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**

DIRECT TESTIMONY OF
MICHAEL E. HORNUNG
MANAGER, PRICING/TARIFFS
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 30, 2025

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I. INTRODUCTION AND OVERVIEW

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

A. My name is Michael E. Hornung. I am a Manager of Pricing/Tariffs for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") and an employee of LG&E and KU Services Company. My business address is 2701 Eastpoint Parkway, Louisville, Kentucky 40223. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before this Commission a number of times.[1] Most recently, I testified before this Commission in the Companies' proceeding to update their qualifying facility ("QF") and net metering service ("NMS") rates.[2]

Q. What is the purpose of your direct testimony?

A. I will (1) support certain exhibits required by the Commission's regulations; (2) discuss and explain the various tariff changes the Companies propose, including adding a new Extremely High Load Factor standard rate schedule (Rate EHLF) and explaining the Companies' plan for small distributed generation customers after the Companies' current Rider NMS-2 closes to new customers; and (3) update the Commission on the status of grandfathered customers.

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[1] *See, e.g., Application of Kentucky Utilities Company For Approval of Special Contract Between Kentucky Utilities Company and BlueOval SK, LLC*, Case No. 2023-00123, Direct Testimony of Michael E. Hornung (Apr. 14, 2023); *Electronic Investigation of the Proposed Pole Attachment Tariffs of Investor Owned Electric Utilities*, Case No. 2022-00105, Rebuttal Testimony of Michael E. Hornung (July 11, 2022).

[2] *Electronic Tariff Filings of Louisville Gas and Electric Company and Kentucky Utilities Company to Revise Purchase Rates for Small Capacity and Large Capacity Cogeneration and Power Production Qualifying Facilities and Net Metering Service-2 Credit Rates*, Case No. 2023-00404, Rebuttal Testimony of Michael E. Hornung (Apr. 4, 2024).

Q. Are you sponsoring any exhibits to your testimony?

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

Exhibit MEH-1	Cost Support for Rate PSA
Exhibit MEH-2	Cost Support for Rates EVSE and EVSE-R (KU)
Exhibit MEH-3	Cost Support for Rates EVSE and EVSE-R (LG&E)
Exhibit MEH-4	Cost Support for AMI Opt-Out Charges

II. FILING REQUIREMENTS

Q. Are you supporting certain information required by Commission regulation 807 KAR 5:001?

A. Yes, I am sponsoring the following schedules for the corresponding filing requirements for both Companies:

• Proposed Tariff	Section 16(1)(b)(3)	Tab 4
• Proposed Tariff Changes	Section 16(1)(b)(4)	Tab 5
• Narrative description and explanation of all proposed tariff changes	Section 16(8)(l)	Tab 65

III. ELECTRIC RATE DESIGN

A. Electric Rate Design Approach

Q. What is the basic objective of the electric rate design the Companies propose?

A. The Companies' proposed rate design continues to bring both the structure and the charges of the rate design in line with the results of the cost of service studies.

B. Residential Electric Rate Design and Increase

Q. Do the Companies propose to change their Residential Service (Rate RS) rate structure?

A. No. The rate structure will remain the same and consist of a daily Basic Service Charge and a flat volumetric, per-kWh energy charge. The energy charge will continue to be separated into Infrastructure and Variable components in the tariff.

Q. Do the Companies propose to bring the rate components in residential electric rates more in line with their cost of service studies?

A. Yes, although on a gradual basis. The Companies are proposing to increase the daily Basic Service Charge for Rates RS, Residential Time-of-Day Demand Service (Rate RTOD-Demand), Residential Time-of-Day Energy Service (Rate RTOD-Energy), and Volunteer Fire Department Service (Rate VFD) from $0.53 to $0.64 for KU (a 20.8% increase), and from $0.45 to $0.52 for LG&E (a 15.6% increase). The percentage increase for each residential Basic Service Charge is approximately 150% of the total revenue percentage increase proposed for the residential class for each of the Companies (13.6% for KU; 10.1% for LG&E). As presented by Timothy S. Lyons, the electric cost of service studies for KU and LG&E indicate the customer-related cost for the residential class is $0.81 per customer per day. Therefore, the Companies are proposing to increase their residential Basic Service Charges in a direction that will more accurately reflect the actual cost of providing service but will still be less than the full amount of customer-related cost.

C. <u>Support for Late Payment Charges for Residential Customers</u>

Q. In the Companies' 2020 base rate cases, the Commission stated the Companies should file cost support for their late payment charges regardless of whether they

proposed to change them.[3] Are the Companies proposing to change their residential late payment charges, and how are they providing the required support?

A. No, the Companies are not proposing to change their current 3% residential late payment charge. The support for retaining the current residential late payment charge percentage is in the testimony of Mr. Lyons.

IV. EXTREMELY HIGH LOAD FACTOR (STANDARD RATE EHLF)

Q. Why are the Companies' proposing Rate EHLF?

A. The Companies recognize that customers with large demands (more than 100 MVA) and very high load factors (expected average load factor above 85%) have sufficiently different service characteristics and potential financial impacts to the Companies and their other customers to require a separate rate schedule and terms and conditions of service. In particular, because any one or just a few such customers could require the Companies to acquire additional generation resources to supply their needs and the needs of existing customers, increased minimum billing demands, extended contract terms, and enhanced collateral requirements are appropriate for such customers. As I explain below, Rate EHLF addresses all of these items to provide reasonable protections for the Companies and their customers while also providing average embedded cost rate service to all customers.

Q. Please describe and explain the Companies' proposed Rate EHLF.

[3] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, Order at 44 (Ky. PSC June 30, 2021); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350, Order at 47 (Ky. PSC June 30, 2021).

A. As I noted above, Customers with a contract capacity greater than 100 MVA and an average monthly load factor above 85% would take service under Rate EHLF. Rate EHLF is largely the same as the Companies' Rate RTS with a few key changes appropriate to large-load customers with extremely high load factors.

First, because extremely high load factor customers' demands would not change appreciably across various times of day or seasons by definition, Rate EHLF has a single, non-time-differentiated demand charge to recover all demand-related costs of service. This differs from all of the Companies' other large commercial and industrial rate schedules with demand charges, which have separate base, intermediate, and peak demand charges with seasonally differentiated intermediate and peak time period hours. Having a single demand charge ensures these extremely high load factor customers pay their full and fair share of demand-related transmission and generation costs.

Second, Rate EHLF has a much higher minimum billing demand ratchet than the Companies' other large commercial and industrial rate schedules. Rate EHLF requires the monthly billing demand to be the greater of (1) the maximum measured load in the billing period, (2) the highest measured load in the preceding eleven billing periods, or (3) 80% of the maximum contract capacity. In contrast, Rate RTS has the same requirements for just the base demand charge—though only a 50% of contract capacity provision—and minimum billing demands for the intermediate and peak periods of the greater of (1) the maximum measured load in the billing period, (2) 50% of the highest measured load in the preceding eleven billing periods. Thus, Rate EHLF ensures that large, extremely high load factor customers will pay minimum demand charges consistent with what they represent to the Companies they will require.

