COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A Certificate Of Public Convenience And Necessity Authorizing The Deployment Of Advanced Metering Infrastructure; (2) Request For Accounting Treatment; And (3) All Other Necessary Waivers, Approvals, And Relief	))))))	Case No. 2024-00344

DIRECT TESTIMONY OF

LERAH M. KAHN

ON BEHALF OF KENTUCKY POWER COMPANY

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EXHIBIT LMK-1	Results for the Company's cost-benefit analysis
EXHIBIT LMK-2	Comparison of the alternatives for both customer impact and benefits

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I. INTRODUCTION

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

A. My name is Lerah M. Kahn, and my position is Manager of Regulatory Services, Kentucky Power Company ("Kentucky Power" or the "Company"). My business address is 1645 Winchester Avenue, Ashland, Kentucky 41101.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.

A. In 2009, I earned a Bachelor of Arts degree in History from the University of Guelph in Guelph, Ontario, Canada. Additionally, in 2010 I received a Paralegal diploma from Algonquin Careers Academy in Mississauga, Ontario, Canada.

From 2013 through 2018 I worked at Sogefi Group Inc., a global supplier for the automotive industry, as a material planner and accounting specialist. I accepted the position of Regulatory Consultant with Kentucky Power Company in July 2018, and I was promoted to my current position as Manager of Regulatory Services in February 2023.

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

A. As Manager of Regulatory Services, I am responsible for the supervision and direction of Kentucky Power's Regulatory Services Department, which has responsibility for all rate and regulatory matters involving the Company.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before this Commission in Case No. 2019-00389 (application for approval of the Company's 2019 Environmental Compliance Plan ("ECP")), Case No. 2020-00133 (Commission's examination of the Company's Environmental Surcharge mechanism for the two-year billing period ending June 30, 2019), Case No. 2020-00174 (the Company's previous base rate case), Case No. 2021-00004 (application for approval of the Company's 2021 ECP), Case No. 2022-00387 (application for a special contract), Case No. 2023-00159 (the Company's most recent base rate case), Case No. 2023-00372 (Commission's examination of the Company's Environmental Surcharge mechanism for the four-year billing period ending June 30, 2023), and Case No. 2024-00136 (Commission's examination of the Company's Fuel Adjustment Clause mechanism for the six-month period ending April 30, 2023).

III. PURPOSE OF TESTIMONY

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

A. My testimony covers the following topics:

- A high-level overview of the Company's proposal to replace its existing, obsolete metering infrastructure with Advanced Metering Infrastructure ("AMI");
- Demonstrate that the requested certificate of public convenience and necessity is appropriate including the need for replacing the Company's existing, obsolete metering infrastructure and the process by which Kentucky Power evaluated options to do so;
- A request for accounting treatment to track and defer for future recovery of the costs associated with replacing the Company's metering infrastructure; and
- A request for deviation from the testing requirements of 807 KAR 5:006 Section 14(3); 807 KAR 5:006 Section 26(4)(e) and (5)(a)(2); and 807 KAR 5:041, Sections 15(3) and 16.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

- Exhibit LMK-1: results for the Company's cost-benefit analysis ("CBA"); and
- Exhibit LMK-2: comparison of the alternatives for both customer impact and benefits.

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

A. Yes.

Q. PLEASE PROVIDE AN OVERVIEW OF THE OTHER DIRECT TESTIMONY BEING SUBMITTED IN THIS CASE.

A. Kentucky Power is also filing direct testimony from the following witnesses:

- Stephen D. Blankenship – Mr. Blankenship, Region Support Manager for Kentucky Power, describes the Company's current Automatic Meter Reading ("AMR") infrastructure and its need to be replaced, the proposed deployment schedule, and benefits AMI will provide for electric distribution.
- Stevi N. Cobern – Ms. Cobern, Regulatory Consultant Principal for Kentucky Power, describes the benefits AMI will provide to customers and customer service along with the Company's AMI engagement and education plan.

IV. <u>THE COMPANY'S AMI PROPOSAL</u>

Q. WHAT IS AMI?

A. AMI is a metering infrastructure system that utilizes two-way communications that enables a meter to send information to the utility and the utility to communicate instructions to the meter. The Company's current meter reading technology, AMR, is only capable of communicating in one direction – from the meter to a receiver. Company Witness Blankenship discusses AMI technology further in his direct testimony.

Q. WHAT ARE THE MAJOR BENEFITS ASSOCIATED WITH AMI?

A. First and foremost, proactive AMI deployment represents the most reasonable, cost-effective method to serve our customers. Additionally, AMI will provide customers with the ability to monitor and regulate their usage throughout the billing period, an expanded customer platform, and enhanced customer service experience. These customer benefits are discussed further by Company Witness Cobern.

AMI also provides the Company with significantly more data regarding customer usage than AMR is capable of (35,000-meter readings or data points each year vs. 12 currently). Access to this data will allow the Company to evaluate customer usage and determine whether any current tariff offerings (such as time-of-day rates) need to be refined or if new rate schedules can be supported.

Finally, AMI meters will provide the Company excellent visibility into its distribution system. As a result, the Company will be better positioned to prevent and handle outages, validate restoration, manage voltage, and determine asset loading. This results in a better and more efficient distribution system. These operational benefits are discussed further by Company Witness Blankenship.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED DEPLOYMENT PLAN.

A. The Company's proposal is to proactively install AMI over four years beginning in 2026 by focusing on economies of scale (*i.e.*, starting in densely populated areas first and then moving to rural areas). Additionally, the Company will take into consideration both circuit and billing cycle information for its deployment plan. Full deployment is expected by the end of 2029. Company Witness Blankenship discusses the deployment plan in more detail in his direct testimony.

Q. IF THE COMPANY DOES NOT PLAN TO BEGIN INSTALLATION OF AMI UNTIL 2026, WHY IS IT SEEKING APPROVAL NOW?

A. The timing of the Company's application considers the significant lead-time and resources necessary to deploy AMI. Figure LMK-1 below summarizes the anticipated timeline for the Company's chosen vendor:

Figure LMK-1

Milestone	Due Date(s)	
Application Filed	8-Nov-24	
Final Order	1-Jul-25	
Order Meters	Q3 2025	9-12-mos from order to receipt
IT Infrastructure-Billing	Q1-Q2 2026	12-mos
IT Infrastructure-Backhaul	Q1-Q2 2026	9-12-mos
2026 Deployment (Ashland)	Q2-Q4 2026	.5-year
2027 Deployment (Pikeville -75%)	2027	1-year
2027 Deployment (Hazard)	2028	1-year
2029 Deployment (Pikeville-Remaining 25%)	2029	1-year

V. KENTUCKY CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") REQUIREMENTS

Q. DOES THE COMPANY'S AMI PROPOSAL MEET KENTUCKY CPCN REQUIREMENTS?

A. While I am not a lawyer, it is my understanding that the Company's application fully satisfies Kentucky's CPCN requirements and Commission precedent for a demonstration of need and that there is no wasteful duplication. The testimony supporting the application demonstrates that the proactive deployment of AMI is the lowest-cost option to customers, coupled with the best customer experience from reliability to better control over energy consumption.

