] KU Response to KY SEIA's Supplemental Requests for Information, No. 6(c).
[8] *Id.*
[9] LG&E Attachment to response to Ky. SEIA's Supplemental Requests for Information, No. 5(a).

Q. Did the Companies fail to follow the Commission's guidance in the 2020 rate case orders concerning calculation of avoided distribution capacity costs as Mr. Fine testifies?

A. No. In the 2020 rate cases, the Commission performed its own avoided distribution capacity cost calculation that the Companies could not replicate then and cannot replicate now.[10] While the Commission ordered certain NMS-2 export rates based on avoided distribution capacity costs which it found to be prudent and reasonable, it did not prospectively require the Companies to use a particular methodology for calculating avoided distribution capacity costs due to NMS-2 customers in the future, nor did it establish a "benchmark" for avoided distribution capacity as Mr. Fine suggests in his testimony. Regardless, Mr. Fine proposes a value for avoided distribution costs of $0.0016/kWh and $0.0023/kWh for LG&E and KU, respectively, which he asserts is an inflation-adjusted amount based on the amount calculated by the Commission in the 2020 rate cases. The Companies' calculation of avoided distribution capacity cost is based on actual data on representative circuits, and it is in fact "better data and analysis" than values extrapolated from the 2020 rate cases which no party can replicate.

Q. Does Mr. Fine's reliance on the Lawrence Berkley National Laboratory ("LBNL") paper on the locational value of DERs support his position with regard to the Companies' analysis?

A. No. The LBNL paper cited by Mr. Fine found avoided distribution costs in a number of case studies for different utilities where DERs were found to offset peak load,

[10] 9/24/21 Final Order, Case Nos. 2020-00349, 2020-00350, at 52-54; *See also* KU/LGE Response to Commission's Fourth Requests for Information, No. 13(c) (Sept. 23, 2025).

deferring the need for system upgrades.[11] But as noted in the Companies' study attached as Exhibit PWW-3 to my testimony: (1) the DER penetration on the Companies' system isn't significant enough at present to meaningfully impact peak load; and (2) distribution circuits on the Companies' system are not operated so close to load ratings such that DERs would make a material impact in deferring capacity upgrades. For these reasons, the potential savings identified in the NBNL paper are simply not realized on LG&E and KU's system.

CONCLUSION

Q. Do you have a recommendation for the Commission?

A. Yes, I recommend that the forecasted expenses for storm restoration and vegetation management be approved as proposed by the Companies and that the Commission approve use of regulatory accounting for these expenses. I further recommend that the Commission approve the proposed NMS-2 export rates.

Q. Does this conclude your testimony?

A. Yes, it does.

[11] Fine Testimony, pp. 11-13, citing Natalie Mims Frick et al., *Locational Value of Distributed Energy Resources, Lawrence Berkeley Nat'l Laboratory*, at 19 (Feb. 2021), https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Peter W. Waldrab**, being duly sworn, deposes and says that he is Vice President, Electric Distribution, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the forgoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Peter W. Waldrab

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of September 2025.

Mary A. Wheeler
Notary Public

Notary Public ID No. KYNP 92214

My Commission Expires:

September 11, 2028