Third, to ensure the Companies—and their customers—have reasonable assurance that large, extremely high load factor customers will pay their fair share of costs, Rate EHLF requires a minimum initial contract term of 15 years. This makes the Rate EHLF minimum contract term the longest by far of all the Companies' minimum contract terms. It is *15 times longer* than the Rate RTS minimum contract term and three times longer than the Rate FLS minimum contract term—and Rate FLS is available to fluctuating loads up to 200 MVA. In addition, Rate EHLF includes provisions that ensure customers taking service under the rate schedule pay all minimum demand charges and basic service charges for the full 15-year initial term; there are no exceptions for capacity reduction or early termination requests.

Fourth, unlike the standard 2/12 deposit requirements that apply to other commercial and industrial rate schedules, Rate EHLF includes substantial collateral requirements to protect the Companies and their customers. Specifically, each Rate EHLF customer or its guarantor must provide collateral in the form of cash or a letter of credit equal to 24 months of the minimum billed amounts at the largest contract capacity value—twelve times the standard deposit requirement. If the customer or its guarantor has an S&P Credit Rating of at least A and a Moody's Credit Rating of at least A2 with cash and cash equivalents on its audited balance sheet of at least 10 times the collateral requirement, the customer or its guarantor must provide cash or a letter of credit equal to 12 months of the minimum billed amounts at the largest contract capacity value. All collateral is due at the signing of the electric service agreement. If there is an adverse change to the customer's or its guarantor's creditworthiness, the customer or its guarantor must provide the Companies the increased collateral requirement (i.e., the 24 months' value) within three business days after written notice from the Companies. Again, this is a unique requirement for Rate EHLF customers that protects the Companies and all other customers.

Q. Are the rates, terms, and conditions of Rate EHLF both necessary and sufficient to ensure Rate EHLF customers pay their fair share of costs and to protect other customers?

A. Yes. Although all customers who do not receive special rates (e.g., Economic Development Rider customers) or request non-standard generation arrangements (e.g., Green Tariff Option #3 customers) should receive service under rates based on average embedded cost—which Rate EHLF provides—it is also reasonable to require additional financial commitments and assurances from customers who are so consequential to the Companies' system. In that vein, Rate EHLF has: (1) an increased minimum demand charge ratchet (80% of contract capacity); (2) an extended contract term requirement and capacity change and termination provisions that ensure recovery of at least fifteen years of non-fuel revenues based on the original contract capacity requirement; and (3) a collateral posting obligation for at least a full year of non-fuel revenue, which must be posted at the time of service contract signing. To make the effects of these terms more concrete, a 402 MW LG&E Rate EHLF customer meeting the enhanced creditworthiness requirements would need to post collateral of more than $100 million at the time of contract signing. That same customer would have a 15-year minimum demand charge obligation of about $1.1 billion. Again, recognizing the significant financial impacts such large and high load factor customers could have, these enhanced financial commitments and requirements are appropriate for Rate EHLF customers and provide significant protection for the Companies and their customers.

V. OTHER ELECTRIC RATE AND TARIFF CHANGES

A. Small – Medium Business Customers

Q. What changes are the Companies proposing to their General Service Time-of-Day ("GTOD") rates, Rates GTOD-Energy and GTOD-Demand (Sheet Nos. 11 – 11.1 and 12 – 12.1, respectively)?

A. As proposed by the Companies and approved by the Commission in the Companies' 2020 rate cases, the then-new GTOD rate schedules were limited to Rate GS customers participating in the existing Advanced Metering Systems ("AMS") Offering, which was a limited participation smart meter pilot program the Companies provided as part of their DSM-EE program portfolio. Currently, only 41 customers take GTOD service from KU, and only 55 customers take GTOD service from LG&E. Now that the Companies' advanced metering infrastructure ("AMI") deployment is nearly complete and their AMS Offering has been removed from their DSM-EE programs, the Companies are revising their GTOD tariff sheets to make the rates available to up to 500 total customers across both GTOD rates for each Company. This will allow participation in these pilot rates to grow and provide useful data while keeping the cohort of participating customers small enough to be manageable and minimize any potentially adverse revenue impacts.

Q. What changes are the Companies proposing to their Power Service rate, Rate PS (Sheet Nos. 15 – 15.2)?

A. The Companies propose to change their PS demand rates from a non-time-differentiated seasonal demand rate to the same time-of-use, base-intermediate-peak demand rate structure the Companies have long had for their Time-of-Day Secondary, Time-of-Day Primary, and Retail Transmission Service rates (Rates TODS, TODP, and RTS, respectively). With the full deployment of AMI meters, the Companies now have metering for all PS customers that allows for this more granular demand rate structure. This will give customers financial incentives to move demand from on-peak to off-peak periods, which should benefit all customers.

The Companies further propose to change their PS demand rates from a $/kW charge to a $/kVA charge. This change eliminates the power factor adjustment and is a more accurate measurement of the demands customers place on the Companies' system.

Finally, the Companies are revising the Term of Contract provision to clarify that all new Rate PS service will require a one-year contract.

B. <u>Rate Grandfathering for Rates GS and PS</u>

Q. What is rate grandfathering, and how did it arise for the Companies' Rate GS and PS customers?

A. The Companies use the term "rate grandfathering" (or simply "grandfathering") to refer to an exemption allowing customers taking service under a rate schedule to continue doing so even after the availability terms change in a way that would otherwise exclude the grandfathered customers from taking service under that rate schedule. For the Companies, grandfathering for Rates GS and PS arose in the Companies' 2008 base rate cases.

Q. How many customers are currently grandfathered?

A. A total of 1,035 KU and 652 LG&E customers now receiving service under Rate GS were eligible for such service in 2009 only as a result of the grandfather provision. Of this number, approximately 457 KU and 242 LG&E customers are currently eligible for service under Rate GS based upon their current usage patterns without regard to the grandfathering provision.

Approximately 563 KU and 295 LG&E customers currently served under Rate PS were eligible for such service under that rate schedule in 2009 only because of the grandfathering provision. Of this number, approximately 79 KU and 90 LG&E customers meet the availability requirements for service under Rate PS without relying upon the grandfathering provision.

Q. What do the Companies propose in these proceedings concerning grandfathering for Rates GS and PS?

A. Consistent with prior practice, the Companies propose to remove grandfathered status from grandfathered customers that meet the availability requirements of their rate schedules on the date new rates go into effect from these proceedings.

C. <u>Large Business Customers</u>

Q. What changes are the Companies proposing to their Rates TODS, TODP, and RTS (Sheet Nos. 20 – 20.2, 22 – 22.2, and 25 – 25.2, respectively)?

A. The Companies are clarifying the Availability section of these rate schedules by replacing the word "minimum" with "maximum" in the requirement that such customers have "twelve (12) month-average monthly minimum [now "maximum"] loads exceed[ing] 250 kVA." The revision reflects the Companies' intent and actual practice; it will not affect any the availability of these rates schedules for any current customers.

D. Lighting Service and Pole and Structure Attachment Charges

Q. What revisions do the Companies propose to make to Restricted Lighting Service (Rate RLS), Sheet Nos. 36 – 36.3?

A. Rate RLS exists to serve customers who take lighting service using legacy, non-LED lighting fixtures and poles, and it is restricted to such lighting fixtures and poles in service as of July 1, 2021. Spot replacements are not available for these lights. Thus, the number and types of fixtures and poles served under this rate will decline and eventually come to zero as the lights these fixtures and poles support fail. Consistent with that expectation, the Companies have revised Rate RLS to remove the lighting types that no longer serve any customers.