Q. HAS THE COMMISSION GIVEN ANY ADDITIONAL GUIDANCE AS TO WHAT IT EXPECTS THE COMPANY TO PROVIDE AS EVIDENCE REGARDING THE NEED FOR AMI DEPLOYMENT?

A. Yes, in the Company's 2020 base rate case (2020-00174), the Commission found that the Company, in any future CPCN application for AMI deployment, must demonstrate its existing AMR system is obsolete, that Kentucky Power evaluated multiple proposals filed in response to a request for proposal ("RFP"), and that an analysis was completed to show the AMI project is the lowest-cost alternative.[1] The Company's proposal considers and satisfies each of these elements.

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[1] Order, *In the Matter of: Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval Of A Certificate Of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief*, Case No. 2020-00174, at 80 (Jan. 13, 2021).

Additionally, the Commission stated that the Company should demonstrate that the systems under considerations are effective for its service territory.[2] Company Witness Blankenship details how the selected vendor (Landis+Gyr) will best serve the Company's service territory and customers.

Lastly, the Commission previously addressed the appropriateness of replacing obsolete meter technology in several cases and has approved the replacement with AMI meters of existing technology that was or soon would be obsolete.[3] The Commission further elaborated upon its reasoning in those cases, explaining that its approvals of AMI were based upon those utilities providing substantial evidence that: (1) "the existing meters were either no longer available or supported or in the near future would no longer be available or supported;" (2) the utilities "could not provide reliable, adequate service with the existing meters;" and (3) "the proposed AMI system was the least-cost alternative."[4] For further discussion on items (1) and (2) please see the direct testimony of Company Witness Blankenship while item (3) is detailed within my testimony.

Q. HAS THE COMPANY RECEIVED FEEDBACK FROM EXTERNAL STAKEHOLDERS AROUND AN AMI DEPLOYMENT?

A. Yes. The Company received feedback from external stakeholders on its 2020 AMI proposal that were critical of the Company not having selected a vendor at the time, the lack of a CBA, and the proposal to recover costs through a rider mechanism. Each

[2] *Id*.
[3] Order, *In the Matter of: Electronic Joint Application Of Louisville Gas And Electric Company And Kentucky Utilities Company For A Certificate Of Public Convenience And Necessity For Full Deployment Of Advanced Metering Systems*, Case No. 2018-00005, at 9 (Aug. 30, 2018).
[4] *Id*. at 9-10.

of these concerns have been taken into consideration as part of this filing. Company Witness Blankenship discusses the process for selecting the Company's chosen vendor (Landis+Gyr) while my testimony provides and discusses the CBA prepared on a net-present value basis and the Company's proposal to defer costs until a subsequent base rate proceeding.

a. Need

Q. WHY DOES THE COMPANY NEED TO REPLACE ITS EXISTING AMR METERING INFRASTRUCTURE?

A. The Company's need to replace its AMR system is driven by two key factors:

<u>Proactive AMI Deployment provides benefits to customers and reduces the cost to serve customers</u>.

As shown in Figure LMK-2 below and on Exhibit LMK-1, the proactive deployment of AMI results in net savings to customers of $39.3 million (relative to the Company's current costs). Using the Total Resource Cost ratio ("TRC") which evaluates program benefits in relation to costs, the score is 2.78. Overall, these results mean that the benefits exceed the costs, and that this proposed capital investment is forecasted to reduce costs and ultimately customer bills over the 20-year forecast period compared to what they would be otherwise. The benefits to customers of AMI are even clearer when comparing Alternative 1 (AMI Proactive Deployment) to the SCM+ alternative (Alternative 3 and 4 below) – either of which would be more representative of the going forward "status quo". Exhibit LMK-2 provides a summary comparison for customer impact and benefits achieved under each alternative. These alternatives are discussed in detail later in my testimony.

Figure LMK-2

	1 **AMI Proactive Deployment**	2 **AMI Reactive Deployment**	3 **SCM+ Proactive Deployment**	4 **SCM+ Reactive Deployment**
Costs	$22.1	$23.8	$57.0	$52.4
Quantifiable Savings	$61.4	$52.5	$0.0	$0.0
Customer Impact ***(Costs less Savings)***	$(39.3)	$(28.7)	$57.0	$52.4
TRC Test (Savings divided by Costs)	2.78	2.21	0	0

Costs, Savings and Customer Impact are provided on a net present value basis and in millions.

AMR technology is obsolete.

The Company started installing AMR metering in 2005. At that time, Kentucky Power, like many other utilities, was transitioning away from electro-mechanical meters. It took approximately two years to complete the installation of AMR meters across the Company's service territory. AMR meters have a 15-year life expectancy, or design life. Unsurprisingly, the Company's existing AMR meters are experiencing a high rate of failure as they approach the end of their design life. Failed meters result in AMR not effectuating its main purposes: Company personnel can no longer drive by to receive a reading and/or see the information on the meters interface.

Additionally, there are no longer any vendors manufacturing the Company's current AMR meters. Only one vendor in the United States refurbishes the type of AMR meters used by the Company and it is a small portion of their sales. It is reasonable to assume this segment of their business will eventually cease as the rate of AMI penetration continues to overtake the market.

Continuing with AMR metering given that these meters are at or past their design life and experiencing increased failure rates as a result, coupled with a single choice in vendor for refurbished meters is impractical at best. Should the lone vendor refurbishing AMR meters go out of business or stop refurbishing AMR meters, Kentucky Power would be forced to continue operating with most meters in the field at or exceeding their design life and without a readily available source of replacement meters or parts. Similarly, should the Company experience a catastrophic event that were to forcibly retire a large portion of its existing AMR meters, there would be no supplier or existing stock available to rebound from such an event and prevent the Company from meeting its obligation to provide safe and reliable service to its customers.

b. Wasteful Duplication

Q. DOES THE COMPANY'S AMI PROPOSAL RESULT IN WASTEFUL DUPLICATION?

A. No. AMR meters have a 15-year life expectancy and as discussed above the Company began installing its current AMR metering system 19 years ago in 2005. This means that at the start of AMI implementation (2026) most of the retired meters will be 20 years old (5 years past their design life) and those being retired by the end of AMI implementation (2029) will be 24 years (9 years past their design life).