Q. What revisions do the Companies propose to make to Outdoor Sports Lighting Service (currently Rate Pilot OSL), Sheet Nos. 81 – 81.2?

A. The Companies propose to make Outdoor Sports Lighting Service a standard rate rather than a pilot rate. Other than adding two items to the list of Adjustment Clauses that apply to the rate, which affects all rate schedules subject to Adjustment Clauses as I discuss further below, and revising the OSL rates, the Companies are not proposing any other changes to this rate schedule.

Q. What revisions do the Companies propose to make to Traffic Energy Service (Rate TE), Sheet Nos. 38 – 38.1?

A. The Availability section of this rate has always included a non-exhaustive list of traffic control and law enforcement device types served under the rate. For the sake of increased clarity, the Companies propose to revise this provision to explicitly include in this non-exhaustive list a few additional traffic control-related device types served under the rate.

The Companies are also adding text to clarify that customers taking such service shall reimburse them for all installation and removal costs.

Q. What revisions do the Companies propose to make to Pole and Structure Attachment Charges (Rate PSA), Sheet Nos. 40 – 40.32?

A. The Companies propose to bifurcate their current single wireline pole attachment charge into a two-user wireline pole attachment charge and a three-user wireline pole attachment charge.

Q. Why are the Companies proposing these revisions?

A. There are several reasons. First, and most importantly, the current rate of $7.25 does not reflect the Companies' cost of service. The $7.25 attachment rate has been in place since 2016. In the past decade, the Companies' pole costs have increased substantially. For frame of reference, the Handy Whitman Index, South Atlantic Region, for FERC Account 364 (the account which records investment in distribution poles) in January 2016 was 495; in January 2024, it was 673, which is an increase of 36%. All the while, the Companies' pole attachment rate remained static, which means the Companies have been under-recovering their costs from Attachment Customers. The new rates proposed by the Companies reflect our current cost of service for providing pole attachments. Second, the proposed bifurcation of rates will more closely align with the Commission's order in Administrative Case No. 251, which establishes separate methodologies for two-user and three-user poles. The single rate that has been part of our tariffs since at least 2010 was, as best we can tell, the result of a settlement and stipulation that used a blended rate based on then-existing cost experience. We have not endeavored to update the rate since then.

Q. What are the two-user and three-user rates the Companies are proposing?

A. We are proposing $10.13 for two-user poles and $10.46 for three-user poles.

Q. Why is the rate for a three-user pole higher than the rate for a two-user pole?

A. Although the allocation of costs per attachment is lower under the three-user formula (7.59% vs. 12.24%), the Companies' cost basis is higher for the three-user poles. The three-user rate formula uses the weighted average cost of 40-foot and 45-foot poles, whereas the two-user rate formula uses the weighted average cost of 35-foot and 40-foot poles. In recent years, most of the new poles set—either as replacements of existing poles or new pole lines—are 45-foot poles. This is particularly true with respect to poles replaced to accommodate Attachment Customers. These 45-foot poles are not only more expensive than 35-foot poles, but the average 45-foot pole in the Companies' system is also newer (i.e., less depreciated) than the average 35-foot pole. Because the three-user formula uses a cost basis of poles that are taller and newer than the cost basis for the two-user formula, it more than offsets the different in the space allocation.

Q. Are you sponsoring any exhibits in connection with the Companies' requested revisions to Pole and Structure Attachment Charges (Rate PSA), Sheet Nos. 40 – 40.32?

A. Yes. I am sponsoring Exhibit MEH-1, which presents the calculations and cost data supporting the proposed two-user and three-user rates.

E. <u>Electric Vehicle Rates</u>

Q. How are the Companies addressing the Commission's directive from the Companies' 2020 rate cases to file cost-based electric vehicle ("EV") charging tariff provisions that incentivize off-peak charging?[4]

A. The Companies' current and proposed tariffs now contain multiple EV charging options for residential and commercial customers. These include the RTOD and GTOD rate schedules, which incentivize usage during off-peak hours, including EV charging. Also, the Companies' current Demand-Side Management and Energy Efficiency Program Plan, which the Commission approved in November 2023, now includes an Optimized Charging program (Sheet No. 86.8).[5] All Rate RS customers may participate in the program (as well as residential customers who take service under Rate GS for a detached garage), and they receive incentives to do so. The program allows the Companies to issue signals to qualifying EVs and qualifying EV supply equipment to affect the timing and level of charging for EVs within parameters set by participants.

I address other EV-related tariff provisions below.

Therefore, the Companies have fully addressed the Commission's EV-related directive from the Companies' 2020 rate cases.

Q. What revisions do the Companies propose to make to Electric Vehicle Supply Equipment (Rate EVSE and Rider EVSE-R), Sheet Nos. 41 – 41.2 and 75 – 75.2, respectively?

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[4] Case No. 2020-00349, Order at 16 (Ky. PSC June 30, 2021); Case No. 2020-00349, Order at 19 (Ky. PSC June 30, 2021).

[5] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order (Ky. PSC Nov. 6, 2023).

A. The Companies are adding a new charger type to EVSE and EVSE-R, “Economy Networked Charger.” The Companies are also revising the Rate EVSE Energy Consumption provision for non-metered charging stations from 5,004 kWh to 8,203 kWh for KU and from 5,004 kWh to 5,728 kWh for LG&E to more accurately reflect the amount of energy consumption associated with each individual Company’s chargers for Fuel Adjustment Clause purposes. I provide support for the Companies’ EVSE and EVSE-R rates in Exhibits MEH-2 (KU) and MEH-3 (LG&E) to my testimony.

Q. What revisions do the Companies propose to make to Electric Vehicle Charging Service - Level 2 (Rate EVC-L2) and Electric Vehicle Fast Charging Service (Rate EVC-FAST), Sheet Nos. 42 – 42.1 and 43 – 43.1, respectively?

A. The Companies propose to combine the two rate schedules into a single Electric Vehicle Charging Service standard rate schedule (Rate EVC). This has the effect of causing current Rate EVC-L2 to be substantively identical to Rate EVC-FAST, moving away from its current time-based rate structure (charges per time connected to the charger) to a flat, market-based per-kWh charge (plus applicable taxes, including electric vehicle power excise taxes under KRS 138.477, and franchise fees).

The Companies further propose to revise the liability provisions of these rate schedules to be consistent with the broader liability-related revisions I discuss below.

Q. How are the Companies proposing to address the revenue requirements of their EV charging stations in these proceedings?

A. In Case No. 2015-00355, the Commission authorized the Companies to install up to ten Level 2 EV charging stations each,[6] which the Companies committed would not result in increased charges to customers.[7] The Companies have honored that commitment in prior rate cases by imputing revenues sufficient to satisfy the revenue requirements of the Level 2 charging stations.[8] Those Level 2 chargers, which have a ten-year book depreciation life, will be fully depreciated in the forecasted test year, so it is no longer necessary to impute revenues for them to ensure they do not create costs for other customers.

The Companies have not previously addressed revenue requirements for Level 3 EV fast chargers, none of the costs of which were included in the forecasted test years in the Companies' 2020 base rate cases.[9] The Companies have included the revenue requirements of those chargers in their revenue requirements in these proceedings. This is reasonable because all customers are able to use these chargers, and their costs remain minimal.

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[6] *Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Install and Operate Electric Charging Stations in Their Certified Territories, For Approval of an Electric Vehicle Supply Equipment Rider, an Electric Vehicle Supply Equipment Rate, and an Electric Vehicle Charging Rate, Approval of a Depreciation Rate for Electric Vehicle Charging Stations, and for a Deviation From the Requirements of Certain Commission Regulations*, Case No. 2015-00355, Order (Ky. PSC Apr. 11, 2016).

[7] Case No. 2015-00355, Application at 7 (Nov. 13, 2015) ("Each Company will install in its certified territory no more than ten charging stations to provide service under Rate EVC. The total capital outlay involved with such installations is not expected to exceed $500,000 and will neither materially affect the financial condition of either Company nor result in increased charges to their customers."); Case No. 2015-00355, Companies' Response to PSC 2-9 (Feb. 5, 2016) ("The limit on the number of charging stations offered under the EVC tariff is designed to limit the Companies' financial commitment and to ensure that the Companies keep their commitment as set forth at page 7 of the Joint Application that 'the capital outlay involved with such installations is not expected to exceed $500,000 and will neither materially affect the financial condition of either Company nor result in increased charges to their customers.'")

[8] Case No. 2020-00349 and Case No. 2020-00350, Direct Testimony of W. Steven Seelye at 64-65 (Nov. 25, 2020).

[9] *Id.* at 75 ("As mentioned earlier, there are no costs related to the DC Fast Charging in test-year revenue requirements. Because test year revenue requirements do not include costs related to the DC Fast Charging Service, such an adjustment is neither necessary nor possible. The revenue requirement treatment of future investments in DC Fast Charging Stations will be addressed in subsequent rate proceedings.").

F. Special Charges

Q. What revisions do the Companies propose to make to Special Charges, Sheet Nos. 45 – 45.2?

A. The Companies are revising their AMI Opt Out Charges to include a provision requiring customers who refuse to make adequate provision for an AMI meter to pay opt-out charges. This provision results from the Companies' practical experience in deploying AMI meters, in which they have encountered situations in which the existing analog meter for a customer is mounted on the customer's property, typically a customer-owned pole, that has become unsafe. In some such situations, the customer has refused to opt out of AMI installation while also refusing to repair or replace the unsafe pole, placing the Companies and their contractors in an untenable situation. Thus, this provision ensures that customers unwilling to provide a safe location for an AMI meter are treated as opting out of the AMI deployment and must accordingly pay opt-out charges. I provide support for the Companies' AMI Opt-Out charges in Exhibit MEH-4 to my testimony.

G. Qualifying Facility Riders and Net Metering Service

Q. What revisions do the Companies propose to make to Small Capacity Cogeneration and Small Power Production Qualifying Facilities (Rider SQF) and Large Capacity Cogeneration and Large Power Production Qualifying Facilities (Rider LQF), Sheet Nos. 55 – 55.3 and 56 – 56.3, respectively?

A. The Companies are revising energy and capacity rates under Riders SQF and LQF to accord with the avoided energy and generation capacity costs supported by Charles R. Schram.

The Companies are further revising the Availability section of Riders SQF and LQF to clarify that power purchase agreements, and therefore, capacity payments, are available to customers only under buy-all, sell-all arrangements, not to behind-the-meter qualifying facilities in which customers have first call on their facilities' capacity and energy.

The Companies further propose to revise the liability provisions of these rate schedules to be consistent with the broader liability-related revisions I discuss below.

Q. What revisions do the Companies propose to Net Metering Service-2 (Rider NMS-2), Sheet No. 58?

A. The Companies are revising their NMS-2 rates to account for updated avoided costs as discussed in the testimony of Mr. Schram, Elizabeth J. McFarland, and Peter W. Waldrab. The revised rates and their components are below:

Avoided Cost Type	KU ($/kWh)	LG&E ($/kWh)
Energy	0.03859	0.03786
Generation Capacity	-0-	-0-
Carbon	-0-	-0-
Ancillary Services	-0-	-0-
Environmental Compliance	-0-	-0-
Distribution Capacity	-0-	-0-
Transmission Capacity	-0-	-0-
Jobs Benefits	-0-	-0-
Total	**0.03859**	**0.03786**

The Companies are not proposing an NMS-2 rate component related to jobs benefits because such benefits are outside the Commission's jurisdiction.[10] Notably, the

[10] *EnviroPower, LLC v. Public Service Commission of Kentucky*, 2007 WL 289328 at *4 (Ky. App. 2007) (not to be published) ("First, there is the statutory limitation under KRS 278.040(2) that the person seeking intervention must have an interest in the 'rates' or 'service' of a utility, since those are the only two subjects under the jurisdiction of the PSC."); *The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Order at 4 (Ky. PSC July 8, 2011) ("[I]ssues of environmental

Commission recently approved net metering rates for Duke Energy Kentucky that did not include a jobs benefit component, which Duke argued should be zero for the same reason.[11]

The Companies are also adding text to the Availability section to state that, consistent with KRS 278.466(1), each of the Companies will cease offering service under Rider NMS-2 to any new customer-generator after (1) the cumulative generating capacity of NMS-1 and NMS-2 customer-generators reaches a combined 1% of single-hour peak load during a calendar year and (2) the Companies receive Commission approval to cease offering such service. This addition is purely to provide customers notice of the anticipated closing of the rider to new customers; it is not required under KRS 278.466(1).

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externalities, such as air and water pollution from generating electricity and mining fuel to supply the generating plants, are all issues beyond the scope of the Commission's jurisdiction."); *The 2008 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2008-00148, Order at 5-6 (PSC Ky. July 18, 2008) ("Notably absent from the Commission's jurisdiction are environmental concerns, which are the responsibility of other agencies within Kentucky state government."); *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Order at 28-29 (Oct. 5, 2018) (emphasis added; internal citation to KRS 278.040(2)):

> KRS Chapter 278 creates the Commission as a statutory administrative agency empowered with "exclusive jurisdiction over the regulation of rates and service of utilities." *The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service. Lacking jurisdiction over these non-energy factors, the Commission has no authority to require a utility to include such factors in benefit-cost analyses of DSM programs.* As LG&E/KU correctly note, it does not follow from their citing in 2014 of the potential avoidance of environmental compliance costs in rates in support of the construction of a 10 MW solar facility that the Commission has jurisdiction in a DSM case to require an analysis of non-energy criteria such as environmental and health factors that have no impact on rates.

But see, e.g., Case Nos. 2020-00349 and 2020-00350, Order at 57-58 (Ky. PSC Sept. 24, 2021).

[11] *Electronic Application of Duke Energy Kentucky, Inc. for an Adjustment to Rider NM Rates and for Tariff Approval*, Case No. 2023-00413, Order at 13 and 43-44 (Ky. PSC Oct. 11, 2024), *rehearing denied* Case No. 2023-00413, Order at 9 and 12 (Ky. PSC Nov. 20, 2024).

Q. Under what rate would new customer-generators take service after Rider NMS-2 closes?

A. New customer-generators who would have qualified for Rider NMS-2 prior to its closing would be eligible to receive compensation according to the terms of the Companies' Rider SQF. Existing Rider NMS-2 customers would continue to take service under Rider NMS-2.