Q. WHAT IS THE CURRENT NET BOOK VALUE OF THE COMPANY'S AMR METERS?

A. As of August 2024, the Company's net book value for AMR was $13.8 million. The expected net book value for AMR upon installation of AMI (estimate of June 2026) using currently approved depreciation rates is $11.7 million.

Q. IF THE MAJORITY OF THE COMPANY'S CURRENT METERS ARE PAST THEIR EXPECTED LIFE, WHY DOES THERE REMAIN AN UNDEPRECIATED BALANCE?

A. The Company's AMR meters are being depreciated in the Distribution Plant function which has an annual depreciation rate of 3.52%. The current depreciation rate of 3.52% is being used for all Distribution Plant, including meters. This rate has not been updated since the depreciation study filed in Case No. 91-066 and was calculated using plant in service balances at December 31, 1989, resulting in the undepreciated balance that is expected to be on the books at the time AMI installation begins.

Q. WAS THE UNDEPRECIATED VALUE OF THE COMPANY'S EXISTING METER INFRASTRUCTURE TAKEN INTO CONSIDERATION WHEN EVALUATING THE LOWEST-COST OPTION?

A. Yes, the undepreciated value of AMR meters was incorporated into the CBA (see the "Remaining AMR NBV" line on Exhibit LMK-1). Even accounting for the undepreciated value of the AMR meters, the analysis demonstrates that the substantial and quantifiable savings associated with proactive AMI deployment will produce net savings to customers over 20 years.

c. Meter Replacement Evaluation

Q. HOW DID KENTUCKY POWER EVALUATE TECHNOLOGIES FOR REPLACING ITS EXISTING, OBSOLETE METERING INFRASTRUCTURE?

A. Consistent with the Commission's 2020 base case order the Company issued an RFP to AMI metering infrastructure vendors on February 14, 2024. Additionally, on February 28, 2024, the Company issued a Request for Quote ("RFQ") for AMR meters with the newer SCM+ technology to the only company that provides such meters. Company Witness Blankenship discusses the RFP and RFQ process in detail, SCM+ technology and its impracticability, and how the cost and technological benefits resulted in the Company selecting Landis+Gyr as the AMI provider. Following the RFP/RFQ, the Company performed the CBA described below. From this analysis, the Company determined that Alternative 1, a proactive replacement of the Company's existing, obsolete metering infrastructure with AMI, represents the most reasonable, lowest-cost alternative.

Q. PLEASE SUMMARIZE THE ALTERNATIVES CONSIDERED.

A. The Company considered four alternatives within its CBA. These alternatives are:

<u>Alternative 1: Proactive AMI Deployment</u>

In Alternative 1, the Company will proactively replace its obsolete AMR metering infrastructure with Landis+Gyr AMI meters over a period of four years beginning in 2026. A proactive approach allows the Company to strategically target (by circuit and billing cycle) deployment of the new meters. This alternative represents the lowest cost option and produces net savings to customers over 20 years due to the significant quantifiable savings coupled with the lower costs associated with a proactive deployment.

<u>Alternative 2: Reactive AMI Deployment</u>

In Alternative 2, the Company will reactively replace existing, obsolete AMR meters with Landis+Gyr AMI meters when the existing AMR meters fail. The Company anticipates that such reactive deployment of AMI would occur over eight years beginning in 2026. The extended deployment period results in losing the benefits associated with the economies of scale and strategic deployment utilized in Alternative 1. Specifically, the quantifiable savings are eroded by the reactive approach – which would require the Company to maintain two different metering systems for an undetermined period and sporadic deployment as meters fail at unknown times and locations throughout the Company's vast geographical service territory (approximately 3,787 square miles). Accordingly, Alternative 2 falls behind Alternative 1 and is the second lowest cost option.

<u>Alternative 3: SCM+ Proactive Replacement</u>

In Alternative 3, the Company will proactively replace its existing, obsolete AMR metering infrastructure with AMR meters utilizing the SCM+ platform. Under Alternative 3, the Company would deploy the SCM+ meters over two years beginning in 2026. Although Alternative 2 utilizes the more efficient proactive deployment process discussed under Alternative 1, it represents the highest cost option to customers due to the higher remaining net book value on retired AMR meters and the SCM+ options do not include the quantifiable savings associated with AMI such as reduced labor costs. Furthermore, none of the qualitative benefits associated with AMI are realized and the risk associated with utilizing a system provided by a sole vendor, that is unable to guarantee service for any period of time, would be imprudent.

Alternative 4: SCM+ Reactive Replacement

In Alternative 4, the Company would reactively replace existing, obsolete AMR meters with AMR meters utilizing the SCM+ platform as existing AMR meters fail. The Company anticipates that the reactive deployment of AMR meters utilizing the SCM+ platform would occur over eight years beginning in 2026. Alternative 4 represents the second highest cost to customers. The costs of Alternative 4 are similar to Alternative 3 except there is greater depreciation (reduction to the net book value) of the Company's existing meters as they will remain in the field longer (albeit at increased failure rates).

All alternatives were benchmarked against the Company's current costs. As shown in Figure LMK-2, the results of the CBA clearly demonstrate that the most reasonable and prudent alternative is Alternative 1, Proactive AMI. Exhibit LMK-1 provides a further breakdown on how these values were calculated. Please also see Exhibit LMK-2 for a comparison of the alternatives on customer impact and benefits achieved under each.

d. Cost-Benefit Analysis ("CBA")

Q. PLEASE DESCRIBE THE FINANCIAL MODEL THE COMPANY UTILIZED IN ITS CBA.

A. The financial model utilized Microsoft Excel and quantifies program costs and benefits over a 20-year forecast. Two cost-benefit measures were considered:

- Net Present Value ("NPV") – which represents the difference between cost recovery (for the return of and return on new capital investments) and lower expenses that are passed through to customers; and
- Total Resource Cost ("TRC") – which evaluates the program benefits in relation to the costs.