H. Intermittent Loads Rider

Q. What revisions do the Companies propose to make to Intermittent Loads (Rider IL), Sheet Nos. 65 – 65.1?

A. Upon further review, it became apparent that the rate provisions of Rider IL had no effect, and the remaining provisions would be more appropriate as Terms and Conditions of service. Therefore, the Companies have removed the superfluous rate provisions and moved the balance of Rider IL to a new Intermittent Loads provision in the Customer Responsibilities section of the Terms and Conditions, Sheet No. 97.4.

I. Solar Share Program

Q. What revisions do the Companies propose to make to their Solar Share Program Rider (Rider SSP), Sheet Nos. 72 – 72.3?

A. The Companies propose a number of revisions to expand the Solar Share Program's availability and utilization.

First, the Companies are revising the Availability section to open the Solar Share Program to Rate RTS customers.

Second, the Companies are removing the restriction from the One-Time Solar Capacity Charge that limited its use to Solar Share Facilities that had not begun construction. This allows customers new to the Solar Share Program to pay the One-

Time Solar Capacity Charge rather than the Monthly Solar Capacity Charge and begin to enjoy the benefits of the Solar Share Program right away.

Third, the Companies are removing the cap on the amount of Solar Share Facilities capacity a customer may subscribe.

Fourth, the Companies are reducing the number of days a customer has after terminating service to transfer the customer's Solar Share Program subscription from 60 days to 30 days. The Companies proactively contact and seek to work with customers who terminate their service regarding transferring their Solar Share Program subscriptions. The Companies have found that customers who desire to transfer their Solar Share Program subscriptions do so within 30 days; the remaining former customers typically do not respond to the Companies' contacts after 30 days, resulting in unnecessarily restricting the Companies' ability to offer the abandoned subscriptions to other customers. This revision will therefore help advance transferring these subscriptions to other customers more quickly.

Altogether, these changes should help advance the purposes of the Solar Share Program and accelerate the pace of building new Solar Share Facilities.

J. <u>Demand-Side Management Cost Recovery Mechanism</u>

Q. What revisions do the Companies propose to make to their Demand-Side Management Cost Recovery Mechanism (Adjustment Clause DSM), Sheet Nos. 86 - 86.10?

A. The Companies are making minor clarifying revisions to Adjustment Clause DSM, as well as revisions to expand certain programs' availability as noted in the testimony of Shannon L. Montgomery. Regarding the latter, the Companies are making the following changes:

- Making non-residential programs available to the new Rate EHLF;
- Making the Whole-Building Multi-Family program available to Rates PS, TODS, and TODP; and
- Adding grandfathered Rate GS customers to the list of qualifying rate schedules for the Non-Residential Demand Response program.

Finally, the Companies are removing the requirement that customers who purchase new smart thermostats through the Online Transactional Marketplace be automatically enrolled in the Bring Your Own Device program for smart thermostats. As Ms. Montgomery explains, the Companies anticipate that making this optional rather than mandatory could help increase smart thermostat purchases through the Online Transactional Marketplace.

K. <u>Terms and Conditions</u>

Q. Please describe the changes the Companies propose in the liability provisions of the Customer Responsibilities and Company Responsibilities sections of the Terms and Conditions (Sheet Nos. 97.2 and 98.1).

A. The Companies are proposing to clarify their liability limitations generally. In all circumstances other than liability resulting from service interruptions, the Companies propose to uniformly limit their liability to where the serving Company's gross negligence or willful misconduct is the sole and proximate cause of injury or damage. The Companies propose to retain and narrow their existing liability resulting from service interruptions to where the serving Company's willful misconduct is the sole and proximate cause of loss, injury, or damage. The broader exemption from liability for service interruptions is reasonable and necessary to protect the Companies and their customers from potentially ruinous liability.

Importantly, any expansion of the Companies' potential liability will result in increased costs for all customers in the form of necessarily higher liability insurance premiums and other risk mitigation measures the Companies would have to implement. The Companies believe their proposed liability provisions appropriately balance risk and minimize overall costs.

Q. Please explain the changes the Companies propose to the Permits section of the Terms and Conditions at Sheet No. 97.3.

A. The Companies propose to revise this section to clarify its compliance with 807 KAR 5:006 Section 6(3). The current text has been in the Companies tariffs unchanged since well before the Commission adopted 807 KAR 5:006 Section 6(3). Although the Companies have always acted in compliance with the revised regulation, in comprehensively reviewing their tariffs for these cases, they observed that this provision of their tariffs would benefit from revisions to clarify its compliance with the current regulation.

Q. Please explain the addition of the Incidental or Occasional Utility-Related Services provision to the Terms and Conditions at Sheet No. 98.

A. This provision clarifies that the Companies may recover their costs from customers for performing incidental or occasional utility-related services, such as customer-requested line relocations, burying a line underground, moving a guy wire out of a customer's yard, and attaching or removing devices to or from utility facilities and the like.

Q. Please describe the changes the Companies propose to the Billing section of the Terms and Conditions (Sheet No. 101).

A. As explained in Ms. Montgomery's testimony, the Companies are proposing to move all customers for whom the Companies have an email address on file to paperless billing. The Companies anticipate this will result in reduced costs and improved customer satisfaction. As the proposed tariff provision reflects, customers may opt out of paperless billing by contacting the Companies to request paper bills by mail.

The Companies are proposing the same change to the billing section LG&E's gas tariff at Sheet No. 101.

Q. Please describe the changes the Companies propose to the Deposits section of the Terms and Conditions (Sheet Nos. 102 – 102.6).

A. The Companies have revised and expanded the text of the Deposits section to more fully and explicitly articulate their Deposits policy as actually implemented. Because there are so many different customer situations that arise, it is not practicable to set out in the Companies' tariffs every possible deposit scenario, but this expansion helps increase transparency for customers and should help enhance the overall customer experience. In other words, although the proposed revisions add several pages to the Deposits section, they do not represent or reflect any substantive change to the Companies' deposit policy as implemented; rather, they simply make it more transparent.

Q. Please describe the Pre-Pay Program section the Companies are proposing to add to the Terms and Conditions (Sheet No. 104).

A. The Commission's June 30, 2021 Orders in the Companies' 2020 rate cases directed the Companies to develop and implement prepay programs, which the Commission required the Companies to propose in their next base rate cases.[12] Subject to certain restrictions, the Companies' proposed Pre-Pay Program allows residential customers with AMI meters to move from traditional post-paid service to a deposit-free prepaid service with as little as $30 prepaid to start. That service will allow payment by all existing payment channels and by any low-income assistance agency, and participating customers will receive and be able to customize low-balance alerts to help them ensure they have adequate prepaid balances for their own needs. Other terms and conditions are set out in the proposed tariff provision. Overall, the Companies believe this is a valuable option for customers that satisfies the Commission's 2020 rate case Orders on this topic.

Q. Please describe the Rules for Retail Electric Service Studies and Related Implementation Costs section the Companies are proposing to add to the Terms and Conditions (Sheet No. 108).

A. The Companies are adding the Rules for Retail Electric Service Studies and Related Implementation Costs section to clarify and codify the Companies' practices and cost responsibility concerning customers or prospective customers who request service resulting in Transmission Service Requests ("TSRs") and eventual transmission system-related additions or upgrades. This provision requires any customer or prospective customer who asks the Companies to investigate possible service that requires the Companies to issue a TSR to the Companies' Independent Transmission

[12] Case No. 2020-00349, Order at 16 (Ky. PSC June 30, 2021); Case No. 2020-00350, Order at 18 (Ky. PSC June 30, 2021).

Organization to pay all costs of the TSR application and studies. It also requires prospective customers to enter into engineering, procurement, and construction ("EPC") agreements to cover all transmission-related costs the Companies incur related to any studied service, and it requires existing customers to do the same if the estimated construction costs exceed $10 million. These provisions protect the Companies and their customers from exposure to costs related to potentially speculative service.

Q. Please describe the changes the Companies propose to the Net Metering Service Interconnection Guidelines section of the Terms and Conditions (Sheet Nos. 109 – 109.5).

A. Broadly, the Companies are proposing to update their Net Metering Service Interconnection Guidelines to reflect technological and safety standard developments since the Commission first approved uniform guidelines for such interconnections more than 16 years ago.[13] These changes are not intended to be and are not substantive.

Q. Have the Companies made any other changes to their electric tariffs?

A. Yes. The Companies have made a number of small edits to clarify certain issues, harmonize the KU and LG&E electric tariffs, and make clean-up edits throughout their tariffs.

VI. GAS RATE DESIGN

A. Gas Rate Design Approach

Q. What is the basic objective of the gas rate design LG&E proposes?

[13] *Interconnection and Net Metering Guidelines for Retail Electric Suppliers and Qualifying Customer-Owned Generators*, Admin. Case No. 2008-00169, Order (Ky. PSC Jan. 8, 2009).

A. As with the Companies' proposed electric rate design, LG&E's proposed gas rate design continues to bring both the structure and the charges of the rate design in line with the results of the cost of service studies.

B. Residential Gas Rate Design and Increase

Q. Does LG&E propose to bring the rate components in residential gas rates more in line with the cost of service study?

A. Yes. LG&E is proposing a daily Basic Service Charge of $0.81 for Rates RGS and VFD, which is a 24.6% increase from the current daily Basic Service Charge of $0.65. As Mr. Lyons discusses further in his testimony, the cost of service study indicates that the customer-related cost for the residential class is $1.04 per day. As with the Companies' electric residential Basic Service Charges, LG&E's proposed percentage increase for its gas residential Basic Service Charge is approximately 150% of the total revenue percentage increase proposed for the residential class (14.9%). Therefore, LG&E is proposing to increase the Basic Service Charge in a direction that will more accurately reflect the actual cost of providing service but will still be less than the full amount of customer-related cost.

C. Demand-Side Management Cost Recovery Mechanism

Q. Please explain the proposed revisions to the Demand-Side Management Cost Recovery Mechanism (Adjustment Clause DSM) at Sheet No. 86.5.

A. LG&E is adding text concerning Demand Response Programs and Connected Solutions to align the electric and gas tariffs appropriately and clarify that gas customers are eligible to participate in the Online Transactional Marketplace.

VII. OTHER GAS RATE AND TARIFF MATTERS

Q. Please explain the proposed text additions to Firm Commercial Gas Service (Rate CGS) and Firm Industrial Gas Service (Rate IGS), Sheet Nos. 10 – 10.2 and 15 – 15.2, respectively.

A. LG&E proposes to add text to the CGS and IGS rate schedules to give LG&E the right to inspect a customer's gas-fired generator installation to ensure compliance with the requirement that all such generators that can consume gas at a rate of 2,000 cubic feet per hour or more are served under the Distributed Generation Gas Service rate (Rate DGGS).

LG&E is also making a conforming addition to Distributed Generation Gas Service (Rate DGGS) at Sheet No. 35.2.

Q. Please explain the proposed revisions to the Standard Facilities Charge provision of the Standard Facility Contribution Rider (Rider SFC) at Sheet No. 64.

A. In addition to the changes to Rider SFC addressed in the testimony of Tom C. Reith, LG&E proposes to revise the interest rate component of the Rider SFC Standard Facilities Charge. Currently, the interest rate component of the Rider SFC Standard Facilities Charge is the five-year Treasury constant maturity rate published in the latest Federal Reserve Statistical Release H-15 (as of the day immediately preceding the date when the agreement under Rider SFC is executed with the customer) plus 100 basis points. LG&E proposes to add 50 basis points (a total of 150 basis points added to the Treasury rate) to account for the customer credit risk LG&E bears under the terms of Rider SFC.

Q. Please explain the proposed revisions to the Creditworthiness provisions of Local Gas Delivery Service (Rate LGDS) at Sheet No. 36.13 and the Standard Facility Contribution Rider (Rider SFC) at Sheet No. 64.1.

A. LG&E proposes to revise the Creditworthiness provisions of Rate LGDS and Rider SFC to remove cash as a means of providing credit support to the Company because letters of credit or such other financial instruments are typically less expensive for customers and create less administrative burden for LG&E. LG&E further proposes to add text requiring a customer to replenish within two business days any posted credit support upon which LG&E must draw to satisfy the customer's obligation to the Company.

To the extent these revisions require deviations from the deposit requirements of 807 KAR 5:006 Sec. 8, LG&E hereby requests such deviations under 807 KAR 5:006 Sec. 28.

Q. Please explain the proposed revisions to the Special Terms and Conditions sections of Pooling Service – Rider TS-2 at Sheet No. 59.7 and Pooling Service – Rate FT at Sheet No. 61.2.

A. LG&E proposes similar revisions to the Special Terms and Conditions sections of Pooling Service – Rider TS-2 at Sheet No. 59.7 and Pooling Service – Rate FT at Sheet No. 61.2 as it does to the Creditworthiness provision of Rate LGDS described above and for the same reasons. To the extent these revisions require deviations from the deposit requirements of 807 KAR 5:006 Sec. 8, LG&E hereby requests such deviations under 807 KAR 5:006 Sec. 28.

Q. Please explain the proposed Force Majeure addition to the General Terms and Conditions at Sheet No. 96.1.

A. "Force majeure" is a term repeatedly used but not defined in the current LG&E gas tariff. The proposed text remedies that omission with a standard force majeure provision.

Q. Please explain the changes LG&E proposes to the Permits section of the Terms and Conditions at Sheet No. 97.2.

A. For the same reasons I described above concerning the Companies' proposed revisions to the Permits section of their electric tariffs at Sheet No. 97.3, LG&E proposes to revise this section of its gas tariff to clarify its compliance with 807 KAR 5:006 Section 6(3).

Q. Please explain the addition of the Incidental or Occasional Utility-Related Services provision to LG&E's Terms and Conditions at Sheet No. 98.

A. For the same reasons I described above concerning the Companies' proposed addition of the Incidental or Occasional Utility-Related Services provision to the Terms and Conditions at Sheet No. 98 of their electric tariffs, LG&E proposes to add this provision to its gas tariff.

Q. Please describe the changes LG&E proposes to the Billing section of the Terms and Conditions (Sheet No. 101).

A. As explained above and in Ms. Montgomery's testimony, LG&E is proposing to move all customers for whom it has an email address on file to paperless billing. As the proposed tariff provision reflects, customers may opt out of paperless billing by contacting LG&E to request paper bills by mail.

Q. Please describe the changes LG&E proposes to the Deposits section of LG&E's Terms and Conditions (Sheet Nos. 102 – 102.4).