Costs were separated between capital costs and O&M expenses. For capital costs, the Company forecasted customer impacts utilizing net capital costs and a simple rate base calculation as shown on Exhibit LMK-1. For O&M expenses, reduced expenses were included as simple passthrough savings from the customer perspective. Then, bringing together net capital costs and net O&M expenses, the total cost of each Alternative was developed. The analysis showed that the total costs, on a NPV basis, for Alternative 1 was the lowest.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COSTS THAT THE COMPANY INCLUDED IN THE CBA.

A. The costs have been broken down in the CBA analysis by the following categories and are based on the RFP response provided by Landis+Gyr and the RFQ response provided for AMR with SCM+:

- Capital Costs – total capital costs expected to be incurred and includes meters, communications infrastructure, IT, and program management costs.
- Ongoing O&M Expenses – begin once upfront deployment activities are completed and extend throughout the 20-year business case period. These costs include routine meter maintenance, annual IT fees, and ongoing support of analytics and data warehousing.

Q. CAN YOU PLEASE SUMMARIZE THE COSTS DETERMINED IN THE COST BENEFIT ANALYSIS?

A. As presented on Exhibit LMK-1, Alternative 1, Proactive AMI Deployment, is the lowest cost alternative on a net present value basis. The net capital costs and ongoing O&M expenses for Alternative 1 is $22.1M over the 20-year look compared to $23.8M for Alternative 2, $57.0M for Alternative 3, and $52.4M for Alternative 4.

Q. PLEASE PROVIDE AN OVERVIEW OF THE BENEFITS THAT ARE INCLUDED IN THE CBA.

A. Benefits include those that are utility-driven cost reductions and impacts that are a result of customer behavior changes and are broken down into the following categories:

- Avoided O&M Expenses – related to eliminated manual meter reads and disconnect/reconnect trips, as well as efficiencies within outage management and billing estimation.
- Revenue Protection Benefits – includes reductions in tamper and theft and consumption on inactive meters.
- Customer Benefits – quantified customer benefits (energy savings) and enhanced customer engagement tools.
- Avoided Capital Cost – accounts for avoided costs associated with maintaining the status quo (running existing AMR system to failure and upgrading to SCM+ on a reactive basis) – including meters and IT system upgrades – that would otherwise be required if AMI was not implemented.

Q. CAN YOU PLEASE EXPLAIN FURTHER WHAT IS INCLUDED IN THE AVOIDED O&M EXPENSES CATEGORY?

A. As a result of a full AMI deployment, the Company expects to see reductions in expenses related to avoided trips for disconnects and reconnects due to remote metering, reduced outage restoration costs, and a reduction in costs associated with meter reading. Company Witness Blankenship provides more detail with respect to the Company's plans to achieve the operational benefits associated with AMI technology.

Q. WHAT ARE THE COMPONENTS OF THE REVENUE PROTECTION BENEFITS INCLUDED IN THIS CBA?

A. The revenue protection benefits are comprised of AMI related benefits associated with reducing tamper and theft and consumption on inactive meters.

The Company will be able to leverage AMI to improve meter tampering and energy theft detection efforts. As part of a broader category called unaccounted for energy, tamper and theft are considered to be a significant industry issue.[5] AMI technology is expected to provide foundational capabilities for addressing this issue. When coupled with analytics software and increased analysis and field service efforts, detecting anomalous patterns of energy usage can be done in a more real-time, comprehensive, and effective manner.

Lastly, AMI technology will provide the Company with the ability to access consumption data in near real-time and leverage remote disconnect capabilities to reduce or eliminate consumption on inactive meters.

Q. WHAT IS INCLUDED IN THE CUSTOMER BENEFITS CATEGORY?

A. Customer benefits are realized when customers participate in engagement tools (such as Home Energy Management discussed in detail by Company Witness Cobern) that

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[5] See pp. 93 of https://www.energy.gov/oe/articles/ami-system-security-requirements-v101-1

are enabled by AMI and as a result, change their electric consumption behavior. For each of these engagement tools, the Company developed customer participation and impact forecasts.

Q. PLEASE EXPLAIN WHAT IS INCLUDED IN THE AVOIDED CAPITAL COSTS BENEFIT CATEGORY.

A. The avoided capital costs benefit captures the avoided costs associated with continuing to operate and replace the legacy AMR system with SCM+. As discussed by Company Witness Blankenship this approach would eventually require AMI investment but on an undetermined schedule due to the sole vendor's inability to provide guarantee of continuing to support SCM+ for any period of time.

Q. ARE THERE ANY OTHER AMI BENEFITS THAT THE COMPANY HAS NOT QUANTIFIED IN ITS CBA?

A. Yes. While the Company's CBA includes a wide range of quantified benefits, there are significant non-quantifiable benefits. Examples include improvements in employee safety, emergency response, customer communication and engagement, call center efficiency, distribution planning and operations, and improvement in customer capabilities. Additionally, the move to AMI will allow the Company to propose new customer billing options such as prepay.

Q. CAN YOU PLEASE SUMMARIZE THE BENEFITS DETERMINED IN THE COST BENEFIT ANALYSIS?

A. As presented on Exhibit LMK-1, the 20-year cumulative benefits for Alternative 1, Proactive AMI Deployment, totals $61.4M compared to $52.5M for Alternative 2.

Alternative 3 and Alternative 4, because they rely on one-way AMR technology, will provide no benefits beyond the Company's current metering technology.

Q. BASED ON THE RESULTS OF THE CBA WHAT CONCLUSION HAS THE COMPANY REACHED IN REGARD TO REPLACING ITS EXISTING, OBSOLETE METERING INFRASTRUCTURE?

A. After considering the CBA results, the Company concluded that Alternative 1, Proactive AMI Deployment, represents the solution that is reasonable, financially justified, and valuable for both the Company and its customers. The successful execution of AMI, as proposed in this application and supported by the CBA, will allow the Company to join its peer utilities in modernizing the grid and improving the customer experience.

VI. <u>COST RECOVERY</u>

Q. HOW WILL THE COMPANY'S AMI INVESTMENT BE FUNDED?

A. Kentucky Power anticipates funding the cost of the proposal through its operating cash flow and other internally generated funds.

Q. WILL THE COST OF THE PROJECT MATERIALLY AFFECT THE COMPANY'S FINANCIAL CONDITION?

A. No, it will not. Kentucky Power's assets, net of regulatory assets and deferred charges, as of September 30, 2024, totaled $2,384,182,669. The cost of the Company's AMI deployment thus represents an increase of approximately 1.73% in those assets. The deployment will not require the issuance of debt and will not affect the completion of any other current capital project.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF AMI DEPLOYMENT?

A. The Company is proposing to defer the costs of AMI deployment until the costs can be included in its rate base in a subsequent base rate proceeding. Doing so ensures that the corresponding quantifiable savings will also be considered within the Company's test year. However, the Company is requesting deferral authority of certain costs as part of this proceeding. This regulatory asset would correspond to the implementation period for AMI and be comprised of costs associated with the AMI project implementation, including depreciation expense and a pre-tax WACC return on AMI rate base, incremental property tax expense and incremental O&M expense. Consistent with the FERC Uniform System of Accounts, the Company plans to recover the remaining net book value of electric meters replaced and retired to Account 108 as part of this project through future depreciation rates.

VII. WAIVERS/DEVIATIONS

Q. IS THE COMPANY REQUESTING ANY WAIVERS NECESSARY FOR AMI DEPLOYMENT?

A. Yes, the Company is requesting a waiver for the following:

807 KAR 5:006 Sections 14(3)

807 KAR 5:006 Section 14(3) requires inspection of meter and service connections before providing new service to ensure no prior or fraudulent use is attributed to the new customer. AMI metering will provide the Company with information and alarms (including for tampering) that would prevent this scenario from occurring.

<u>807 KAR 5:006 Section 26(4)(e) and 26(5)(a)(2)</u>

807 KAR 5:006 requires the inspection of meters every two years. AMI metering will provide insight into the condition of every meter daily. Accordingly, the proposed deviation will ensure that the intent of these regulations is being met while allowing the deviation will provide for further cost-savings (beyond what is captured in the Company's CBA).

<u>807 KAR 5:041, Sections 15(3) and 16</u>

807 KAR 5:041, Sections 15(3) and 16 require that single-phase electric meters must be tested every 8 years or in accordance with a Commission approved sample-meter test plan. Because the Company proposes to replace all of its existing non-AMI single-phase meters within four-years, continued testing during the period would be unnecessary. The Company will resume testing its meters once the AMI deployment is complete.

Section 15(3) also requires the Company to test its metering equipment when it is removed from service. Because the Company proposes to dispose of the existing infrastructure as they are removed, there would be little-to-no benefits to continue to test the removed meters.

VIII. <u>FUTURE CONSIDERATIONS</u>

Q. DOES THE COMPANY ANTICIPATE REQUESTING FUTURE CHANGES TO ITS TARIFF BOOK DUE TO AMI IMPLEMENTATION?

A. Yes, the Company anticipates that future tariff changes will be necessary, or enabled by, the implementation of AMI.

First, the Company recognizes that its miscellaneous charges will need to be addressed to ensure proper consideration of cost-causation. Generally, customers with AMI meters will not cause a field personnel trip to reconnect or disconnect service. However, the Company's deployment of AMI is anticipated to start in Q2 of 2026, accordingly such a request to modify the miscellaneous charges will occur closer to deployment. Secondly, AMI could allow for future approval of a prepay option, which would provide customers greater control over the frequency and timing of their payments. Lastly, the Company expects that the vast amount of data available through AMI will enable it to refine its current time-of-use rates or propose new offerings. However, the Company will first need to have sufficient data to analyze and/or identify usage patterns that would support such requests. It is important to note that these benefits were not captured within the CBA and only increase the value of AMI to customers.

IX. CONCLUSION

Q. IS THE COMPANY'S PROPOSAL REASONABLE AND PRUDENT?

A. Yes. Above all else, the Company's proposal is the lowest cost option for the Company to replace its aging and obsolete metering infrastructure. The benefits that accompany AMI are unattainable elsewise and include better reliability, enhanced outage detection and restoration, enhanced customer service, and near-real time usage insight to effectuate change.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Alternative 1: Proactive AMI Deployment

$ Millions, except when indicated otherwise

LT Debt	52.6%
Common Equity	47.4%
Cost of LT Debt	4.9%
Return on Equity	9.8%
Income Tax (federal & state)	25.7%
Pre-tax WACC	6.83%