A. For the same reasons I described above concerning the Companies' proposed revisions to the Deposits sections of their electric tariffs, LG&E proposes to make conforming revisions to its gas tariff.

Q. Please describe the Pre-Pay Program section LG&E proposes to add to its Terms and Conditions (Sheet No. 104).

A. For the same reasons I described above concerning the Companies' proposed addition of the Pre-Pay Program to their Terms and Conditions at Sheet No. 104 of their electric tariffs, LG&E proposes to add this provision to its gas tariff.

Q. Has LG&E made any other changes to its gas tariff?

A. Yes. In addition to tariff revisions discussed by other witnesses, LG&E has made a number of small edits to clarify certain issues and make clean-up edits throughout its gas tariff.

VIII. CONCLUSION

Q. What are your conclusions and recommendations?

A. Based on the evidence provided above and in the Companies' applications in these proceedings, I conclude the rates and proposed changes to the Companies' tariffs described herein are reasonable and will aid the Companies in continuing to provide safe, reliable, and economical service to their customers. Therefore, I recommend the Commission approve the Companies' proposed rates and changes to their tariffs described herein.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Michael E. Hornung**, being duly sworn, deposes and says that he is Manager of Pricing/Tariffs for LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Michael E. Hornung

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2025.

Caroline J. Davison
Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON COMM EXPIRES 01/22/2027 NOTARY PUBLIC ID # KYNP63286 STATE AT LARGE, KENTUCKY

APPENDIX A

Michael E. Hornung
Manager, Pricing/Tariffs
LG&E and KU Services Company
2701 Eastpoint Parkway
Louisville, Kentucky 40223

Professional Experience

Louisville Gas and Electric Company and Kentucky Utilities Company

Manager, Pricing & Tariffs	Jan. 2018 – Present
Acting Director, Revenue Integrity	Jan. 2017 – July 2017
Manager, Billing Integrity	Jan. 2016 – Dec. 2016
	Jul. 2017 – Dec. 2017
Manager, Energy Efficiency Planning & Development	Aug. 2008 – Dec. 2015
Senior Rate & Regulatory Analyst	Aug. 2006 – Aug. 2008
Senior Market Policy Analyst	Feb. 2000 – Aug. 2006
Senior Financial Analyst	
Risk Management/Trading Controls	June 1999 – Feb. 2000
Senior Accountant at LG&E Energy Marketing	1997 – 1999
Venture Accountant at LG&E Power, Inc.	1996 – 1997
General Labor, LG&E Construction	Summer 1988 & 1989

Professional Memberships

Electric Edison Institute (EEI)	Jan. 2018 - Present
Southeastern Electric Exchange (SEE)	Jan. 2018 - Present

Education

Bachelor of Science in Business Administration - Accounting
University of Louisville, August 1992

Strategic Business Integration: Generation & Energy Marketing, August 2009

Kentucky Utilities Company and Louisvillle Gas & Electric Company
Calculation Of Attachment Charges for Underground Conduit
Based on 12 Months Ended Dec 2025

Pole Description			**Total**
Gross Plant		$	101,398,507
Remove Appurtenances			15%
Gross Plant less Appurtenances		$	86,188,731
Accumulated Depreciation			(43,526,602)
Remove Appurtenances			15%
Accumulated Depreciation less Appurtenances		$	(36,997,612)
Net Plant		$	49,191,120
Accumulated Deferred Income Taxes		$	9,888,070
Cash Working Capital			227,755
Common Plant			1,664,836
Net Cost Rate Base		$	60,971,782
Rate of Return			8.11%
Return		$	4,946,438
Income Taxes	24.85%	$	1,166,763
Property Taxes		$	871,552
Depreciation Expenses		$	1,787,238
Maintenance of UG Lines		$	630,046
A&G Expense Allocation to UG Lines			677,556
Revenue Requirement		$	10,079,594
Quantity			4,123,765
Average Installed Cost		$	2.44
Space Usage Factor			0.50
Underground Conduit Attachment Rate		**$**	**1.22**

Kentucky Utilities Company and Louisvillle Gas & Electric Company
Cost Support for Attachment Charges for Wireline Pole Attachments
Based on 12 Months Ended December 31, 2026

Pole Description		**35'**	**40'**	**45'**	**Total**
Gross Plant		$ 52,036,461	$ 191,098,649	$ 200,352,686	$ 443,487,797
Remove Appurtenances		15%	15%	15%	
Gross Plant less Appurtenances		$ 44,230,992	$ 162,433,852	$ 170,299,783	$ 376,964,627
Accumulated Depreciation		(18,708,471)	(68,704,971)	(72,032,040)	(159,445,482)
Remove Appurtenances		15%	15%	15%	
Accumulated Depreciation less Appurtenances		$ (15,902,200)	$ (58,399,226)	$ (61,227,234)	$ (135,528,660)
Net Plant		$ 28,328,791	$ 104,034,626	$ 109,072,549	$ 241,435,967
Accumulated Deferred Income Taxes		$ (6,970,804)	$ (25,599,575)	$ (26,839,246)	$ (59,409,625)
Cash Working Capital		206,198	757,240	793,910	1,757,347
Common Plant		953,770	3,502,625	3,672,242	8,128,637
Net Cost Rate Base		$ 22,517,955	$ 82,694,917	$ 86,699,455	$ 191,912,326
Rate of Return		8.11%	8.11%	8.11%	
Return		$ 1,826,807	$ 6,708,764	$ 7,033,638	$ 15,569,209
Income Taxes	24.95%	$ 433,282	$ 1,591,184	$ 1,668,238	$ 3,692,704
Property Taxes		$ 411,839	$ 1,512,439	$ 1,585,679	$ 3,509,958
Depreciation Expenses		$ 1,282,985	$ 4,711,634	$ 4,939,797	$ 10,934,416
Maintenance of Poles		$ 476,343	$ 1,749,321	$ 1,834,033	$ 4,059,697
Tree Trimming of Poles		799,227	2,935,082	3,077,214	$ 6,811,523
A&G Expense Allocation to Poles		412,583	1,515,169	1,588,542	$ 3,516,294
Revenue Requirement		$ 5,643,067	$ 20,723,592	$ 21,727,141	$ 48,093,800
Quantity		112,699	205,964	102,069	420,732
Average Installed Cost		$ 50.07	$ 100.62	$ 212.87	$ 114.31
(1) Amount of Usable Space Occupied (in feet)		1.00	1.00	1.00	1.00
(2) Total Usable Space 3 Users (per Order 251)		13.17	13.17	13.17	13.17
(3) Total Usable Space 2 Users (per Order 251)		8.17	8.17	8.17	8.17
Space Usage Factor ((1) / (2))		0.0759	0.0759	0.0759	0.0759
Space Usage Factor ((1) / (3))		0.1224	0.1224	0.1224	0.1224
Pole Attachment Rate		$ 3.80	$ 7.64	$ 16.16	**$ 8.68**
Two-User Pole Rate					**$ 10.13**
Three-User Pole Rate					**$ 10.46**
Weighted Pole Rate					**$ 10.29**
					41.97%
Current					7.2500
					19.72%
Wireless Facility				Current	$ 36.25
				Proposed	**$ 51.46**