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Program capital costs	12.124	11.515	12.110	5.368	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided capital costs	(6.954)	(4.038)	(4.405)	(4.772)	(5.139)	(5.506)	(5.873)	(3.304)	-	-	-	-	-	-	-	-	-	-	-	-
Net capital expenditures	5.171	7.477	7.705	0.596	(5.139)	(5.506)	(5.873)	(3.304)	-	-	-	-	-	-	-	-	-	-	-	-
Amort for recovery	0.199	0.607	1.032	1.248	1.078	0.599	0.083	(0.252)	(0.383)	(0.389)	(0.389)	(0.389)	(0.389)	(0.389)	(0.389)	(0.394)	(0.533)	(0.804)	(0.907)	(0.702)
ADIT	(0.308)	(0.091)	(0.232)	(0.207)	(0.015)	0.170	0.304	0.369	0.290	0.161	0.068	0.044	0.085	0.104	0.052	(0.039)	(0.171)	(0.318)	(0.372)	(0.320)
Rate Base	4.664	11.443	17.885	17.026	10.794	4.858	(0.794)	(3.477)	(2.803)	(2.253)	(1.796)	(1.362)	(0.889)	(0.396)	0.045	0.400	0.762	1.248	1.782	2.164
Net Income	0.215	0.529	0.826	0.787	0.499	0.224	(0.037)	(0.161)	(0.129)	(0.104)	(0.083)	(0.063)	(0.041)	(0.018)	0.002	0.018	0.035	0.058	0.082	0.100
Taxes	0.075	0.183	0.286	0.273	0.173	0.078	(0.013)	(0.056)	(0.045)	(0.036)	(0.029)	(0.022)	(0.014)	(0.006)	0.001	0.006	0.012	0.020	0.029	0.035
EBT	0.290	0.712	1.113	1.059	0.671	0.302	(0.049)	(0.216)	(0.174)	(0.140)	(0.112)	(0.085)	(0.055)	(0.025)	0.003	0.025	0.047	0.078	0.111	0.135
Interest	0.121	0.296	0.462	0.440	0.279	0.126	(0.021)	(0.090)	(0.072)	(0.058)	(0.046)	(0.035)	(0.023)	(0.010)	0.001	0.010	0.020	0.032	0.046	0.056
EBIT	0.411	1.008	1.575	1.499	0.950	0.428	(0.070)	(0.306)	(0.247)	(0.198)	(0.158)	(0.120)	(0.078)	(0.035)	0.004	0.035	0.067	0.110	0.157	0.191
Depreciation	0.199	0.607	1.032	1.248	1.078	0.599	0.083	(0.252)	(0.383)	(0.389)	(0.389)	(0.389)	(0.389)	(0.389)	(0.389)	(0.394)	(0.533)	(0.804)	(0.907)	(0.702)
Remaining AMR NBV	4.061	2.803	2.699	1.090	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	4.670	4.417	5.306	3.837	2.028	1.027	0.013	(0.558)	(0.630)	(0.588)	(0.547)	(0.509)	(0.468)	(0.424)	(0.385)	(0.359)	(0.466)	(0.694)	(0.750)	(0.511)
New O&M expenses	0.549	0.405	0.833	0.629	0.613	0.626	0.639	0.653	0.668	0.683	0.699	0.716	0.734	0.753	0.772	0.793	0.815	0.837	0.861	0.886
O&M expense savings	(1.193)	(1.876)	(3.031)	(3.515)	(4.316)	(4.403)	(4.917)	(4.951)	(5.021)	(5.194)	(5.520)	(5.451)	(5.784)	(5.722)	(6.063)	(6.009)	(6.358)	(6.312)	(6.420)	(6.883)
Energy cost impacts	(0.355)	(0.717)	(1.070)	(1.309)	(1.369)	(1.394)	(1.414)	(1.448)	(1.481)	(1.509)	(1.537)	(1.565)	(1.589)	(1.601)	(1.634)	(1.680)	(1.712)	(1.749)	(1.763)	(1.772)
Revenue Requirement	3.671	2.229	2.037	(0.357)	(3.044)	(4.145)	(5.680)	(6.305)	(6.464)	(6.608)	(6.906)	(6.809)	(7.107)	(6.994)	(7.310)	(7.254)	(7.721)	(7.917)	(8.072)	(8.279)
NPV OF CUSTOMER IMPACT ($m)	**39.313**																			
BENEFITS	1.548	2.593	4.102	4.824	5.685	5.798	6.331	6.400	6.502	6.703	7.057	7.016	7.374	7.323	7.697	7.689	8.070	8.061	8.183	8.655
NPV of BENEFITS ($m)	**61.425**																			
EBITDA	4.670	4.417	5.306	3.837	2.028	1.027	0.013	(0.558)	(0.630)	(0.588)	(0.547)	(0.509)	(0.468)	(0.424)	(0.385)	(0.359)	(0.466)	(0.694)	(0.750)	(0.511)
New O&M expenses	0.549	0.405	0.833	0.629	0.613	0.626	0.639	0.653	0.668	0.683	0.699	0.716	0.734	0.753	0.772	0.793	0.815	0.837	0.861	0.886
COST	5.219	4.822	6.139	4.467	2.641	1.653	0.652	0.095	0.037	0.095	0.152	0.207	0.266	0.329	0.387	0.435	0.349	0.144	0.112	0.375
NPV of COSTS ($m)	**22.112**																			
TOTAL RESOURCE COST TEST	**2.778**																			

Alternative 2: Reactive AMI Deployment

$ Millions, except when indicated otherwise

LT Debt	52.6%
Common Equity	47.4%
Cost of LT Debt	4.9%
Return on Equity	9.8%
Income Tax (federal & state)	25.7%
Pre-tax WACC	6.83%

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Program capital costs	13.608	4.516	4.933	5.236	5.576	5.974	6.372	3.584	-	-	-	-	-	-	-	-	-	-	-	-
Avoided capital costs	(6.954)	(4.038)	(4.405)	(4.772)	(5.139)	(5.506)	(5.873)	(3.304)	-	-	-	-	-	-	-	-	-	-	-	-
Net capital expenditures	6.654	0.478	0.528	0.464	0.437	0.468	0.499	0.281	-	-	-	-	-	-	-	-	-	-	-	-
Amort for recovery	0.125	0.275	0.328	0.375	0.409	0.315	0.210	0.207	0.195	0.190	0.190	0.190	0.190	0.190	0.190	0.413	0.624	0.600	0.574	0.546
ADIT	(0.231)	0.112	0.059	0.047	0.032	(0.023)	(0.064)	(0.058)	(0.051)	(0.041)	(0.089)	(0.138)	(0.129)	(0.122)	(0.115)	(0.050)	0.013	0.013	0.009	0.002
Rate Base	6.298	6.614	6.873	7.009	7.069	7.198	7.423	7.438	7.192	6.961	6.683	6.355	6.037	5.725	5.420	4.958	4.347	3.760	3.194	2.650
Net Income	0.291	0.306	0.318	0.324	0.327	0.333	0.343	0.344	0.332	0.322	0.309	0.294	0.279	0.264	0.250	0.229	0.201	0.174	0.148	0.122
Taxes	0.101	0.106	0.110	0.112	0.113	0.115	0.119	0.119	0.115	0.111	0.107	0.102	0.097	0.092	0.087	0.079	0.070	0.060	0.051	0.042
EBT	0.392	0.411	0.428	0.436	0.440	0.448	0.462	0.463	0.447	0.433	0.416	0.395	0.376	0.356	0.337	0.308	0.270	0.234	0.199	0.165
Interest	0.163	0.171	0.178	0.181	0.183	0.186	0.192	0.192	0.186	0.180	0.173	0.164	0.156	0.148	0.140	0.128	0.112	0.097	0.083	0.068
EBIT	0.555	0.582	0.605	0.617	0.622	0.634	0.654	0.655	0.633	0.613	0.588	0.560	0.532	0.504	0.477	0.437	0.383	0.331	0.281	0.233
Depreciation	0.125	0.275	0.328	0.375	0.409	0.315	0.210	0.207	0.195	0.190	0.190	0.190	0.190	0.190	0.190	0.413	0.624	0.600	0.574	0.546
Remaining AMR NBV	1.170	1.188	1.188	1.170	1.134	1.080	1.008	0.486	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	1.850	2.046	2.121	2.163	2.166	2.029	1.872	1.348	0.829	0.802	0.778	0.749	0.721	0.694	0.667	0.849	1.007	0.931	0.855	0.779
New O&M expenses	0.784	0.586	0.918	0.672	0.924	0.688	0.953	0.719	0.668	0.683	0.699	0.716	0.734	0.753	0.772	0.793	0.815	0.837	0.861	0.886
O&M expense savings	(0.675)	(0.861)	(1.559)	(1.922)	(2.753)	(3.257)	(4.238)	(4.601)	(5.021)	(5.194)	(5.521)	(5.451)	(5.785)	(5.722)	(6.064)	(6.009)	(6.359)	(6.313)	(6.421)	(6.883)
Energy cost impacts	(0.102)	(0.244)	(0.398)	(0.585)	(0.788)	(1.010)	(1.248)	(1.426)	(1.481)	(1.509)	(1.537)	(1.565)	(1.589)	(1.601)	(1.634)	(1.680)	(1.712)	(1.749)	(1.763)	(1.772)
Revenue Requirement	1.856	1.527	1.082	0.328	(0.452)	(1.549)	(2.661)	(3.959)	(5.006)	(5.218)	(5.581)	(5.551)	(5.919)	(5.877)	(6.259)	(6.047)	(6.249)	(6.293)	(6.467)	(6.989)