Kentucky Utilities Company
Derivation of Rates

		Option A - Single	Option A - Dual	EVSE / EVSE-R Non-Networked - Single	Option B - Single	Option B - Dual
Estimated Investment per Unit		$ 4,981.00	$ 6,995.00	$1,022.22	$ 4,181.12	$ 4,960.01
Fixed Charges @	21.55%	$ 1,073.19	$ 1,507.12	$ 322.47	$ 900.85	$ 1,068.67
O&M (Scheduled/Trouble)		$ 310.20	$ 620.39	$ 124.36	$ 260.38	$ 439.91
Annual Network Cost		$ 345.00	$ 690.00	$ -	$ 200.00	$ 400.00
		$ 1,728.39	$ 2,817.51	$ 446.83	$ 1,361.24	$ 1,908.58
Monthly Rate for Equipment Only		$ 144.03	$ 234.79	$ 37.24	$ 113.44	$ 159.05
EVC Rate per Hour for Equipment Only		-	-	-	-	-
Distribution Energy per kWh per year (Calculated with GS Rate)	$ 0.13957	$ 573.30	$ 1,146.60	$ 573.30	$ 573.30	$ 1,146.60
Distribution Energy per kWh per month		$ 47.78	$ 95.55	$ 47.78	$ 47.78	$ 95.55
Distribution Energy per kWh per hour		-	-	-	-	-
Basic Service Charge		$ -	$ -	$ -	$ -	$ -
Fuel Adjustment Clause		$ -	$ -	$ -	$ -	$ -
Environmental Surcharge (Level 2)		$ -	$ -	$ -	$ -	$ -
Retired Asset Recovery Adjustment Clause		$ -	$ -	$ -	$ -	$ -
Renewable PPA Adjustment Clause		$ -	$ -	$ -	$ -	$ -
EVSE Monthly Rate for Equipment, Energy & Factors		**$ 191.81**	**$ 330.34**	**$ 85.01**	**$ 161.21**	**$ 254.60**
EVC Fee per Hour for Equipment, Energy & Factors						
EVSE-R Monthly Rate for Equipment Only		**$ 144.03**	**$ 234.79**	**$ 37.24**	**$ 113.44**	**$ 159.05**

Louisville Gas and Electric Company
Derivation of Rates

		Option A - Single	Option A - Dual	EVSE / EVSE-R Non-Networked - Single	Option B - Single	Option B - Dual
Estimated Investment per Unit		$ 4,981.00	$ 6,995.00	$1,022.22	$ 4,181.12	$ 4,960.01
Fixed Charges @	21.74%	$ 1,083.10	$ 1,521.04	$ 324.50	$ 909.17	$ 1,078.54
O&M (Scheduled/Trouble)		$ 391.32	$ 782.64	$ 124.36	$ 328.48	$ 554.95
Annual Network Cost		$ 345.00	$ 690.00	$ -	$ 200.00	$ 400.00
		$ 1,819.42	$ 2,993.68	$ 448.86	$ 1,437.65	$ 2,033.49
Monthly Rate for Equipment Only		$ 151.62	$ 249.47	$ 37.41	$ 119.80	$ 169.46
EVC Rate per Hour for Equipment Only		-	-	-	-	-
Distribution Energy per kWh per year (Calculated with GS Rate)	$ 0.13471	$ 472.19	$ 944.38	$ 472.19	$ 472.19	$ 944.38
Distribution Energy per kWh per month		$ 39.35	$ 78.70	$ 39.35	$ 39.35	$ 78.70
Distribution Energy per kWh per hour		-	-	-	-	-
Basic Service Charge		$ -	$ -	$ -	$ -	$ -
Fuel Adjustment Clause		$ -	$ -	$ -	$ -	$ -
Environmental Surcharge (Level 2)		$ -	$ -	$ -	$ -	$ -
Retired Asset Recovery Adjustment Clause		$ -	$ -	$ -	$ -	$ -
Renewable PPA Adjustment Clause		$ -	$ -	$ -	$ -	$ -
EVSE Monthly Rate for Equipment, Energy & Factors		**$ 190.97**	**$ 328.17**	**$ 76.75**	**$ 159.15**	**$ 248.16**
EVC Fee per Hour for Equipment, Energy & Factors						
EVSE-R Monthly Rate for Equipment Only		**$ 151.62**	**$ 249.47**	**$ 37.41**	**$ 119.80**	**$ 169.46**

LG&E -- Electric AMI Opt-Out Charge

	One-Time Fee		
4.	Meter Readers	$	57,819
5.	Field Services	$	111,066
6.	Enrollment	$	10,148
7.	One-Time Fee	$	179,033
8.	One-Time Fee costs divided by All Opt-Out Contracts	$	80.07
	One-Time and Recurring Capital Costs		
	15 Year Life		
9.	Mesh Network	$	15,318
10.	Enrollment, Billing and Reporting	$	132,959
11.	One-Time and Recurring Capital Costs to be recovered	$	148,277
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$	66.31
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer[1]	$	1.16
	Annual Recurring Costs		
14.	Meter Readers	$	488,610
15.	Field Services	$	6,856
16.	Mesh Network	$	329
17.	Annual Recovery of on-going Costs	$	495,795
18.	Monthly Recovery of Recurring Costs per Contract	$	18.48
19.	Total Monthly Fee (13 + 18)	$	19.64

LG&E -- Gas AMI Opt-Out Charge

	One-Time Fee		
4.	Meter Readers	$	43,261
5.	Field Services	$	90,530
6.	Enrollment	$	7,593
7.	One-Time Fee	$	141,384
8.	One-Time Fee costs divided by All Opt-Out Contracts	$	84.51
	One-Time and Recurring Capital Costs		
	15 Year Life		
9.	Mesh Network	$	11,459
10.	Enrollment, Billing and Reporting	$	99,466
11.	One-Time and Recurring Capital Costs to be recovered	$	110,925
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$	66.30
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer[1]	$	1.17
	Annual Recurring Costs		
14.	Meter Readers	$	146,229
15.	Field Services	$	5,146
16.	Mesh Network	$	246
17.	Annual Recovery of on-going Costs	$	151,622
18.	Monthly Recovery of Recurring Costs per Contract	$	7.55
19.	Total Monthly Fee (13 + 18)	$	8.72

Kentucky Utilities -- AMI Opt Out Charges

	One-Time Fee		
4.	Meter Readers	$	79,429
5.	Field Services	$	109,806
6.	Enrollment	$	12,637
7.	One-Time Fee	$	201,872
8.	One-Time Fee costs divided by All Opt-Out Contracts	$	73.73
	One-Time and Recurring Capital Costs		
	15 Year Life		
9.	Mesh Network	$	18,759
10.	Enrollment, Billing and Reporting	$	162,830
11.	One-Time and Recurring Capital Costs to be recovered	$	181,590
12.	One-Time and Recurring Capital Costs divided by All Opt-Out Contracts	$	66.32
13.	Monthly Levelized Revenue Requirement Recovery of One-Time and Recurring Capital per Customer[1]	$	1.16
	Annual Recurring Costs		
14.	Meter Readers	$	749,026
15.	Field Services	$	10,266
16.	Mesh Network	$	403
17.	Annual Recovery of on-going Costs	$	759,696
18.	Monthly Recovery of Recurring Costs per Contract	$	23.12
19.	Total Monthly Fee (13 + 18)	$	24.29