NPV OF CUSTOMER IMPACT ($m)	**28.733**

BENEFITS	0.778	1.105	1.957	2.507	3.541	4.267	5.486	6.027	6.502	6.704	7.058	7.016	7.374	7.324	7.698	7.689	8.071	8.061	8.184	8.655
NPV of BENEFITS ($m)	**52.543**																			
EBITDA	1.850	2.046	2.121	2.163	2.166	2.029	1.872	1.348	0.829	0.802	0.778	0.749	0.721	0.694	0.667	0.849	1.007	0.931	0.855	0.779
New O&M expenses	0.784	0.586	0.918	0.672	0.924	0.688	0.953	0.719	0.668	0.683	0.699	0.716	0.734	0.753	0.772	0.793	0.815	0.837	0.861	0.886
COST	2.634	2.632	3.039	2.834	3.089	2.718	2.826	2.068	1.496	1.485	1.477	1.465	1.455	1.446	1.439	1.642	1.821	1.769	1.717	1.666
NPV of COSTS ($m)	**23.810**																			

TOTAL RESOURCE COST TEST	**2.207**

Alternative 3: Proactive SCM+ Deployment

$ Millions, except when indicated otherwise

LT Debt	52.6%
Common Equity	47.4%
Cost of LT Debt	4.9%
Return on Equity	9.8%
Income Tax (federal & state)	25.7%
Pre-tax WACC	6.83%

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Program capital costs	14.493	16.815	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided capital costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net capital expenditures	14.493	16.815	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amort for recovery	0.577	1.715	2.275	2.275	2.275	2.109	1.943	1.943	1.943	1.943	1.943	1.943	1.943	1.943	1.943	1.553	0.602	0.042	0.042	0.042
ADIT	(0.591)	(0.555)	(0.647)	(0.403)	(0.207)	(0.094)	(0.030)	0.006	0.006	0.006	0.105	0.345	0.487	0.487	0.487	0.387	0.142	(0.002)	(0.002)	(0.002)
Rate Base	13.324	27.870	24.948	22.270	19.787	17.584	15.610	13.673	11.736	9.799	7.961	6.363	4.907	3.451	1.995	0.829	0.369	0.325	0.281	0.238
Net Income	0.616	1.288	1.153	1.029	0.914	0.812	0.721	0.632	0.542	0.453	0.368	0.294	0.227	0.159	0.092	0.038	0.017	0.015	0.013	0.011
Taxes	0.213	0.446	0.399	0.357	0.317	0.282	0.250	0.219	0.188	0.157	0.127	0.102	0.079	0.055	0.032	0.013	0.006	0.005	0.005	0.004
EBT	0.829	1.734	1.552	1.385	1.231	1.094	0.971	0.851	0.730	0.610	0.495	0.396	0.305	0.215	0.124	0.052	0.023	0.020	0.018	0.015
Interest	0.344	0.720	0.645	0.575	0.511	0.454	0.403	0.353	0.303	0.253	0.206	0.164	0.127	0.089	0.052	0.021	0.010	0.008	0.007	0.006
EBIT	1.173	2.454	2.197	1.961	1.742	1.548	1.374	1.204	1.033	0.863	0.701	0.560	0.432	0.304	0.176	0.073	0.032	0.029	0.025	0.021
Depreciation	0.577	1.715	2.275	2.275	2.275	2.109	1.943	1.943	1.943	1.943	1.943	1.943	1.943	1.943	1.943	1.553	0.602	0.042	0.042	0.042
Remaining AMR NBV	4.682	6.482	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	6.432	10.651	4.472	4.236	4.018	3.658	3.318	3.147	2.977	2.806	2.644	2.503	2.375	2.247	2.119	1.626	0.635	0.070	0.066	0.062
New O&M expenses	0.798	1.245	1.479	1.314	1.549	1.386	1.623	1.462	1.451	1.542	1.784	1.627	1.871	1.717	1.964	1.812	2.061	1.912	1.915	2.269
O&M expense savings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy cost impacts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement	7.230	11.897	5.951	5.550	5.567	5.043	4.941	4.609	4.428	4.348	4.428	4.131	4.247	3.964	4.083	3.438	2.696	1.983	1.981	2.331

NPV OF CUSTOMER IMPACT ($m)	**(56.990)**

BENEFITS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NPV of BENEFITS ($m)	**-**																			
EBITDA	6.432	10.651	4.472	4.236	4.018	3.658	3.318	3.147	2.977	2.806	2.644	2.503	2.375	2.247	2.119	1.626	0.635	0.070	0.066	0.062
New O&M expenses	0.798	1.245	1.479	1.314	1.549	1.386	1.623	1.462	1.451	1.542	1.784	1.627	1.871	1.717	1.964	1.812	2.061	1.912	1.915	2.269
COST	7.230	11.897	5.951	5.550	5.567	5.043	4.941	4.609	4.428	4.348	4.428	4.131	4.247	3.964	4.083	3.438	2.696	1.983	1.981	2.331
NPV of COSTS ($m)	**56.990**																			

TOTAL RESOURCE COST TEST	**-**

Alternative 4: Reactive SCM+ Deployment

$ Millions, except when indicated otherwise

LT Debt	52.6%
Common Equity	47.4%
Cost of LT Debt	4.9%
Return on Equity	9.8%
Income Tax (federal & state)	25.7%
Pre-tax WACC	6.83%

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Program capital costs	6.954	4.038	4.405	4.772	5.139	5.506	5.873	3.304	-	-	-	-	-	-	-	-	-	-	-	-
Avoided capital costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net capital expenditures	6.954	4.038	4.405	4.772	5.139	5.506	5.873	3.304	-	-	-	-	-	-	-	-	-	-	-	-
Amort for recovery	0.326	0.786	1.068	1.374	1.704	1.893	2.106	2.412	2.522	2.522	2.522	2.522	2.522	2.522	2.522	2.383	2.109	1.828	1.522	1.192
ADIT	(0.462)	(0.116)	(0.199)	(0.264)	(0.313)	(0.390)	(0.462)	(0.441)	(0.323)	(0.182)	(0.050)	0.078	0.177	0.262	0.345	0.399	0.425	0.430	0.379	0.294
Rate Base	6.166	9.302	12.439	15.573	18.695	21.918	25.223	25.674	22.829	20.125	17.553	15.109	12.764	10.504	8.327	6.343	4.658	3.260	2.117	1.219
Net Income	0.285	0.430	0.575	0.719	0.864	1.013	1.165	1.186	1.055	0.930	0.811	0.698	0.590	0.485	0.385	0.293	0.215	0.151	0.098	0.056
Taxes	0.099	0.149	0.199	0.249	0.299	0.351	0.404	0.411	0.366	0.322	0.281	0.242	0.204	0.168	0.133	0.102	0.075	0.052	0.034	0.020
EBT	0.384	0.579	0.774	0.969	1.163	1.364	1.569	1.597	1.420	1.252	1.092	0.940	0.794	0.653	0.518	0.395	0.290	0.203	0.132	0.076
Interest	0.159	0.240	0.321	0.402	0.483	0.566	0.652	0.663	0.590	0.520	0.453	0.390	0.330	0.271	0.215	0.164	0.120	0.084	0.055	0.031
EBIT	0.543	0.819	1.095	1.371	1.646	1.930	2.221	2.260	2.010	1.772	1.545	1.330	1.124	0.925	0.733	0.558	0.410	0.287	0.186	0.107
Depreciation	0.326	0.786	1.068	1.374	1.704	1.893	2.106	2.412	2.522	2.522	2.522	2.522	2.522	2.522	2.522	2.383	2.109	1.828	1.522	1.192
Remaining AMR NBV	1.170	1.188	1.188	1.170	1.134	1.080	1.008	0.486	-	-	-	-	-	-	-	-	-	-	-	-
EBITDA	2.039	2.794	3.352	3.915	4.485	4.903	5.335	5.159	4.532	4.294	4.068	3.852	3.646	3.447	3.255	2.942	2.520	2.115	1.708	1.299
New O&M expenses	0.466	0.345	0.694	0.663	1.054	1.067	1.505	1.462	1.451	1.542	1.784	1.627	1.871	1.717	1.964	1.812	2.061	1.912	1.915	2.269
O&M expense savings	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Energy cost impacts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revenue Requirement	2.505	3.139	4.045	4.578	5.538	5.970	6.841	6.620	5.983	5.836	5.852	5.479	5.517	5.164	5.219	4.753	4.581	4.027	3.623	3.568
NPV OF CUSTOMER IMPACT ($m)	**(52.418)**																			
BENEFITS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NPV of BENEFITS ($m)	**-**																			
EBITDA	2.039	2.794	3.352	3.915	4.485	4.903	5.335	5.159	4.532	4.294	4.068	3.852	3.646	3.447	3.255	2.942	2.520	2.115	1.708	1.299
New O&M expenses	0.466	0.345	0.694	0.663	1.054	1.067	1.505	1.462	1.451	1.542	1.784	1.627	1.871	1.717	1.964	1.812	2.061	1.912	1.915	2.269
COST	2.505	3.139	4.045	4.578	5.538	5.970	6.841	6.620	5.983	5.836	5.852	5.479	5.517	5.164	5.219	4.753	4.581	4.027	3.623	3.568
NPV of COSTS ($m)	**52.418**																			
TOTAL RESOURCE COST TEST	**-**																			

Comparison of Alternatives

	Alternative 1 AMI Proactive Deployment	Alternative 2 AMI Reactive Deployment	Alternative 3 SCM+ Proactive Deployment	Alternative 4 SCM+ Reactive Deployment	Reference
Impact					
Customer Impact ($M) (NPV)	(39.3)	(28.7)	57	52.4	Figure LMK-2 and Exhibit LMK-1
TRC Test	2.78	2.21	0	0	Figure LMK-2 and Exhibit LMK-1
Technology					
Two-way Communication	✓	✓	×	×	Blankenship-4:5
Obviate the Need for Manual or Drive By Readings	✓	✓	×	×	Blankenship-8;12
Receive Information Back from the AMI Meters for Expansive Insight into the System	✓	✓	×	×	Blankenship-8
Deployment					
Targeted Based on Economies of Scale	✓	×	✓	×	Blankenship-6
Customer Benefits					
Improved Reliability	✓	✓	×	×	Blankenship-10:11
Immediate Detection of Power Interruption	✓	✓	×	×	Blankenship-8;10
Proactively Equipment Failure Prediction Before Failure Causes an Outage	✓	✓	×	×	Blankenship-10
Improved Service Reconnections (Near Real Time)	✓	✓	×	×	Blankenship-9
Better Storm Response Due to Pinpoint Outage Detection	✓	✓	×	×	Blankenship-8;11
Enhanced Customer Service	✓	✓	×	×	Cobern-13:14
Enhanced Customer Engagement Platform	✓	✓	×	×	Cobern-7:12
Personalized High Bill Alerts	✓	✓	×	×	Cobern-9;11
Weekly Energy Alerts (Email Required)	✓	✓	×	×	Cobern-11
Enhanced Home Energy Analysis Audit	✓	✓	×	×	Cobern-9:10
Enhanced Bill Comparison	✓	✓	×	×	Cobern-9
Highest Use Day	✓	✓	×	×	Cobern-10
35,000 Data Points a Year for Each Customer	✓	✓	×	×	Cobern-13
Increased Customer (and First Responders) Protection During an Emergency	✓	✓	×	×	Blankenship-9:10
Ability to "Self" Monitor and Report Meter Health - Improved Power Quality and Voltage to Customers	✓	✓	×	×	Blankenship-11
Enhanced Detection of Meter Failure or Damage	✓	✓	×	×	Blankenship-10
Operational Benefits					
Reduced Truck Rolls	✓	✓	×	×	Blankenship-8
Improved Company and Contractor Safety	✓	✓	×	×	Blankenship-13:14
Mitigate Tamper and Theft	✓	✓	×	×	Blankenship-9
Infrastructure Synergies Such as Volt/VAR Optimization	✓	✓	×	×	Blankenship-12
More Accurate Meter Readings	✓	✓	×	×	Blankenship-13

VERIFICATION

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

Lerah Kahn

Lerah M. Kahn

Commonwealth of Kentucky)
) Case No. 2024-00344
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lerah M. Kahn, on November 7, 2024.

Marilyn Michelle Caldwell

Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027